2021 Annual Results

Paramount Resources Ltd. Reports 2021 Annual Results and Increased Dividend and 2022 Guidance

Calgary, Alberta – March 2, 2022

Paramount Resources Ltd. ("Paramount" or the "Company") (TSX:POU) is pleased to report 2021 annual results that include record adjusted funds flow, continuing capital discipline, increased reserves with strong finding and development costs and recycle ratios and a 47% year-over-year reduction in net debt. Paramount is also pleased to announce that it is increasing its regular monthly dividend from $0.06 per share to $0.08 per share beginning March 2022 and forecasting higher 2022 production and free cash flow.

HIGHLIGHTS

- Annual sales volumes averaged 82,001 Boe/d (44% liquids) in 2021, in line with guidance. Fourth quarter 2021 sales volumes averaged 85,265 Boe/d (44% liquids).(1)
  - Fourth quarter sales volumes at Karr averaged 41,629 Boe/d (50% liquids) compared to 39,878 Boe/d (52% liquids) in the third quarter.
  - Fourth quarter sales volumes at Wapiti averaged 14,350 Boe/d (60% liquids) compared to 14,651 Boe/d (62% liquids) in the third quarter.
- Cash from operating activities was $482.1 million in 2021 and $191.8 million in the fourth quarter. Adjusted funds flow in 2021 was $499.8 million ($3.74 per basic share) and $174.6 million ($1.29 per basic share) in the fourth quarter, representing annual and quarterly records for the Company.(2)
- 2021 capital expenditures totaled $274.6 million and were predominantly focused on drilling and completion activities at Karr, Wapiti and the Willesden Green Duvernay. Capital expenditures were $15.4 million less than the midpoint of previous guidance, reflecting strong execution and a continued focus on cost control.
- In 2021, the Company achieved proved plus probable ("P+P") reserves additions of 82.8 MMBoe, P+P finding and development ("F&D") costs of $2.12/Boe and a P+P recycle ratio of 12.6x. Total proved ("TP") reserves additions in 2021 were 72.9 MMBoe, with TP F&D costs of $6.72/Boe and TP recycle ratio of 4.0x.(3)

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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 is a capital management measure used by Paramount. Adjusted funds flow per share is a supplementary financial measure. Refer to the "Specified Financial Measures" section for more information on these measures.

(3) Readers are referred to the advisories concerning "Reserves Data". Reserves evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel") as of December 31, 2021 in accordance with National Instrument 51-101 definitions, standards and procedures. Reserves are gross reserves representing working interest before royalties. F&D costs and recycle ratio are non-GAAP ratios. Refer to the "Specified Financial Measures" section and "Oil and Gas Measures and Definitions" in the Advisories section for more information on these measures.

- Operating costs averaged $11.37/Boe in 2021, 4% lower than 2020. Karr operating costs averaged $9.57/Boe in 2021.(1)

- Abandonment and reclamation expenditures totaled $25.4 million in 2021, net of $9.7 million funded under the Alberta Site Rehabilitation Program ("ASRP").

- Free cash flow was $191.8 million ($1.44 per basic share) in 2021 and $99.0 million ($0.73 per basic share) in the fourth quarter.(2)

- The Company reduced net debt by $397.4 million year-over-year to $456.7 million at December 31, 2021.(3)

  - Drawings under Paramount's $900 million credit facility were $389.1 million at December 31, 2021.

  - Non-core property dispositions generated aggregate proceeds of $165.5 million in 2021 and a further $67 million was received in the year in settlement of the previously disclosed dissent proceedings respecting an investment in securities.

  - In the fourth quarter, all $35 million of the Company's 7.5% convertible debentures were converted by holders into 5.2 million class A common shares ("Common Shares") of the Company.

  - Net debt to adjusted funds flow at year-end was approximately 0.9x.

- Net debt does not account for the $372.1 million carrying value of the Company's investments in securities as at December 31, 2021.

- The Company implemented a regular monthly dividend of $0.02 per Common Share in July 2021 and tripled it to $0.06 per Common Share in November 2021. The Company is increasing its monthly dividend to $0.08 per Common Share beginning in March 2022.

- In the first quarter of 2022, the Company completed a highly complementary asset acquisition in the Grande Prairie Region for $24.4 million (the "Grande Prairie Acquisition"), which is expected to contribute approximately 1,000 Boe/d to annual 2022 sales volumes.

RESERVES

- Paramount's P+P reserves increased 5% to 662 MMBoe in 2021 compared to 632 MMBoe in 2020. TP and proved developed producing ("PDP") reserves increased 9% and 4%, respectively.

  - In the Grande Prairie Region, where the majority of 2021 development activity occurred and the Company achieved further reductions in its cost structure, P+P reserves were up 8%, TP reserves were up 2% and PDP reserves were up 20%.

- The Company's reserves replacement ratio was 1.4x for PDP reserves.(4)

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(1) Operating costs on a $/Boe basis is a supplementary financial measure. Refer to the "Specified Financial Measures" section for more information on this measure.
(2) Free cash flow is a capital management measure used by Paramount. Free cash flow per share is a supplementary financial measure. Refer to the "Specified Financial Measures" section for more information on these measures.
(3) Net debt and net debt to adjusted funds flow are capital management measures used by Paramount. Refer to the "Specified Financial Measures" section for more information on these measures.
(4) See "Oil and Gas Measures and Definitions" in the Advisories section of this document for a description of the calculation and use of reserves replacement ratio.

- Paramount achieved strong F&D costs and recycle ratios in 2021 due to lower drilling, completion, equipping and tie-in costs across its major resource plays and higher netbacks.(1)

	F&D ($/Boe)		Recycle Ratio (x)	
	Total	Grande Prairie	Total	Grande Prairie
Proved Developed Producing	**6.22**	6.53	4.3	5.1
Total Proved	**6.72**	1.99	4.0	16.8
Proved plus Probable	**2.12**	0.59	12.6	56.2

- Estimated future net revenue at December 31, 2021, discounted at 10% before tax, totaled $1.4 billion for PDP reserves, $3.6 billion for TP reserves and $6.2 billion for P+P reserves.(2)

2022 GUIDANCE

The Company's planned 2022 capital expenditures remain unchanged at a range of between $500 million and $540 million, with anticipated efficiency gains offsetting certain inflationary pressures. The 2022 capital budget is focused on development and debottlenecking operations at Karr to grow production to 43,000 to 47,000 Boe/d in the second half of 2022, development activities at Wapiti to achieve targeted plateau production of 30,000 Boe/d in 2023 and development activities at Kaybob to advance the Duvernay plays at Kaybob Smoky and Kaybob North. 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 is increasing its 2022 annual production guidance to average between 91,000 Boe/d and 95,000 Boe/d (46% liquids) to reflect the impact of the Grande Prairie Acquisition. Although production in early 2022 at Wapiti was affected by two unplanned outages totaling 18 days at the third-party operated Wapiti natural gas processing facility, well outperformance is anticipated to offset this unplanned downtime.

- First half 2022 sales volumes are still expected to average between 81,000 Boe/d and 85,000 Boe/d (44% liquids), taking into account a planned 16-day full field outage at Karr during the second quarter for turnaround activities at third-party midstream facilities.
- Second half 2022 sales volumes are now expected to average between 101,000 Boe/d and 105,000 Boe/d (47% liquids) as numerous new wells from the Company's capital program are brought onstream.

Paramount is increasing its forecast of 2022 free cash flow from approximately $455 million to approximately $590 million to reflect higher commodity price assumptions and higher forecast production.(3)

(1) Netback is a non-GAAP financial measure. Refer to the "Specified Financial Measures" section for more information on this measure.
(2) Net present values of future net revenue were determined using forecast prices and costs and do not represent fair market value.
(3) 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 expense, (iv) realized pricing of $61.95/Boe (US$86.30/Bbl WTI, US$4.74/MMBtu NYMEX, $4.25/GJ AECO), (v) royalties of $9.45/Boe, (vi) operating costs of $11.15/Boe, (vii) transportation and processing costs of $3.75/Boe and (viii) a $US/$Cdn exchange rate of $0.788.

As previously disclosed, the Company's free cash flow priorities are (i) the achievement of targeted leverage levels, (ii) shareholder returns and (iii) incremental growth.

- The Company expects to achieve its net debt target of about $300 million in the third quarter of 2022 based on its 2022 free cash flow forecast.
- Remaining 2022 free cash flow will be available to:
    - further augment shareholder returns through additional increases in the regular monthly dividend, special dividends or opportunistic repurchases of Common Shares under the Company's normal course issuer bid; and
    - reinvest in incremental organic growth or strategic acquisitions.

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

PRELIMINARY 2023 BUDGET

Paramount's anticipated 2023 capital expenditure budget, based on preliminary planning and current market conditions, remains unchanged at a range of between $475 million and $525 million.

Paramount expects that a capital program in this range will result in 2023 average sales volumes of between 98,500 Boe/d and 103,500 Boe/d (48% liquids), 1,000 Boe/d higher than previously estimated.

Paramount is updating its estimate of 2023 free cash flow that would be expected from such a capital program from approximately $450 million to approximately $580 million to reflect higher commodity price assumptions and higher estimated production.(1)

FIVE-YEAR OUTLOOK

Paramount is updating its previously provided five-year outlook to reflect recent commodity prices. The Company now anticipates cumulative free cash flow through to the end of 2026 of over $3.3 billion, up from $2.7 billion. The Company continues to anticipate annual capital expenditures of approximately $500 million and a compound annual production growth rate of approximately 5 percent through the period. (2)

INCREASED DIVIDEND

Paramount's Board of Directors has approved an increase in the Company's regular monthly dividend from $0.06 to $0.08 per Common Share. The first increased dividend will be payable on March 31, 2022 to shareholders of record on March 15, 2022. The dividend will be designated as an "eligible dividend" for Canadian income tax purposes.

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(1) The stated 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 net abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $54.60/Boe (US$76.96/Bbl WTI, US$3.84/MMBtu NYMEX, $3.39/GJ AECO), (v) royalties of $8.55/Boe, (vi) operating costs of $10.65/Boe, (vii) transportation and processing costs of $3.65/Boe and (viii) a $US/$Cdn exchange rate of $0.787.

(2) The five-year outlook is based on preliminary planning and current market conditions and is subject to change as conditions evolve. 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 February 16, 2022, and (v) internal management estimates of future royalties, operating costs and transportation and processing costs.

HEDGING

Paramount has hedged approximately 33% of its 2022 forecast production to provide greater free cash flow certainty. The Company's current 2022 hedging position is summarized below:

	Type [1]	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Average Price [2]
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	3,500	3,500	3,500	3,500	US$75.79/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	9,500	–	–	–	CDN$87.90/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	3,500	3,500	3,500	CDN$91.38/Bbl
Oil – WTI Collars (Bbl/d)	Financial	7,000	7,000	7,000	7,000	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)
Condensate – Basis (Sale) (Bbl/d)	Physical	2,098	–	–	–	WTI + US$3.13/Bbl
Sweet Crude Oil – Basis (Sale) (Bbl/d)	Physical	–	5,186	–	–	WTI - US$2.15/Bbl
Gas – NYMEX Swaps (Sale) (MMBtu/d)	Financial	40,000	–	–	–	US$4.15/MMBtu
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	40,000	–	–	–	CDN$4.06/GJ
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$4.03/MMBtu
Fx – CDN/USD Swaps (US$MM/Month)	Financial	$5	$5	$5	$5	1.27 C$ / US$
Fx – CDN/USD Collars (US$MM/Month)	Financial	$5	$5	$5	$3.3	1.25 C$ / US$ (Floor) 1.30 C$ / US$ (Ceiling)

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

COMPLETE ANNUAL RESULTS

Paramount's: (i) complete annual results, including a review of operations, the Company's audited consolidated financial statements as at and for the year ended December 31, 2021 (the "Consolidated Financial Statements") and the accompanying management's discussion and analysis (the "MD&A") and (ii) 2021 annual information form, which contains additional important information concerning the Company's reserves, properties and operations, can be obtained on SEDAR at www.sedar.com or on Paramount's website at www.paramountres.com/investors/financial-shareholder-reports.

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

ANNUAL GENERAL MEETING

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

Product Type Information
This document 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. See the Product Type Information section at page 108 of this document for a complete breakdown of sales volumes for applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Specified Financial Measures
This document includes references to certain non-GAAP financial measures, non-GAAP ratios, capital management measures used by Paramount and supplementary financial measures. Readers are referred to the Specified Financial Measures section at page 109 of this document for important additional information concerning these measures.

Advisories
Readers are referred to the Advisories section at page 113 of this document for important information and advisories respecting Forward-Looking Information, Reserves Data and Oil and Gas Measures and Definitions.

FINANCIAL AND OPERATING RESULTS [(1)]

($ millions, except as noted)	Three months ended December 31				Year ended December 31			
	2021		2020		2021		2020	
Net income (loss)	101.0		311.5		236.9		(22.7)	
per share – basic ($/share)	*0.75*		*2.35*		*1.77*		*(0.17)*	
per share – diluted ($/share)	*0.70*		*2.35*		*1.67*		*(0.17)*	
Cash from operating activities	191.8		53.2		482.1		80.9	
per share – basic ($/share)	*1.42*		*0.40*		*3.61*		*0.61*	
per share – diluted ($/share)	*1.33*		*0.40*		*3.39*		*0.61*	
Adjusted funds flow	174.6		67.9		499.8		150.0	
per share – basic ($/share)	*1.29*		*0.51*		*3.74*		*1.12*	
per share – diluted ($/share)	*1.21*		*0.51*		*3.51*		*1.12*	
Free cash flow	99.0		0.6		191.8		(113.7)	
per share – basic ($/share)	*0.73*		*0.01*		*1.44*		*(0.85)*	
per share – diluted ($/share)	*0.69*		*0.01*		*1.36*		*(0.85)*	
Total assets					3,885.1		3,497.0	
Long-term debt					386.3		813.5	
Net debt					456.7		854.1	
Common shares outstanding *(millions)* (2)					139.2		132.3	
Sales volumes (3)								
Natural gas (MMcf/d)	284.8		256.3		275.2		248.7	
Condensate and oil (Bbl/d)	32,342		25,752		30,989		22,565	
Other NGLs (Bbl/d)	5,462		4,987		5,147		4,325	
Total (Boe/d)	85,265		73,460		82,001		68,340	
% liquids	*44%*		*42%*		*44%*		*39%*	
Grande Prairie Region (Boe/d)	56,035		37,782		51,869		31,076	
Kaybob Region (Boe/d)	21,725		27,056		22,588		28,685	
Central Alberta & Other Region (Boe/d)	7,505		8,622		7,544		8,579	
Total (Boe/d)	85,265		73,460		82,001		68,340	
Netback		*$/Boe (4)*		*$/Boe (4)*		*$/Boe (4)*		*$/Boe (4)*
Natural gas revenue	124.7	*4.76*	66.7	*2.83*	373.3	*3.72*	204.9	*2.25*
Condensate and oil revenue	281.1	*94.46*	123.3	*52.03*	926.5	*81.91*	383.8	*46.47*
Other NGLs revenue	27.4	*54.61*	9.5	*20.61*	78.6	*41.84*	24.7	*15.63*
Royalty and other revenue	1.1	—	2.5	—	4.6	—	12.6	—
Petroleum and natural gas sales	434.3	*55.37*	202.0	*29.89*	1,383.0	*46.21*	626.0	*25.03*
Royalties	(52.5)	*(6.69)*	(11.7)	*(1.73)*	(127.0)	*(4.24)*	(31.3)	*(1.25)*
Operating expense	(91.0)	*(11.61)*	(79.8)	*(11.80)*	(340.4)	*(11.37)*	(297.1)	*(11.88)*
Transportation and NGLs processing	(26.1)	*(3.33)*	(24.6)	*(3.63)*	(114.5)	*(3.83)*	(101.3)	*(4.05)*
Netback	264.7	*33.74*	85.9	*12.73*	801.1	*26.77*	196.3	*7.85*
Risk management contract settlements	(72.4)	*(9.23)*	7.9	*1.18*	(218.3)	*(7.29)*	37.6	*1.50*
Netback including risk management contract settlements	192.3	*24.51*	93.8	*13.91*	582.8	*19.48*	233.9	*9.35*
Capital expenditures								
Grande Prairie Region	57.7		64.3		228.6		196.9	
Kaybob Region	3.8		1.8		14.5		16.4	
Central Alberta & Other Region	2.6		0.8		25.3		4.6	
Corporate	1.6		(1.8)		6.2		2.3	
Total	65.7		65.1		274.6		220.2	
Asset retirement obligations settlements	7.0		0.1		25.4		35.0	

(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 results have been reclassified to conform with the current years' presentation.

(2) Common shares are presented net of shares held in trust under the Company's restricted share unit plan: 2021: 1.5 million; 2020: 1.9 million; 2019: 0.9 million.

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

(4) Natural gas revenue presented as $/Mcf.

REVIEW OF OPERATIONS

The Canadian upstream energy sector rebounded in 2021 buoyed by stronger commodity prices. Paramount's achievement of structural cost reductions, further improvements to well design, rigorous planning and disciplined execution positioned it to capitalize on this improving macroeconomic environment.

In 2021, Paramount:

- Delivered on the Company's 2021 production and capital expenditure guidance with production directly in line and total capital expenditures coming in $15.4 million less than the midpoint of previous guidance provided on November 4, 2021.
- Reached targeted plateau production of approximately 40,000 Boe/d at the Company's flagship Karr property in the first quarter and sustained that level of production for the remainder of the year.
- Reduced average per well drilling, completion, equipping and tie-in ("DCET") costs by approximately 20% at Karr and 10% at Wapiti compared to 2020.
- Reduced per unit operating costs by 4% compared to 2020 to approximately $11.37/Boe and reduced Karr operating costs to below $10.00/Boe in the final three quarters of the year.
- Achieved payouts of approximately 4 months at the Karr 3-10 and 7-18 pads, the quickest in the history of the Company's Montney development.
- Drilled the longest horizontal well in Paramount's history, in the Willesden Green Duvernay area, with the lateral reaching approximately 4,000 meters and the well having a total measured depth of approximately 7,400 meters.
- Abandoned 156 wells, including 137 wells under the Company's area-based closure program at Zama.
- Completed several non-core assets dispositions for proceeds of $165.5 million.
- Reduced net debt by $397.4 million year-over-year, or approximately 47%, to $456.7 million. Net debt does not account for the $372.1 million carrying value of the Company's investments in securities as at December 31, 2021.

Sales volumes averaged 82,001 Boe/d (44% liquids) in 2021 and 85,265 Boe/d (44% liquids) in the fourth quarter of 2021. Production from the Grande Prairie Region represented 63% of 2021 sales volumes, averaging 51,869 Boe/d (55% liquids).

The Company's 2022 capital budget is expected to range between $500 million and $540 million, excluding land acquisitions and abandonment and reclamation activities. Paramount's capital allocation remains primarily focused on its two large-scale Montney developments at Karr and Wapiti in the Grande Prairie Region, but now also includes amounts for the development of its Duvernay assets at Kaybob North and Kaybob Smoky. In addition, capital is being deployed to pursue other high potential return opportunities at Kaybob in 2022 including Montney oil, Montney gas, Gething oil and an expansion of the Company's Kaybob Montney Oil enhanced oil recovery project.

In the first quarter of 2022, the Company successfully closed a highly complementary acquisition in the Grande Prairie Region for $24.4 million. The acquisition is expected to contribute approximately 1,000 Boe/d to annual 2022 sales volumes.

GRANDE PRAIRIE REGION

Development activities in the Grande Prairie Region are focused at the Karr and Wapiti properties, located south of Grande Prairie, Alberta, in the over-pressured liquids-rich Deep Basin Montney trend. While the majority of activity has been focused on the development of the Middle Montney, Paramount is beginning to more actively test and develop the Upper and Lower Montney layers as well. At December 31, 2021, Paramount held approximately 100,000 net acres of Montney rights in the Grande Prairie Region.

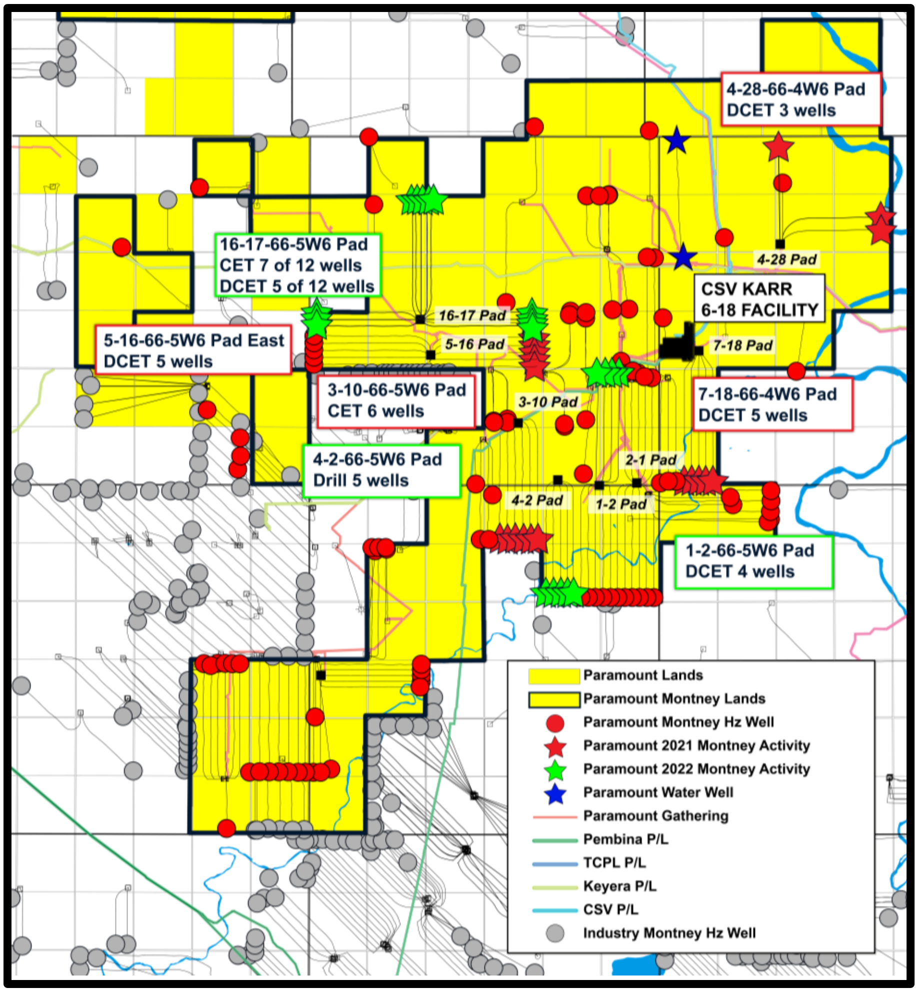
Grande Prairie Region sales volumes averaged 51,869 Boe/d (55% liquids) in 2021, the majority of which was liquids rich production from the Karr development. Capital expenditures in 2021 in the Grande Prairie Region totaled approximately $228.6 million, which was focused primarily on drilling and completion operations at Karr and Wapiti.

Grande Prairie Region sales volumes and netbacks are summarized below:

	Three months ended December 31				Year ended December 31			
	2021		2020		**2021**		2020	
Sales volumes (1)								
Natural gas (MMcf/d)	**158.9**		94.3		**141.0**		78.6	
Condensate and oil (Bbl/d)	**26,278**		19,635		**25,258**		16,005	
Other NGLs (Bbl/d)	**3,276**		2,429		**3,103**		1,964	
Total (Boe/d)	**56,035**		37,782		**51,869**		31,076	
% liquids	***53%***		*58%*		***55%***		*58%*	
Netback (2)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Petroleum and natural gas sales	**318.6**	***61.81***	125.1	*36.00*	**1,006.1**	***53.14***	356.2	*31.32*
Royalties	**(39.8)**	***(7.74)***	(6.2)	*(1.78)*	**(87.2)**	***(4.61)***	(14.3)	*(1.26)*
Operating expense	**(54.9)**	***(10.64)***	(42.4)	*(12.20)*	**(205.3)**	***(10.84)***	(162.4)	*(14.28)*
Transportation and NGLs processing	**(19.0)**	***(3.68)***	(14.2)	*(4.07)*	**(82.9)**	***(4.37)***	(53.1)	*(4.66)*
	204.9	***39.75***	62.3	*17.95*	**630.7**	***33.32***	126.4	*11.12*

(1) Refer to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.
(2) Netback is a non-GAAP financial measure. Netback presented on a $/Boe basis is a non-GAAP ratio. Refer to the "Specified Financial Measures" section of this document for more information on these measures.

KARR AREA



Karr sales volumes and netbacks are summarized below:

	Three months ended December 31				Year ended December 31			
	2021		2020		**2021**		2020	
Sales volumes (1)								
Natural gas (MMcf/d)	**124.0**		70.5		**109.2**		56.3	
Condensate and oil (Bbl/d)	**18,521**		13,348		**17,858**		10,028	
Other NGLs (Bbl/d)	**2,449**		1,817		**2,330**		1,361	
Total (Boe/d)	**41,629**		26,914		**38,381**		20,777	
% liquids	***50%***		*56%*		***53%***		*55%*	
Netback (2)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Petroleum and natural gas sales	**229.6**	***59.96***	86.1	*34.79*	**725.4**	***51.78***	234.6	*30.86*
Royalties	**(35.7)**	***(9.32)***	(4.6)	*(1.87)*	**(74.5)**	***(5.32)***	(9.7)	*(1.28)*
Operating expense	**(36.0)**	***(9.38)***	(27.8)	*(11.24)*	**(134.1)**	***(9.57)***	(107.2)	*(14.10)*
Transportation and NGLs processing	**(14.0)**	***(3.68)***	(10.5)	*(4.26)*	**(59.7)**	***(4.26)***	(35.4)	*(4.65)*
	143.9	***37.58***	43.2	*17.42*	**457.1**	***32.63***	82.3	*10.83*

(1) Refer to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.
(2) Netback is a non-GAAP financial measure. Netback presented on a $/Boe basis is a non-GAAP ratio. Refer to the "Specified Financial Measures" section of this document for more information on these measures.

The 2021 capital program at Karr focused on drilling 20 Montney wells and bringing on production 19 Montney wells. In the first half of 2021, the Company brought onstream nine new Montney wells, six of which were drilled and completed in the fourth quarter of 2020 at the 3-10 pad, while the remaining three wells at the 4-28 pad were drilled and completed in 2021. Over the second half of 2021 Paramount brought on production an additional ten wells. The five-well 7-18 pad that was drilled in the first half of the year was brought onstream early in the third quarter and the five well 5-16 East pad that was drilled and completed in the second half of the year was brought onstream in the fourth quarter of 2021. The Company also commenced drilling operations at the 12-well 16-17 pad where seven wells were drilled by year-end 2021.

The 5-16 East pad, the most recent to be brought onstream at Karr, has performed in line with type well projections, averaging gross peak 30-day production per well of 1,601 Boe/d (4.2 MMcf/d of shale gas and 907 Bbl/d of NGLs) with an average CGR of 218 Bbl/MMcf.[(1)]

Paramount continues to focus on further improving well deliverability while also seeking new and innovative ways to streamline its operations. This parallel focus has resulted in the Company's highest capital efficiencies since the Company's current Karr development began in 2016 despite experiencing recent inflationary pressures. Average 2021 per-well DCET costs decreased by approximately 20% compared to the 2020 drilling program and approximately 50% compared to the 2019 drilling program.

Paramount achieved a major milestone at Karr in 2021, reaching production of approximately 40,000 Boe/d in the first quarter. Production was sustained over the remaining three quarters of the year, averaging 40,067 Boe/d (52% liquids). The Company continues to seek efficiencies in its operations while maintaining its focus on safety, asset integrity, reliability and environmental performance. The installation of additional gas lift compression contributed to stronger fourth quarter sales volumes.

Netbacks materially increased in 2021 compared to 2020 as a result of higher commodity prices, higher production and lower per-unit operating expenses. Fourth quarter operating expenses of $9.38/Boe remain below the Company's target of approximately $10.00/Boe as a consequence of the Company's continued focus on capturing efficiencies and streamlining operations. Higher royalty rates resulting from higher commodity prices as well as an increased proportion of wells having fully utilized their new well royalty incentives partially offset the increase in revenues.

The Company's 2022 activities at Karr will be focused on drilling, completion and debottlenecking operations. Production is expected to grow from 39,000 to 41,000 Boe/d in the first quarter of 2022 to 43,000 to 47,000 Boe/d in the second half of 2022. Second quarter production is anticipated to be 36,000 to 38,000 Boe/d, reflecting the planned 16-day full field outage for turnaround activities at third-party midstream facilities.

Paramount plans to drill 12 Montney wells and bring onstream a total of 16 new Montney wells. The seven wells at the 12-well 16-17 pad that were drilled in 2021 are scheduled to be completed, tied-in and brought onstream by the second quarter with the remaining five wells scheduled to be drilled, completed, tied-in and brought onstream by the third quarter. The Company also plans to drill, complete, tie-in and bring on production the four-well 1-2 North pad in the second half of 2022 and commence drilling the five-well 4-2 South pad in the fourth quarter, three wells of which are anticipated to have finished drilling operations in 2022. In addition, Paramount plans to bring onstream additional gas lift compression in the year to support liquids production as well as build out certain infrastructure to debottleneck future production.

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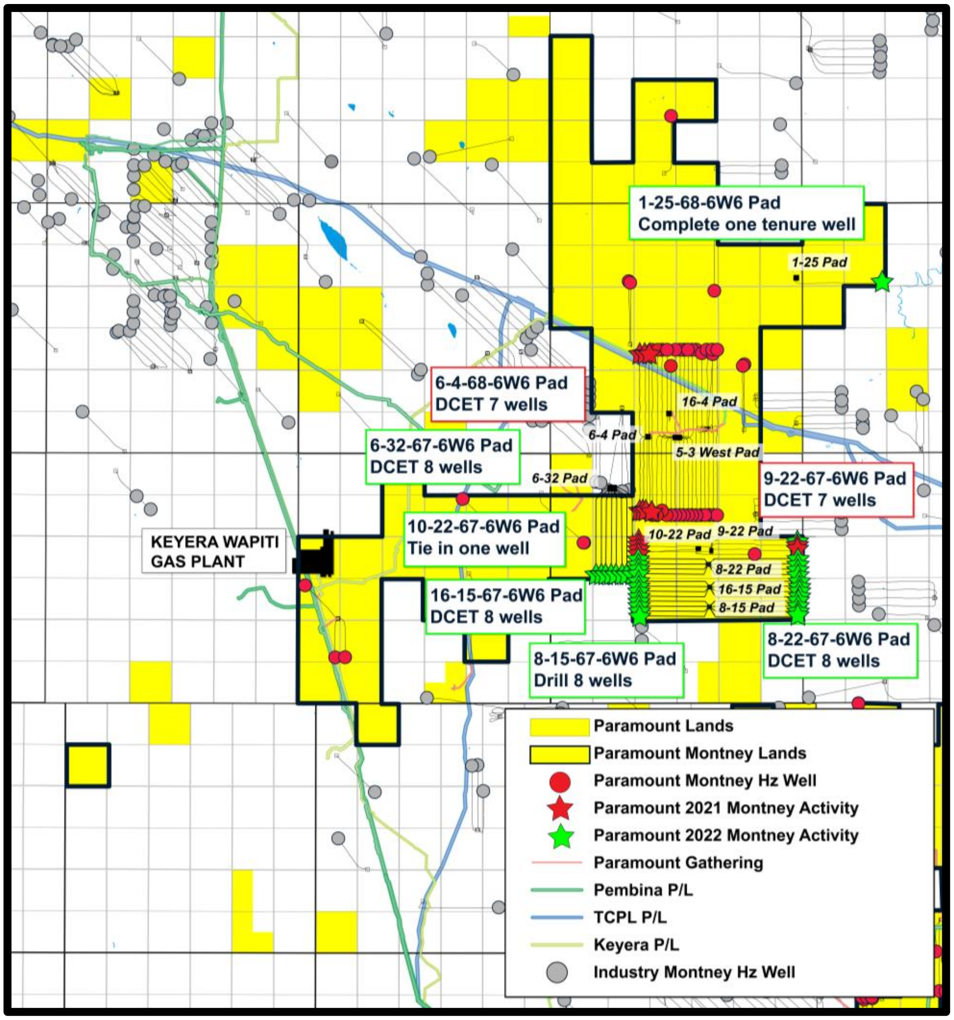
(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 6% and liquids sales volumes are lower by approximately 6% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, 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:

	Three months ended December 31				Year ended December 31			
	2021		2020		**2021**		2020	
Sales volumes (1)								
Natural gas (MMcf/d)		**34.7**		23.3		**31.6**		21.9
Condensate and oil (Bbl/d)		**7,749**		6,286		**7,395**		5,959
Other NGLs (Bbl/d)		**819**		589		**764**		591
Total (Boe/d)		**14,350**		10,764		**13,432**		10,207
% liquids		***60%***		*64%*		***61%***		*64%*
Netback (2)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Petroleum and natural gas sales	**88.9**	***67.28***	38.9	*39.30*	**280.3**	***57.17***	121.0	*32.39*
Royalties	**(4.2)**	***(3.17)***	(1.6)	*(1.58)*	**(12.6)**	***(2.58)***	(4.6)	*(1.23)*
Operating expense	**(18.7)**	***(14.10)***	(14.2)	*(14.36)*	**(70.1)**	***(14.30)***	(53.6)	*(14.35)*
Transportation and NGLs processing	**(4.9)**	***(3.71)***	(3.6)	*(3.62)*	**(23.3)**	***(4.73)***	(17.6)	*(4.71)*
	61.1	***46.30***	19.5	*19.74*	**174.3**	***35.56***	45.2	*12.10*

(1) Refer to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.
(2) Netback is a non-GAAP financial measure. Netback presented on a $/Boe basis is a non-GAAP ratio. Refer to the "Specified Financial Measures" section of this document for more information on these measures.

Development activities at Wapiti in 2021 focused on drilling the remaining four wells at the seven-well 6-4 pad and subsequent completion, tie-in and bringing onstream of all seven wells early in the third quarter. Drilling, completion and tie-in activities were also conducted at the seven-well 9-22 pad where three wells were brought onstream in late-December. Additional 2021 activities included the commencement of drilling operations at the eight-well 8-22 pad late in the year and the drilling of a tenure well in the third quarter.

Production in 2021 increased primarily as a result of new well production from both the 6-4 pad that came onstream in the third quarter and the 5-3 West pad that came onstream in late 2020 and from higher facility reliability at the third-party Wapiti natural gas processing plant (the "Wapiti Plant") relative to 2020.

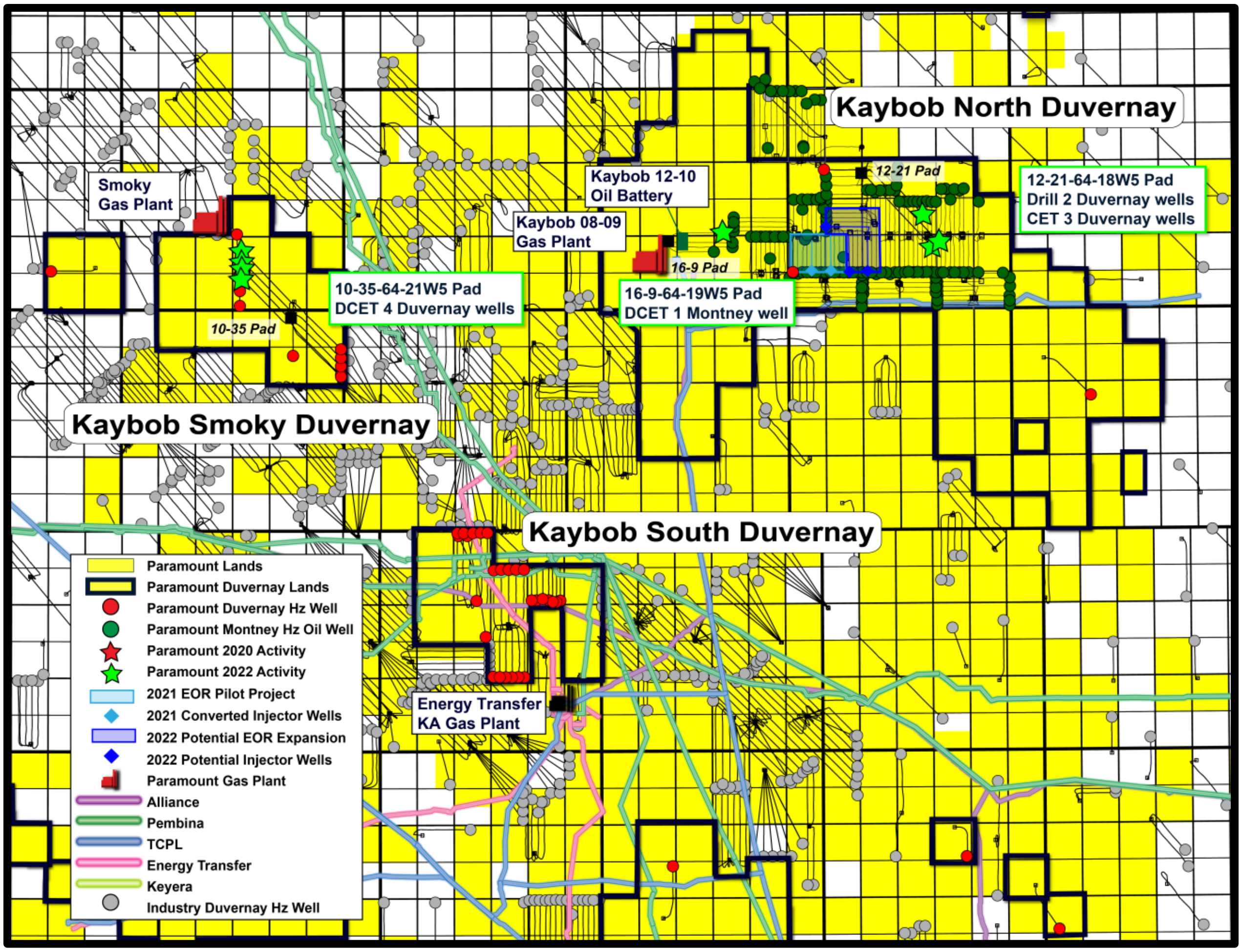
In 2022, the Company plans to grow Wapiti production to 27,000 Boe/d by year-end by drilling 32 new Montney wells and bringing onstream a total of 23 Montney wells. Production is expected to grow from approximately 12,000 to 16,000 Boe/d in the first quarter of 2022 to 23,000 to 27,000 Boe/d in the fourth quarter. Production at Wapiti in early 2022 was impacted by two unplanned outages at the Wapiti Plant totaling 18 days.

The remaining four wells at the seven-well 9-22 pad were brought on production in the first quarter of 2022. One legacy well at the adjacent 10-22 pad is planned to come on production in early March. Drilling operations at the eight-well 8-22 pad are ongoing and Paramount plans to complete, tie-in and bring onstream all eight wells in the second quarter. Three additional eight-well pads are planned to be drilled in 2022 with the 6-32 pad scheduled to be brought onstream over the third and fourth quarters and two wells on the 16-15 pad scheduled to be brought onstream in late 2022. The remaining six wells on the 16-15 pad and eight wells on the 8-15 pad that are anticipated to be drilled in 2022 are expected to be brought onstream in 2023.

KAYBOB REGION

Paramount has a large portfolio of resource plays in the Kaybob Region, including approximately 192,000 net acres of Duvernay rights and approximately 260,000 net acres of Montney rights.

The Company's key development areas include Duvernay formation targets at Kaybob Smoky, Kaybob South and Kaybob North and Montney formation targets at Kaybob North and Ante Creek. Paramount owns and operates extensive processing and gathering infrastructure in the Region which supports the development of these plays.



Kaybob Region sales volumes averaged 22,588 Boe/d (28% liquids) in 2021 compared to 28,685 Boe/d (27% liquids) in 2020. The decrease in production is largely attributable to natural declines and the disposition of non-core assets. Capital expenditures in 2021 totaled approximately $14.5 million. Activities in 2021 were focused on maintenance and land retention.

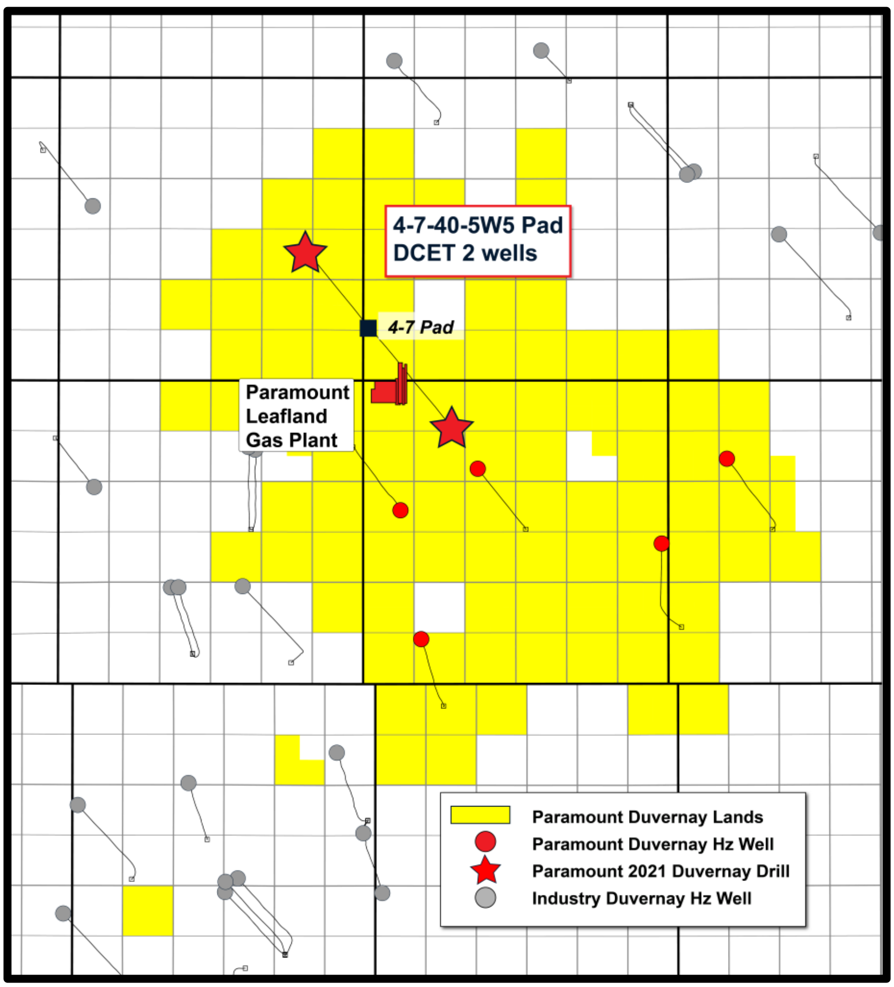
In 2022, Paramount plans to pursue the development of its Duvernay assets at Kaybob North and Kaybob Smoky. At Kaybob North, the Company plans to drill the remaining two wells at the three-well 12-21 pad and bring all three wells onstream in the fourth quarter. At Kaybob Smoky, plans include the expansion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

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

The Company plans to deploy approximately 8% of its capital expenditure budget to pursue other high return opportunities at Kaybob in 2022, including bringing onstream four (2.5 net) Montney gas wells, two Montney oil wells and two Gething oil wells, seven (5.5 net) of which will be drilled in 2022. Activities also include an expansion of the enhanced oil recovery project at the Company's Kaybob Montney Oil property contingent on the success of the existing pilot.

CENTRAL ALBERTA AND OTHER REGION

The Central Alberta and Other Region includes multiple land and resource plays, including approximately 73,000 net acres of Duvernay rights at Willesden Green. The Region also includes lands and production in the Horn River Basin in northeast British Columbia. The map below highlights the Company's land position at Willesden Green.



Central Alberta and Other Region sales volumes averaged 7,544 Boe/d (18% liquids) in 2021 compared to 8,579 Boe/d (14% liquids) in 2020. Sales volumes decreased primarily due to the sale of the non-operated Birch assets in July 2021. New well production from the two-well Willesden Green Duvernay 4-7 pad that was brought onstream early in the third quarter offset production declines. Despite being restricted by facility constraints, average gross peak 30-day production per well at the 4-7 pad was 1,533 Boe/d (3.5 MMcf/d of shale gas and 956 Bbl/d of NGLs) with an average CGR of 276 Bbl/MMcf. (1)

The Company holds a material, contiguous Duvernay position at Willesden Green and continues to actively evaluate longer-term full field development plans for this asset. Material learnings from the drilling of the two wells at the 4-7 pad, particularly in drilling long reach laterals in the Duvernay formation, have resulted in further optimization to pad layouts in the full field development plans across the Company's Duvernay lands, improving economics. DCET costs at the 4-7 pad averaged $11.1 million per well. The Company anticipates reductions in average well costs once commercial scale development commences and key infrastructure is in place.

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

RESERVES AND FINDING AND DEVELOPMENT COSTS (2)

Paramount's P+P reserves increased 5% to 662 MMBoe in 2021 compared to 632 MMBoe in 2020. TP and PDP reserves increased 9% and 4%, respectively. The growth in reserves was disproportionately liquids weighted, with a meaningful increase in condensate and NGLs volumes across all reserve categories.

In the Grande Prairie Region, where the majority of 2021 development activity occurred and the Company achieved further reductions in its cost structure, P+P reserves were up 8%, TP reserves were up 2% and PDP reserves were up 20%.

Paramount achieved strong F&D costs and recycle ratios in 2021 due to lower DCET costs across major resource plays and higher netbacks.(3)

Reserves by Product

Paramount's strategy to grow high value liquids reserves in its Montney and Duvernay resource plays is reflected by an increase of 16% in TP NGLs reserves and 15% in P+P NGLs reserves, while maintaining gas reserves volumes. Total liquids percentage increased to 49% from 46% for TP reserves and to 49% from 47% for P+P reserves. Total Company gross reserves at December 31, 2021 and 2020 are as follows:

	Proved			**Proved plus Probable**		
	2021	2020	*% Change*	**2021**	2020	*% Change*
Natural gas (Bcf)	**1,034.0**	1,014.4	*2*	**2,009.9**	1,994.3	*1*
NGLs (MBbl)	**146,264**	126,080	*16*	**296,918**	258,217	*15*
Crude oil (MBbl)	**20,881**	16,176	*29*	**30,561**	41,431	*(26)*
Total (MBoe)	**339,476**	311,317	*9*	**662,469**	632,025	*5*

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 10% and liquids sales volumes are lower by approximately 9% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See "Oil and Gas Measures and Definitions" in the Advisories section.

(2) Readers are referred to the advisories concerning "Reserves Data". Reserves evaluated by McDaniel and Associates Consultants Ltd. ("McDaniel") as of December 31, 2021 and December 31, 2020 in accordance with National Instrument 51-101 definitions, standards and procedures. Working interest reserves before royalty deductions. Net present values of future net revenue were determined using forecast prices and costs and do not represent fair market value. Readers should refer to the Company's annual information form for the year ended December 31, 2021, which is available on SEDAR at www.sedar.com, for a complete description of the reserves evaluation prepared by McDaniel for 2021 (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.

(3) "Finding and development costs" and "Recycle ratio" are non-GAAP ratios. Netback is a non-GAAP financial measure. Refer to the "Specified Financial Measures" section and "Oil and Gas Measures and Definitions" in the Advisories section for more information on these measures.

Reserves by Category

The following table summarizes the Company's gross proved and proved plus probable developed reserves and undeveloped reserves as at December 31, 2021 and the net present value of future net revenue of these reserves before income taxes, undiscounted and discounted at 10%.

	Proved [(1)]			Proved plus Probable [(1)]		
	Gross Reserves	Future Net Revenue NPV Before Tax ($ millions)		Gross Reserves	Future Net Revenue NPV Before Tax ($ millions)	
	(MBoe)	0%	10%	(MBoe)	0%	10%
Developed	125,008	1,049	1,436	169,419	1,922	1,872
Undeveloped	214,468	4,251	2,136	493,050	10,303	4,363
Total	**339,476**	**5,300**	**3,573**	**662,469**	**12,225**	**6,235**

(1) Columns may not add due to rounding. Net present values of future net revenue were determined using forecast prices and costs and do not represent fair market value.

Reserves Reconciliation

The reserves reconciliation highlights Paramount's strong replacement of production volumes, particularly with respect to liquids. Additions to TP liquids reserves represented 289% of liquids production and additions to P+P liquids reserves represented 311% of liquids production. Additions to TP gas reserves represented 120% of gas production and additions to P+P gas reserves represented 116% gas of production.

The following table provides a summary reconciliation of Paramount's gross reserves for the year ended December 31, 2021. Readers should refer to the information under the heading "Reserves and Other Oil and Gas Information – Reserves Reconciliation" in the Company's annual information form for the year ended December 31, 2021, which is available on www.sedar.com or at www.paramountres.com, for additional information, including reserves by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

	Proved [(1)]			Proved plus Probable [(1)]		
	Natural Gas	Liquids	Total	Natural Gas	Liquids	Total
	(Bcf)	(MBbl)	(MBoe)	(Bcf)	(MBbl)	(MBoe)
December 31, 2020	**1,014.4**	**142,256**	**311,317**	**1,994.3**	**299,648**	**632,025**
Extensions/Improved recovery	154.4	35,270	61,007	251.4	45,814	87,722
Technical revisions	(3.2)	2,887	2,375	(80.0)	(4,421)	(17,717)
Economic factors	43.1	2,337	9,512	57.0	3,271	12,767
Dispositions	(74.3)	(2,415)	(14,806)	(112.5)	(3,644)	(22,398)
Production	(100.4)	(13,190)	(29,930)	(100.4)	(13,190)	(29,930)
December 31, 2021	**1,034.0**	**167,145**	**339,476**	**2,009.9**	**327,478**	**662,469**

(1) Columns and rows may not add due to rounding.

Finding and Development Costs and Recycle Ratios [1]

The following table set out the Company's F&D costs and recycle ratios for the year ended December 31, 2021:

	F&D Capital [2]	Reserve Additions [3]	F&D	Recycle Ratio [4]
	($ millions)	(MMBoe)	($/Boe)	*(x)*
TOTAL COMPANY				
Proved Developed Producing	257	41.3	**6.22**	4.3x
Proved	490	72.9	**6.72**	4.0x
Proved plus Probable	176	82.8	**2.12**	12.6x
GRANDE PRAIRIE REGION				
Proved Developed Producing	207	31.7	**6.53**	5.1x
Proved	47	23.5	**1.99**	16.8x
Proved plus Probable	31	52.5	**0.59**	56.2x

(1) "Finding and development costs" and "Recycle ratio" are non-GAAP ratios. Refer to the "Specified Financial Measures" section and "Oil and Gas Measures and Definitions" in the Advisories section for more information on these measures.
(2) F&D capital is a non-GAAP financial measure. Refer to the "Specified Financial Measures" section for more information on this measure, including the calculation of F&D capital.
(3) Net changes to reserves from the prior year from extensions/improved recoveries, technical revisions and economic factors.
(4) Recycle ratio is calculated by dividing netback per Boe by the applicable finding and development cost.

LAND

Paramount's land position includes:

	December 31, 2021		December 31, 2020	
(thousands of acres)	**Gross** [1]	**Net** [2]	Gross [1]	Net [2]
Acreage assigned reserves	**653**	**514**	868	553
Acreage not assigned reserves	**1,995**	**1,126**	2,583	1,477
Total	**2,648**	**1,640**	3,451	2,030

(1) Gross acres means the total acreage in which Paramount has an interest. Gross acreage is calculated only once per lease or license of petroleum and natural gas rights ("Lease") regardless of whether or not Paramount holds a working and/or royalty interest, or whether or not the Lease includes multiple prospective formations. If Paramount holds interests in different formations beneath the same surface location pursuant to separate Leases, the acreage set out in each Lease is counted. Excludes Cavalier Energy lands.
(2) Net acres means gross acres multiplied by Paramount's working interest therein. Excludes Cavalier Energy lands.

Product Type Information
This document 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. See the Product Type Information section at page 108 of this document for a complete breakdown of sales volumes for applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Specified Financial Measures
This document includes references to certain non-GAAP financial measures, non-GAAP ratios, capital management measures used by Paramount and supplementary financial measures. Readers are referred to the Specified Financial Measures section at page 109 of this document for important additional information concerning these measures.

Advisories
Readers are referred to the Advisories section at page 113 of this document for important information and advisories respecting Forward-Looking Information, Reserves Data and Oil and Gas Measures and Definitions.

Management's Discussion and Analysis
For the year ended December 31, 2021

This Management's Discussion and Analysis ("MD&A"), dated March 1, 2022 should be read in conjunction with the audited consolidated financial statements of Paramount Resources Ltd. ("Paramount" or the "Company") as at and for the year ended December 31, 2021 (the "Consolidated Financial Statements"). Financial data included in this MD&A has been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") and is stated in millions of Canadian dollars, unless otherwise noted. The Company's accounting policies have been applied consistently to all periods presented. Certain comparative figures have been reclassified to conform to the current years' presentation.

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. Paramount's principal properties are located in Alberta and British Columbia. Paramount commenced operations as a public company in 1978 and has adapted to a multitude of operating and economic climates over the years. The Company's Class A common shares ("Common Shares") are listed on the Toronto Stock Exchange under the symbol "POU". Additional information concerning Paramount, including its Annual Information Form, can be found on the SEDAR website at www.sedar.com.

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

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

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

SPECIFIED FINANCIAL MEASURES, PRODUCT TYPES AND OTHER ADVISORIES

This MD&A includes references to: (i) "netback" and "netback including risk management contract settlements", which are non-GAAP financial measures; (ii) certain non-GAAP ratios; (iii) "adjusted funds flow", "net debt", "net debt to adjusted funds flow" and "free cash flow", which are capital management measures; and (iv) certain supplementary financial measures. Readers are referred to the Specified Financial Measures section of this MD&A for important additional information concerning these measures.

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

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

The disclosures in this MD&A include forward-looking information and certain oil and gas measures. Readers are referred to the Advisories section of this MD&A concerning such matters.

FINANCIAL AND OPERATING HIGHLIGHTS

	2021	2020	2019
FINANCIAL			
Petroleum and natural gas sales	1,383.0	626.0	914.9
Net income (loss)	236.9	(22.7)	(87.9)
Per share – basic ($/share)	1.77	(0.17)	(0.67)
Per share – diluted ($/share)	1.67	(0.17)	(0.67)
Cash from operating activities	482.1	80.9	255.7
Per share – basic ($/share) (1)	3.61	0.61	1.96
Per share – diluted ($/share) (1)	3.39	0.61	1.96
Adjusted funds flow (1)	499.8	150.0	299.0
Per share – basic ($/share)	3.74	1.12	2.29
Per share – diluted ($/share)	3.51	1.12	2.29
Free cash flow (1)	191.8	(113.7)	(137.9)
Per share – basic ($/share)	1.44	(0.85)	(1.06)
Per share – diluted ($/share)	1.36	(0.85)	(1.06)
Total assets	3,885.1	3,497.0	3,531.3
Long-term debt	386.3	813.5	632.3
Net debt (1)	456.7	854.1	703.5
Total liabilities	1,278.7	1,459.2	1,448.1
Common shares outstanding (millions) (2)	139.2	132.3	133.3
OPERATIONAL			
Sales volumes			
Natural gas (MMcf/d)	275.2	248.7	303.3
Condensate and oil (Bbl/d)	30,989	22,565	25,079
Other NGLs (Bbl/d)	5,147	4,325	6,767
Total (Boe/d)	82,001	68,340	82,394
Realized prices (1)			
Natural gas ($/Mcf)	3.72	2.25	2.36
Condensate and oil ($/Bbl)	81.91	46.47	66.66
Other NGLs ($/Bbl)	41.84	15.63	15.24
Petroleum and natural gas sales ($/Boe)	46.21	25.03	30.42
Capital expenditures	274.6	220.2	396.5

(1) Adjusted funds flow, free cash flow and net debt are capital management measures used by Paramount. Each measure, other than net income (loss), presented on a per share, $/Bbl, $/Mcf or $/Boe basis is a supplementary financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures. Prior period free cash flow results have been reclassified to conform with the current years' presentation.

(2) Common Shares are presented net of shares held in trust under the Company's restricted share unit plan (Common Shares): 2021: 1.5 million; 2020: 1.9 million; 2019: 0.9 million.

2021 OVERVIEW

Through solid operational performance and the disciplined execution of its capital program, Paramount successfully leveraged a significantly improved commodity price environment in 2021 to deliver strong financial and operating results that include:

- Average sales volumes of 82,001 Boe/d (44% liquids), an increase of 20 percent compared to 2020
- The achievement of targeted plateau production at Karr of approximately 40,000 Boe/d for the first time
- Operating costs that averaged $11.37/Boe, a 4 percent decrease compared to 2020 (1)
- Transportation and NGLs processing expense that averaged $3.83/Boe, a 5 percent decrease compared to 2020 (1)
- Cash from operating activities of $482.1 million, an increase of 496 percent compared to 2020
- Adjusted funds flow of $499.8 million, an increase of 233 percent compared to 2020
- Capital expenditures of $274.6 million, $15.4 million less than the midpoint of previous guidance provided on November 4, 2021
- Free cash flow of $191.8 million compared to ($113.7) million in 2020
- The implementation of a regular monthly dividend of $0.02 per Common Share in July that was subsequently tripled to $0.06 per Common Share in November
- Non-core property dispositions generating aggregate proceeds of $165.5 million
- A $397.4 million year-over-year reduction in net debt to $456.7 million at December 31, 2021

Sales volumes averaged 82,001 Boe/d (44% liquids) in 2021 compared to 68,340 Boe/d (39% liquids) in 2020. Sales volumes at Karr averaged 38,381 Boe/d (53% liquids) in 2021 compared to 20,777 Boe/d (55% liquids) in 2020. Sales volumes at Wapiti averaged 13,432 Boe/d (61% liquids) in 2021 compared to 10,207 Boe/d (64% liquids) in 2020. The increase in annual production was mainly the result of production from new wells brought onstream towards the end of 2020 and during 2021. Average sales volumes in 2021 were in-line with previous guidance provided on November 4, 2021 of approximately 82,000 Boe/d (44% liquids).

Capital expenditures in 2021, which were focused on drilling and completion activities at Karr, Wapiti and the Willesden Green Duvernay, totaled $274.6 million, $15.4 million less than the midpoint of previous guidance provided on November 4, 2021 due to a continued focus on strong execution and cost control. The Company achieved lower costs in its 2021 Karr and Wapiti drilling and completion programs despite emerging industry cost inflation, in part, by utilizing its wholly-owned Fox Drilling rigs and crews and securing fixed rates with certain service providers.

Crude oil and condensate prices continued to strengthen significantly through 2021 as the global economy and energy demand recover from the COVID-19 pandemic and supply increases remain tempered. Paramount also benefited from significant increases in natural gas prices.

Cash from operating activities was $482.1 million in 2021 compared to $80.9 million in 2020. Adjusted funds flow was $499.8 million in 2021 compared to $150.0 million in 2020. Free cash flow was $191.8

(1) Operating costs and transportation and NGLs processing expense, on a $/Boe basis, are supplementary financial measures. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures.

million in 2021 compared to ($113.7) million in 2020. Free cash flow was $23.2 million less than previous guidance provided on November 4, 2021 mainly as a result of lower than forecast commodity prices in the fourth quarter of 2021.

The free cash flow generated in 2021, along with proceeds of dispositions, was allocated to: (i) the reduction of indebtedness, contributing to a $397.4 million reduction in net debt to $456.7 million, (ii) the payment of an aggregate of $27.4 million in dividends and (iii) the repurchase for cancellation of 197,500 Common Shares under the Company's normal course issuer bid ("NCIB"). 2021 year-end net debt to adjusted funds flow was 0.9x versus previous guidance provided on November 4, 2021 of 0.8x.[(2)] See "Free Cash Flow Priorities" and "Liquidity and Capital Resources" in this MD&A.

Paramount continues to monitor the effect of the COVID-19 pandemic on its supply chain and the availability and cost of materials and third-party services. To date, the Company has not experienced a material interruption in supplies or services related to the pandemic, but has begun to observe emerging inflationary pressures that have the potential to impact future operating and capital costs. Commodity prices and economic conditions, including the potential for supply chain disruptions and inflation, remain, in part, dependent on the course of the COVID-19 pandemic and the response thereto. The Company continues to proactively respond to the pandemic and the risks that it poses, including the risks described in this MD&A under "Risk Factors".

UPDATED 2022 GUIDANCE

The Company's planned 2022 capital expenditures remain unchanged at a range of between $500 million and $540 million, with anticipated efficiency gains offsetting certain inflationary pressures. 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 is increasing its 2022 annual production guidance to average between 91,000 Boe/d and 95,000 Boe/d (46% liquids) to reflect the impact of the recently completed acquisition in the Grande Prairie Region described under "Capital Expenditures and Land and Property Acquisitions" in this MD&A. Although production in early 2022 at Wapiti was affected by two unplanned outages totaling 18 days at the third-party operated Wapiti natural gas processing facility, well outperformance is anticipated to offset this unplanned downtime.

- First half 2022 sales volumes are still expected to average between 81,000 Boe/d and 85,000 Boe/d (44% liquids), taking into account a planned 16-day full field outage at Karr during the second quarter for turnaround activities at third-party midstream facilities.

- Second half 2022 sales volumes are now expected to average between 101,000 Boe/d and 105,000 Boe/d (47% liquids) as numerous new wells from the Company's capital program are brought onstream.

Paramount is increasing its forecast of 2022 free cash flow from approximately $455 million to approximately $590 million to reflect higher commodity price assumptions and higher forecast production. The updated 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 expense, (iv) realized pricing of $61.95/Boe (US$86.30/Bbl WTI, US$4.74/MMBtu NYMEX, $4.25/GJ AECO), (v) royalties of $9.45/Boe, (vi) operating costs of $11.15/Boe, (vii) transportation and processing costs of $3.75/Boe and (viii) a $US/$Cdn exchange rate of $0.788.

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(1) Net debt to adjusted funds flow is a capital management measure used by Paramount. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure.

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

UPDATED 2023 PRELIMINARY GUIDANCE

Paramount's anticipated 2023 capital expenditure budget, based on preliminary planning and current market conditions, remains unchanged at a range of between $475 million and $525 million.

Paramount expects that a capital program in this range will result in 2023 average sales volumes of between 98,500 Boe/d and 103,500 Boe/d (48% liquids), 1,000 Boe/d higher than previously estimated.

Paramount is updating its estimate of 2023 free cash flow that would be expected from such a capital program from approximately $450 million to approximately $580 million to reflect higher commodity price assumptions and higher estimated production. This 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 net abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $54.60/Boe (US$76.96/Bbl WTI, US$3.84/MMBtu NYMEX, $3.39/GJ AECO), (v) royalties of $8.55/Boe, (vi) operating costs of $10.65/Boe, (vii) transportation and processing costs of $3.65/Boe and (viii) a $US/$Cdn exchange rate of $0.787.

FREE CASH FLOW PRIORITIES

As previously disclosed, the Company's free cash flow priorities are: (i) the achievement of targeted leverage levels, (ii) shareholder returns and (iii) incremental growth.

- The Company is targeting a leverage level of approximately $300 million in net debt. The Company expects to achieve this target in the third quarter of 2022 based on its 2022 free cash flow forecast.
- Remaining 2022 free cash flow will be available to:
    - further augment shareholder returns through additional increases in the regular monthly dividend, special dividends or opportunistic repurchases of Common Shares under the NCIB; and
    - reinvest in incremental organic growth or strategic acquisitions.

Paramount has hedged approximately 33 percent of its 2022 midpoint forecast production to provide greater free cash flow certainty. See "Operating Results – Risk Management Contracts".

CONSOLIDATED RESULTS

Net Income (Loss)

Paramount recorded net income of $236.9 million for the year ended December 31, 2021 compared to a net loss of $22.7 million for the year ended December 31, 2020. Significant factors contributing to the change are shown below:

Year ended December 31	
Net loss – 2020	**(22.7)**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	604.8
• Gain on the sale of oil and gas assets in 2021 compared to a loss in 2020	80.8
• Settlements in 2021	7.0
• Lower interest and financing expense in 2021	6.6
• Loss on risk management contracts in 2021 compared to a gain in 2020	(198.7)
• Higher depletion, depreciation and net impairment reversals in 2021	(112.3)
• Higher income tax expense in 2021	(75.4)
• Loss on settlement of dissent payment entitlement in 2021	(22.6)
• Higher provisions in 2021	(19.3)
• Higher general and administrative expense in 2021, mainly due to the receipt of benefits in 2020 under the Canada Emergency Wage Subsidy ("CEWS") program	(8.7)
• Other	(2.6)
Net income – 2021	**236.9**

Paramount recorded a net loss of $22.7 million for the year ended December 31, 2020 compared to a net loss of $87.9 million for the year ended December 31, 2019. Significant factors contributing to the change are shown below:

Year ended December 31	
Net loss – 2019	**(87.9)**
• Lower depletion, depreciation and net impairment reversals in 2020, mainly due to net impairment reversals of $141.9 million and lower depletion expense in 2020	236.7
• Lower income tax expense in 2020	102.1
• Gain on risk management contracts in 2020 compared to a loss in 2019	54.1
• Lower general and administrative expense in 2020	19.7
• Closure program costs recognized in 2019	14.0
• Lower accretion expense on asset retirement obligations in 2020	13.3
• Lower netback in 2020, mainly due to lower commodity prices and sales volumes, partially offset by lower operating expense	(184.6)
• Loss on the sale of oil and gas assets in 2020 compared to a gain in 2019	(178.0)
• Higher interest and financing expense in 2020	(13.5)
• Other	1.4
Net loss – 2020	**(22.7)**

Cash From Operating Activities

Cash from operating activities for the year ended December 31, 2021 was $482.1 million compared to $80.9 million for the year ended December 31, 2020. Significant factors contributing to the change are shown below:

Year ended December 31	
Cash from operating activities – 2020	**80.9**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	604.8
• Change in non-cash working capital	50.6
• Lower interest and financing expense in 2021	10.9
• Lower asset retirement obligations settled in 2021	9.6
• Settlements in 2021	7.0
• Payments on risk management contract settlements in 2021 compared to receipts in 2020	(255.9)
• Higher provisions in 2021	(19.3)
• Higher general and administrative expense in 2021, mainly due to the receipt of benefits in 2020 under the CEWS program	(8.7)
• Other	2.2
Cash from operating activities – 2021	**482.1**

Cash from operating activities for the year ended December 31, 2020 was $80.9 million compared to $255.7 million for the same period in 2019. Significant factors contributing to the change are shown below:

Year ended December 31	
Cash from operating activities – 2019	**255.7**
• Lower netback in 2020, mainly due to lower commodity prices and sales volumes, partially offset by lower operating expense	(184.6)
• Change in non-cash working capital	(33.8)
• Higher interest and financing expense in 2020	(12.3)
• Higher asset retirement obligations settled in 2020	(5.6)
• Higher receipts on risk management contract settlements in 2020	24.4
• Lower general and administrative expense in 2020	19.7
• Closure program costs recognized in 2019	14.0
• Other	3.4
Cash from operating activities – 2020	**80.9**

Adjusted Funds Flow [1]

The following is a reconciliation of adjusted funds flow to cash from operating activities, the most directly comparable measure disclosed in the primary financial statements of the Company:

Year ended December 31	2021	2020	2019
Cash from operating activities	482.1	80.9	255.7
Change in non-cash working capital [2]	(32.7)	17.9	(15.9)
Geological and geophysical expense [3]	8.0	8.5	11.0
Asset retirement obligations settled [2]	25.4	35.0	29.4
Closure costs [4]	–	–	14.0
Provisions [5]	24.0	4.7	–
Settlements [5]	(7.0)	–	2.5
Transaction and reorganization costs [6]	–	3.0	2.3
Adjusted funds flow	499.8	150.0	299.0
Adjusted funds flow (*$/Boe*) [7]	16.70	6.00	9.94

(1) Adjusted funds flow is a capital management measure used by Paramount. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure.
(2) Refer to the "Consolidated Statements of Cash Flows" in the Consolidated Financial Statements.
(3) Refer to Note 4 in the Consolidated Financial Statements.
(4) Refer to the "Consolidated Statements of Comprehensive Loss" in the Company's consolidated financial statements as at and for the year ended December 31, 2019.
(5) Refer to Note 16 in the Consolidated Financial Statements.
(6) Refer to the "Consolidated Statements of Comprehensive Income (Loss)" in the Consolidated Financial Statements.
(7) Adjusted funds flow ($/Boe) is a supplementary financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information.

Adjusted funds flow for the year ended December 31, 2021 was $499.8 million compared to $150.0 million for the year ended December 31, 2020. Significant factors contributing to the change are shown below:

Year ended December 31	
Adjusted funds flow – 2020	**150.0**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	604.8
• Lower interest and financing expense in 2021	10.9
• Payments on risk management contract settlements in 2021 compared to receipts in 2020	(255.9)
• Higher general and administrative expense in 2021, mainly due to the receipt of benefits in 2020 under the CEWS program	(8.7)
• Other	(1.3)
Adjusted funds flow – 2021	**499.8**

Adjusted funds flow for the year ended December 31, 2020 was $150.0 million compared to $299.0 million for the year ended December 31, 2019. Significant factors contributing to the change are shown below:

Year ended December 31	
Adjusted funds flow – 2019	**299.0**
• Lower netback in 2020, mainly due to lower commodity prices and sales volumes, partially offset by lower operating expense	(184.6)
• Higher interest and financing expense in 2020	(12.3)
• Higher receipts on risk management contract settlements in 2020	24.4
• Lower general and administrative expense in 2020	19.7
• Other	3.8
Adjusted funds flow – 2020	**150.0**

Free Cash Flow [1]

The following is a reconciliation of free cash flow to cash from operating activities, the most directly comparable measure disclosed in the primary financial statements of the Company:

Year ended December 31	2021	2020 (1)	2019 (1)
Cash from operating activities	**482.1**	80.9	255.7
Change in non-cash working capital (2)	**(32.7)**	17.9	(15.9)
Geological and geophysical expense (3)	**8.0**	8.5	11.0
Asset retirement obligations settled (2)	**25.4**	35.0	29.4
Closure costs (4)	**–**	–	14.0
Provisions (5)	**24.0**	4.7	–
Settlements (5)	**(7.0)**	–	2.5
Transaction and reorganization costs (6)	**–**	3.0	2.3
Adjusted funds flow	**499.8**	150.0	299.0
Capital expenditures (2)	**(274.6)**	(220.2)	(396.5)
Geological and geophysical expense (3)	**(8.0)**	(8.5)	(11.0)
Asset retirement obligations settled (2)	**(25.4)**	(35.0)	(29.4)
Free cash flow	**191.8**	(113.7)	(137.9)

(1) Free cash flow is a capital management measure used by Paramount. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure. Prior period results have been updated to reflect the current period presentation.
(2) Refer to the "Consolidated Statements of Cash Flows" in the Consolidated Financial Statements.
(3) Refer to Note 4 in the Consolidated Financial Statements.
(4) Refer to the "Consolidated Statements of Comprehensive Loss" in the Company's consolidated financial statements as at and for the year ended December 31, 2019.
(5) Refer to Note 16 in the Consolidated Financial Statements.
(6) Refer to "Consolidated Statements of Comprehensive Income (Loss)" in the Consolidated Financial Statements.

Free cash flow for the year ended December 31, 2021 was $191.8 million compared to ($113.7) million for the year ended December 31, 2020. Significant factors contributing to the change are shown below:

Year ended December 31	
Free cash flow – 2020	**(113.7)**
• Change in adjusted funds flow (described in "Adjusted Funds Flow" section above)	349.8
• Lower asset retirement obligations settled in 2021	9.6
• Lower geological and geophysical expense in 2021	0.5
• Higher capital expenditures in 2021	(54.4)
Free cash flow – 2021	**191.8**

Free cash flow for the year ended December 31, 2020 was ($113.7) million compared to ($137.9) million for the same period in 2019. Significant factors contributing to the change are shown below:

Year ended December 31	
Free cash flow – 2019	**(137.9)**
• Lower capital expenditures in 2020	176.3
• Lower geological and geophysical expense in 2020	2.5
• Change in adjusted funds flow (described in "Adjusted Funds Flow" section above)	(149.0)
• Higher asset retirement obligations settled in 2020	(5.6)
Free cash flow – 2020	**(113.7)**

OPERATING RESULTS

Netback [(1)]

Year ended December 31	2021		2020	
		($/Boe) [(2)(3)]		($/Boe) [(2)(3)]
Natural gas revenue [(4)]	**373.3**	***3.72***	204.9	*2.25*
Condensate and oil revenue [(4)]	**926.5**	***81.91***	383.8	*46.47*
Other NGLs revenue [(4)]	**78.6**	***41.84***	24.7	*15.63*
Royalty and other revenue [(4)]	**4.6**	***–***	12.6	*–*
Petroleum and natural gas sales [(5)]	**1,383.0**	***46.21***	626.0	*25.03*
Royalties [(5)]	**(127.0)**	***(4.24)***	(31.3)	*(1.25)*
Operating expense [(5)]	**(340.4)**	***(11.37)***	(297.1)	*(11.88)*
Transportation and NGLs processing [(5)]	**(114.5)**	***(3.83)***	(101.3)	*(4.05)*
Netback	**801.1**	***26.77***	196.3	*7.85*
Risk management contract settlements [(6)]	**(218.3)**	***(7.29)***	37.6	*1.50*
Netback including risk management contract settlements [(7)]	**582.8**	***19.48***	233.9	*9.35*

(1) Netback is a non-GAAP financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure.
(2) Natural gas revenue shown per Mcf.
(3) When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure and Netback and Netback including risk management contract settlements are non-GAAP ratios. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures.
(4) Refer to Note 15 in the Consolidated Financial Statements.
(5) Refer to "Consolidated Statements of Comprehensive Income (Loss)" in the Consolidated Financial Statements.
(6) Refer to Note 14 in the Consolidated Financial Statements.
(7) Netback including risk management contract settlements is a non-GAAP financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure.

Petroleum and natural gas sales were $1,383.0 million in 2021, an increase of $757.0 million from the prior year mainly due to higher commodity prices and sales volumes.

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

	Natural gas	Condensate and oil	Other NGLs	Royalty and other	Total
Year ended December 31, 2020	204.9	383.8	24.7	12.6	626.0
Effect of changes in realized prices	147.2	400.9	49.3	–	597.4
Effect of changes in sales volumes	21.2	141.8	4.6	–	167.6
Change in royalty and other revenue	–	–	–	(8.0)	(8.0)
Year ended December 31, 2021	**373.3**	**926.5**	**78.6**	**4.6**	**1,383.0**

Petroleum and natural gas sales were $626.0 million in 2020, a decrease of $288.9 million from 2019 mainly due to lower commodity prices and sales volumes.

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

	Natural gas	Condensate and oil	Other NGLs	Royalty and other	Total
Year ended December 31, 2019	261.0	610.2	37.7	6.0	914.9
Effect of changes in realized prices	(9.7)	(166.7)	0.5	–	(175.9)
Effect of changes in sales volumes	(46.4)	(59.7)	(13.5)	–	(119.6)
Change in royalty and other revenue	–	–	–	6.6	6.6
Year ended December 31, 2020	**204.9**	**383.8**	**24.7**	**12.6**	**626.0**

Sales Volumes [1]

	Year ended December 31											
	Natural gas (MMcf/d)			Condensate and oil (Bbl/d)			Other NGLs (Bbl/d)			Total (Boe/d)		
	2021	2020	% Change	2021	2020	% Change	2021	2020	% Change	2021	2020	% Change
Grande Prairie	**141.0**	78.6	*79*	**25,258**	16,005	*58*	**3,103**	1,964	*58*	**51,869**	31,076	*67*
Kaybob	**97.2**	125.9	*(23)*	**4,779**	5,895	*(19)*	**1,612**	1,812	*(11)*	**22,588**	28,685	*(21)*
Central Alberta and Other	**37.0**	44.2	*(16)*	**952**	665	*43*	**432**	549	*(21)*	**7,544**	8,579	*(12)*
Total	**275.2**	248.7	*11*	**30,989**	22,565	*37*	**5,147**	4,325	*19*	**82,001**	68,340	*20*

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

Sales volumes were 82,001 Boe/d for the year ended December 31, 2021, compared to 68,340 Boe/d in the same period in 2020. The Company focused its capital program in 2020 and 2021 on its developments at Karr and Wapiti, which resulted in higher 2021 sales volumes in the liquids rich Grande Prairie Region and lower sales volumes in the Kaybob Region due to declines.

At Karr, 2021 sales volumes were 38,381 Boe/d (53% liquids) compared to 20,777 Boe/d (55% liquids) in 2020. The increase resulted from development activities where Paramount brought 19 new wells on production in 2021 in addition to 10 new wells brought onstream in the last four months of 2020. The Company's 2022 capital plan for Karr is focused on development and debottlenecking operations in support of growing production to 43,000 to 47,000 Boe/d in the second half of the year.

Sales volumes at Wapiti increased to 13,432 Boe/d (61% liquids) in 2021 compared to 10,207 Boe/d (64% liquids) in 2020. The increase mainly resulted from development activities where the Company brought 10 new wells on production in 2021 in addition to five new wells brought onstream in the fourth quarter of 2020. Production at Wapiti in 2021 was impacted by planned and unplanned outages at the third-party Wapiti natural gas processing facility (the "Wapiti Plant") totaling approximately three weeks (approximately ten weeks of outages in 2020). The Company has increased development activities at Wapiti in 2022 to drill 32 Montney wells and bring onstream 23 Montney wells in support of increasing production at Wapiti to approximately 27,000 Boe/d by the end of 2022.

Sales volumes in 2021 were also lower by approximately 2,600 Boe/d (14.8 MMcf/d of conventional natural gas and 134 Bbl/d of NGLs) in the Kaybob Region and approximately 1,000 Boe/d (4.6 MMcf/d of shale gas and 273 Bbl/d of NGLs) in the Central Alberta and Other Region compared to 2020 due to non-core dispositions completed in 2021.

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

In the first quarter of 2021, the Company sold certain properties in the Kaybob and Central Alberta and Other Regions for proceeds of approximately $79 million. These assets had average sales volumes of approximately 2,700 Boe/d (15.4 MMcf/d of conventional natural gas and 142 Bbl/d of NGLs) and a netback of approximately $1 million in the fourth quarter of 2020, the last full quarter prior to sale.

Commodity Prices [1]

Year Ended December 31	2021	2020	% Change
Natural Gas			
Paramount realized natural gas price ($/Mcf)	3.72	2.25	*65*
AECO daily spot ($/GJ)	3.44	2.11	*63*
AECO monthly index ($/GJ)	3.38	2.12	*59*
Dawn ($/MMBtu)	4.55	2.51	*81*
NYMEX (US$/MMBtu)	3.72	2.13	*75*
Malin – monthly index (US$/MMBtu)	3.89	2.15	*81*
Condensate and Oil			
Paramount realized condensate & oil price ($/Bbl)	81.91	46.47	*76*
Edmonton light sweet crude oil ($/Bbl)	80.31	45.39	*77*
West Texas Intermediate crude oil (US$/Bbl)	67.91	39.40	*72*
Other NGLs			
Paramount realized Other NGLs price ($/Bbl)	41.84	15.63	*168*
Conway – propane ($/Bbl)	54.87	24.83	*121*
Belvieu – butane ($/Bbl)	61.83	30.48	*103*
Foreign Exchange			
$CDN / 1 $US	1.25	1.34	*(7)*

(1) Realized prices per Mcf and Bbl are supplementary financial measures. Refer to the "Specified Financial Measures" section of this MD&A for more information.

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

Realized natural gas prices in 2021 include the impact of approximately 102,000 GJ/d of natural gas sales under fixed-priced physical contracts at C$2.72/GJ (2020 – approximately 79,000 GJ/d of natural gas at C$1.90/GJ).

The Company had the following fixed-price and basis differential physical contracts at December 31, 2021:

	Volume	Location	Average price	Remaining term
Natural gas	40,000 GJ/d	AECO	CDN$4.06/GJ	January 2022 – March 2022
Natural gas	30,000 GJ/d	AECO	CDN$3.54/GJ	April 2022 – October 2022
Condensate	2,098 Bbl/d	FSPL [1]	WTI + US$3.13/Bbl	January 2022 – March 2022

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

Subsequent to December 31, 2021, the Company entered into the following fixed-price and basis differential physical contracts:

	Volume	Location	Average price	Remaining term
Natural gas	50,000 GJ/d	AECO	CDN$3.92/GJ	April 2022 – October 2022
Natural gas	20,000 MMBtu/d	Dawn	US$4.03/MMBtu	April 2022 – October 2022
Peace sweet crude oil	5,186 Bbl/d	Peace [1]	WTI – US$2.15/Bbl	April 2022 – June 2022

(1) Peace refers to the Peace Pipeline at Edmonton.

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

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

Risk Management Contracts

Commodity Contracts

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

Year ended December 31	2021	2020
Fair value, beginning of year	(22.7)	6.0
Changes in fair value	(190.1)	8.9
Settlements paid (received)	218.2	(37.6)
Fair value, end of year	**5.4**	(22.7)

For further details on the Company's financial commodity contracts, refer to Note 14 in the Consolidated Financial Statements.

Subsequent to December 31, 2021, the Company entered into the following financial commodity contracts:

Instruments	Aggregate notional	Average fixed price	Remaining term
Gas – NYMEX Swaps (Sale)	30,000 MMBtu/d	US$4.62/MMBtu	April 2022 – June 2022
Gas – NYMEX Swaps (Sale)	30,000 MMBtu/d	US$4.67/MMBtu	July 2022 – September 2022
Gas – NYMEX Swaps (Sale)	10,000 MMBtu/d	US$4.91/MMBtu	October 2022

The following table summarizes the Company's financial commodity and physical contracts at March 1, 2022:

	Type (1)	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Average Price (2)
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	3,500	3,500	3,500	3,500	US$75.79/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	9,500	–	–	–	CDN$87.90/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	3,500	3,500	3,500	CDN$91.38/Bbl
Oil – WTI Collars (Bbl/d)	Financial	7,000	7,000	7,000	7,000	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)
Condensate – Basis (Sale) (Bbl/d)	Physical	2,098	–	–	–	WTI + US$3.13/Bbl
Sweet Crude Oil – Basis (Sale) (Bbl/d)	Physical	–	5,186	–	–	WTI – US$2.15/Bbl
Gas – NYMEX Swaps (Sale) (MMBtu/d)	Financial	40,000	–	–	–	US$4.15/MMBtu
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	40,000	–	–	–	CDN$4.06/GJ
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

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

Foreign Currency Exchange Contracts

Paramount uses foreign currency exchange contracts from time-to-time to manage risks of volatility in foreign currency exchange related to its U.S. dollar denominated petroleum and natural gas sales revenue.

The Company had the following foreign currency exchange contracts at December 31, 2021:

Instruments	Aggregate notional	Average rate	Remaining term
Foreign Currency Exchange Swaps	US$5 million / month	1.27 C$ / US$1.00	January 2022 – December 2022
Foreign Currency Exchange Collars	US$5 million / month	1.25 C$ / US$1.00 (Floor) 1.30 C$ / US$1.00 (Ceiling)	January 2022 – November 2022

For further details on the Company's foreign currency exchange contracts, refer to Note 14 in the Consolidated Financial Statements.

Royalties

Year ended December 31	2021	Rate (1)	2020	Rate (1)
Royalties	127.0	9.2%	31.3	5.1%
$/Boe (1)	*4.24*		*1.25*	

(1) Royalty rate and royalties per Boe are supplementary financial measures. Refer to the "Specified Financial Measures" section of this MD&A for more information.

Royalties were $127.0 million for the year ended December 31, 2021, $95.7 million higher than the same period in 2020, primarily as a result of higher commodity prices and sales volumes. Royalty rates were higher at Karr as a greater proportion of wells have fully utilized new well royalty incentives.

Operating Expense

Year ended December 31	2021	2020	% Change
Operating expense	340.4	297.1	15
$/Boe (1)	11.37	11.88	(4)

(1) Operating expense per Boe is a supplementary financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information.

Operating expenses were $340.4 million for the year ended December 31, 2021 compared to $297.1 million in 2020. Operating costs in 2021 were higher compared to 2020 mainly due to higher production and processing fees in the Grande Prairie Region in 2021, equalizations totaling $6.7 million related to prior periods that reduced operating costs in 2020, $5.2 million in supplier cost reductions unique to the second quarter of 2020 and the receipt in 2020 of $4.0 million in benefits under the CEWS program.

These increases were partially offset by lower operating costs because of lower production in the Kaybob and Central Alberta and Other Regions and cost reductions from water disposal wells brought into service in the first half of 2020 in Karr.

Operating expense per Boe was $11.37 for the year ended December 31, 2021 compared to $11.88 per Boe in 2020, mainly due to the impact of higher production and the changes in costs described above. Paramount achieved operating costs at Karr of $9.57 per Boe in 2021, lower than targeted operating costs of $10.00 per Boe. Karr operating costs were $14.10 per Boe in 2020.

Transportation and NGLs Processing

Year ended December 31	2021	2020	% Change
Transportation and NGLs processing	114.5	101.3	13
$/Boe (1)	3.83	4.05	(5)

(1) Transportation and NGLs processing per Boe is a supplementary financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information.

Transportation and NGLs processing expense was $114.5 million for the year ended December 31, 2021 compared to $101.3 million in the same period in 2020. Transportation and NGLs processing costs increased in 2021 mainly as a result of higher production volumes at Karr and Wapiti, partially offset by lower production in the Kaybob and Central Alberta and Other Regions.

Other Items

Year ended December 31	2021	2020
Depletion and depreciation (excluding net impairment reversals)	(300.5)	(253.9)
Change in asset retirement obligations	(138.9)	86.8
ASRP funding	9.7	4.4
Net impairment reversals of property plant and equipment	296.6	141.9
Gain (loss) on sale of oil and gas assets	72.1	(8.7)
Exploration and evaluation expense	(38.9)	(34.0)

Depletion and depreciation expense increased to $300.5 million in 2021 compared to $253.9 million in 2020, mainly due to higher Grande Prairie Region sales volumes and higher depletion rates in the Kaybob CGU following impairment reversals recorded in the third quarter of 2021 and in the fourth quarter of 2020. These increases were partially offset by lower depletion rates in the Grande Prairie Region.

For the year ended December 31, 2021, the Company recorded a charge of $138.9 million to earnings (2020 – $86.8 million recovery) related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value. The changes mainly resulted from revisions in the credit-adjusted risk-free rate used to discount obligations.

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

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

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

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at September 30, 2021: (1)

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

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

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

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

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

Exploration and evaluation expense was $38.9 million in 2021, an increase of $4.9 million compared to $34.0 million in 2020, primarily due to higher expenses for expired mineral leases.

ASSET RETIREMENT OBLIGATIONS

Paramount's strategy is to utilize the advantages of the Alberta Energy Regulator's area-based closure program to advance its abandonment and reclamation activities in an efficient and cost-effective manner by targeting its efforts in concentrated areas. In 2021 and 2020, Paramount focused its activities in the Zama area, which was shut-in in 2019 and the Hawkeye area, which was shut-in in 2018.

Abandonment and reclamation expenditures in 2021 totaled $25.4 million, net of approximately $9.7 million in funding under the ASRP. Activities in 2021 included the abandonment of 156 wells, 137 of which were abandoned under the Company's ongoing area-based closure program at Zama.

The Company's budget for abandonment and reclamation activities in 2022 remains unchanged at approximately $41 million. Approximately $8 million is to be funded directly under the ASRP, resulting in approximately $33 million net to Paramount. The majority of 2022 activities will be performed at Zama.

As at December 31, 2021, estimated undiscounted, uninflated asset retirement obligations were $1,318.7 million (December 31, 2020 – $1,351.7 million). As at December 31, 2021, the Company's discounted asset retirement obligations were $651.1 million (discounted at 7.0 percent and using an inflation rate of 2.0 percent) compared to $419.5 million as at December 31, 2020 (discounted at 11.0 percent and using an inflation rate of 2.0 percent). For further details concerning the Company's asset retirement obligations, refer to the Consolidated Financial Statements.

OTHER ASSETS

Investments in Securities

As at December 31	2021	2020
Level one fair value hierarchy securities ("Level One Securities")	300.2	48.4
Level three fair value hierarchy securities ("Level Three Securities")	71.9	11.1
	372.1	59.5

Paramount holds investments in a number of publicly-traded and private corporations as part of its portfolio of investments. Investments that are categorized as Level One Securities are carried at their period-end trading prices. Estimates of fair values for investments that are categorized as Level Three Securities are based on valuation techniques that incorporate unobservable inputs. The valuation techniques utilize market-based metrics of comparable companies and transactions, indicators of value based on equity transactions of the entities and other indicators of value including financial and operating results of the entities. Fair value estimates of Level Three Securities are updated at each balance sheet date to confirm whether the carrying value of the investment continues to fall within a range of possible fair values indicated by such techniques.

For the year ended December 31, 2021, the Company recorded $316.8 million, before tax, to OCI as a result of changes in the fair value estimates of investments in securities.

In 2020, the Company acquired 17.3 million common shares of NuVista Energy Ltd. ("NuVista Shares") at a price of $0.61 per share for an aggregate purchase price of $10.6 million. At December 31, 2021, the Company owned a total of 39.8 million NuVista Shares having a carrying value of $276.7 million, which were included in Investments in Securities and classified as Level One Securities.

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

Year ended at December 31	2021	2020
Investments in securities, beginning of year	59.5	156.9
Changes in fair value of Level One Securities – recorded in OCI	256.0	(50.6)
Changes in fair value of Level Three Securities – recorded in OCI	60.8	32.5
Transfer to Dissent Payment Entitlement	–	(89.3)
Derecognition of warrants	(0.1)	–
Changes in fair value of warrants – recorded in earnings	0.1	(1.7)
Acquired	1.0	11.7
Proceeds of dispositions	(5.2)	–
Investments in securities, end of year	372.1	59.5

Dissent Payment Entitlement

As at December 31	2021	2020
Dissent Payment Entitlement	–	89.3

Paramount held 85 million common shares of Strath Resources Ltd. ("Strath") prior to its amalgamation with Cona Resources Ltd. in August 2020 to form Strathcona Resources Ltd. ("Strathcona"). Paramount objected to the amalgamation and exercised its right of dissent under section 191 of the *Business Corporations Act* (Alberta) with respect to its Strath shares. As a result, the Company became entitled to be paid in cash the fair value of its Strath shares determined as of the close of business on July 24, 2020 (the "Dissent Payment Entitlement"), which Paramount originally estimated to be $89.3 million. Paramount ultimately received $67 million cash in 2021 in settlement of the dissent proceedings and for the sale of its remaining securities in Strathcona. A loss of $22.6 million was recognized on the settlement. For additional information on the Dissent Payment Entitlement, refer to Note 6 in the Consolidated Financial Statements.

Fox Drilling

Fox Drilling owns seven triple-sized rigs, including four walking rigs, that are used to drill Company wells. The walking rigs have the capability of moving across a lease with the derrick and drill pipe remaining vertical, significantly increasing efficiencies when drilling multi-well pads. Five of the Fox Drilling rigs are bi-fuel capable, enabling the use of Company-produced natural gas to save costs and reduce emissions compared to diesel engines.

Cavalier Energy

As at December 31, 2021, Cavalier Energy held approximately 1.360 million gross (1.315 million net) acres of land located primarily in the Athabasca and Peace River regions of Alberta. Cavalier Energy's lands, which include 278,000 net acres with Clearwater and Bluesky potential, are prospective for in-situ thermal oil recovery and heavy oil but are not currently being developed. No reserves have been attributed to Cavalier Energy's lands and there are no assurances that Cavalier Energy will develop the properties, generate earnings, operate profitably or provide a return on investment in the future.

Other Strategic Investments

Paramount also holds approximately 103,000 gross (85,000 net) acres of undeveloped land in the Liard Basin in northeast British Columbia and the Northwest Territories prospective for natural gas production from the Besa River shale formation and approximately 483,000 gross (207,000 net) acres of undeveloped land in the Mackenzie Delta and Central Mackenzie in the Northwest Territories prospective for natural gas and oil production.

CORPORATE

Year ended December 31	2021	2020
General and administrative	(41.6)	(32.9)
Share-based compensation	(18.8)	(13.0)
Interest and financing	(47.1)	(53.7)
Accretion of asset retirement obligations	(42.6)	(43.4)
Loss on dissent payment entitlement	(22.6)	–
Deferred income tax expense	(85.6)	(10.2)

General and administrative expense was $41.6 million for the year ended December 31, 2021 compared to $32.9 million in 2020 mainly due to the impact of benefits received in 2020 under the CEWS program, which totaled $6.4 million.

Interest and financing expense was lower in 2021 compared to 2020 mainly as a result of lower average debt balances under the Company's bank credit facility.

A loss of $22.6 million was recognized on the settlement of the Dissent Payment Entitlement as described under "Other Assets – Dissent Payment Entitlement".

Tax Pools

The following table summarizes Paramount's tax pools at December 31, 2021:

As at December 31	($ billions)
Cumulative Canadian development expenses	0.6
Undepreciated capital cost	0.4
Non-capital loss and scientific, research and experimental development	3.4
Financing costs and other	0.2
Total	**4.6**

CAPITAL EXPENDITURES AND LAND AND PROPERTY ACQUISITIONS

Capital Expenditures

Year ended December 31	2021	2020
Drilling, completion, equipping and tie-ins	257.4	199.5
Facilities and gathering	11.0	18.4
Corporate	6.2	2.3
Capital expenditures	274.6	220.2
Grande Prairie Region	228.6	196.9
Kaybob Region	14.5	16.4
Central Alberta and Other Region	25.3	4.6
Corporate	6.2	2.3
Capital expenditures	274.6	220.2

Land and Property Acquisitions

Year ended December 31	2021	2020
Land and property acquisitions	5.4	0.6

Capital expenditures were $274.6 million for the year ended December 31, 2021 compared to $220.2 million in 2020. Expenditures in 2021 were mainly directed to drilling and completion programs in the Grande Prairie Region. Significant capital program activities undertaken in 2021 are described below:

- At Karr, the Company drilled 20 (20.0 net) wells and brought on production 19 (19.0 net) wells.
- At Wapiti, Paramount drilled 12 (12.0 net) wells and brought on production 10 (10.0 net) wells.
- In the Kaybob Region, the Company completed and brought on production 1 (1.0 net) oil well at Ante Creek and initiated an enhanced oil recovery pilot project on a portion of the Kaybob North Montney oil development to assess the viability of implementing the program across the field.
- In the Central Alberta and Other Region, Paramount drilled and brought on production 2 (2.0 net) wells at Willesden Green and drilled 1 (1.0 net) exploratory oil well in southern Alberta that was uneconomic and subsequently abandoned.

Capital expenditures of $274.6 million were $15.4 million less than the midpoint of previous guidance provided on November 4, 2021 mainly due to a continued focus on strong execution and cost control. The Company reduced average per well drilling, completion, equipping and tie-in costs in 2021 compared to 2020 by approximately 20 percent at Karr and 10 percent at Wapiti.

In the first quarter of 2022, the Company successfully closed a highly complementary acquisition in the Grande Prairie Region for $24.4 million. The acquisition is expected to contribute approximately 1,000 Boe/d to annual 2022 sales volumes.

LIQUIDITY AND CAPITAL RESOURCES

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

i. ensure liquidity to fund ongoing operations and capital programs, the settlement of obligations when due and the payment of regular monthly dividends;

ii. preserve financial flexibility and access to capital markets, including for the pursuit of strategic initiatives; and

iii. maximize shareholder returns considering the risk environment.

Paramount monitors and assesses its capital structure for alignment with its current and long-term business plans and will, guided by its primary capital management objectives, seek to adjust the structure as necessary in response to changes in its business plans, plans for shareholder returns, economic and operating conditions, financial and operating results, strategic initiatives and the Company's assessment of the risk environment. Paramount may adjust its capital structure through a number of means, including by modifying capital spending programs, seeking to issue or repurchase shares, altering debt levels, modifying dividend levels or acquiring or disposing of assets.

The key capital management measures used by the Company in monitoring and assessing its capital structure are net debt, adjusted funds flow, the ratio of net debt to adjusted funds flow and free cash flow. Paramount is targeting a leverage level of approximately $300 million in net debt. Based on its 2022 free cash flow forecast of $590 million, the Company expects to achieve this target in the third quarter of 2022, implying a net debt to adjusted funds flow ratio of less than 0.5x at the end of that quarter. These measures are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities.

As at December 31	2021	2020
Cash and cash equivalents	(1.7)	(4.6)
Accounts receivable [(1)]	(139.7)	(97.7)
Prepaid expenses and other	(7.3)	(9.9)
Accounts payable and accrued liabilities	219.1	152.8
Long-term debt	386.3	813.5
Net debt	**456.7**	854.1

(1) Accounts receivable excludes amounts relating to subleases (December 31, 2021 – $2.2 million, December 31, 2020 – $2.3 million).

Net debt does not account for the $372.1 million carrying value of the Company's investments in securities as at December 31, 2021.

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

Based on the forecasts of 2022 sales volumes and the pricing assumptions set out in this MD&A under "2022 Guidance", Paramount expects to fully fund budgeted 2022 capital expenditures and net budgeted expenditures for abandonment and reclamation activities from cash from operating activities. Paramount may utilize borrowing capacity under the Paramount Facility for liquidity from time to time to temporarily fund operations during periods should expenditures exceed cash from operating activities.

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

Paramount may also determine to divest of assets or investments in securities from time to time to reduce indebtedness or fund operations. In 2021, the Company sold certain non-core properties for aggregate proceeds of approximately $165 million and received $67 million cash in settlement of the Strath dissent process and for the sale of its remaining securities in Strathcona, and used such proceeds to reduce indebtedness under the Paramount Facility. Subject to market conditions and availability, proceeds from new debt and/or equity financings may also provide additional sources of capital from time to time. In January 2021, as described below under "Convertible Debentures", the Company completed a private placement of $35 million of senior unsecured convertible debentures and used the proceeds to reduce indebtedness under the Paramount Facility. In the fourth quarter of 2021, all debenture holders exercised their right to convert their convertible debentures into Common Shares. For further details see "Convertible Debentures" below.

Paramount Facility

The Company has a $900 million financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility"). The maturity date of the Paramount Facility is June 2, 2024. At Paramount's request, the credit limit of the Paramount Facility can be increased to $1.0 billion pursuant to an accordion feature in the facility, subject to incremental lender commitments.

Borrowings under the Paramount Facility bear interest at the prime lending rate, US base rate, CDOR, or LIBOR, as selected by the Company, plus an applicable margin which varies based on the Company's Senior Secured Debt to Consolidated EBITDA ratio. The Paramount Facility is secured by a charge over substantially all of the assets of the Company and its subsidiaries.

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

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

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

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

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

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

Paramount was in compliance with the financial covenants under the Paramount Facility at December 31, 2021.

The Company had undrawn letters of credit outstanding under the Paramount Facility totaling $2.3 million at December 31, 2021 that reduce the amount available to be drawn on the facility.

Unsecured Letter of Credit Facility

The Company has a $70 million unsecured demand revolving letter of credit facility (the "LC Facility") with a Canadian bank. Paramount's obligations under the LC Facility are supported by a performance security guarantee ("PSG") from Export Development Canada ("EDC"). The PSG is valid to June 30, 2022 and may be extended from time-to-time with the agreement of EDC. At December 31, 2021, $38.7 million in undrawn letters of credit were outstanding under the LC Facility (December 31, 2020 – $40.7 million).

Convertible Debentures

In January 2021, the Company completed a private placement of $35.0 million of senior unsecured convertible debentures (the "Convertible Debentures"). An entity controlled by Paramount's President and Chief Executive Officer and Chairman purchased $25.0 million of the Convertible Debentures. The Convertible Debentures had a maturity date of January 31, 2024 (the "Maturity Date"), bore interest at 7.50 percent per annum and were convertible by the holder into Common Shares at any time prior to the Maturity Date. On the issuance date of the Convertible Debentures, the conversion prices were $6.72 per Common Share prior to January 31, 2022, $7.33 per Common Share on or after January 31, 2022 and prior to January 31, 2023 and $7.94 per Common Share on or after January 31, 2023. These prices were subject to customary anti-dilution adjustments.

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

In November 2021, Paramount delivered notices to redeem all $35.0 million of the Convertible Debentures effective December 3, 2021 (the "Redemption Date"). Prior to the Redemption Date, all holders exercised their right to convert their Convertible Debentures into Common Shares. An aggregate of 5,249,019 Common Shares were issued on conversion of the debentures, including 3.8 million Common Shares issued on conversion of $25.0 million principal amount of debentures held by an entity controlled by Paramount's President and Chief Executive Officer and Chairman. For the year ended December 31, 2021, $2.2 million in interest payments were made on the Convertible Debentures.

Cash Flow Hedges

The Company had the following floating-to-fixed interest rate and electricity swaps at December 31, 2021:

Contract type	Aggregate notional	Remaining term	Average fixed contract rate	Reference	Fair value
Interest Rate Swaps	$250 million	January 2022 – January 2023	2.3%	CDOR (1)	**(3.2)**
Interest Rate Swaps	$250 million	January 2022 – January 2026	2.4%	CDOR (1)	**(6.4)**
Electricity Swaps	120 MWh/d (2)	January 2023 – December 2023	$62.50/MWh	AESO Pool Price (3)	**0.4**
Electricity Swaps	120 MWh/d (2)	January 2024 – December 2024	$53.25/MWh	AESO Pool Price (3)	**0.3**
					(8.9)

(1) Canadian Dollar Offered Rate.
(2) "MWh" means megawatt-hour.
(3) Floating hourly rate established by the Alberta Electric System Operator.

The Company has classified these arrangements as cash flow hedges and applied hedge accounting. At December 31, 2021, $150 million of floating-to-fixed interest rate swaps were de-designated as cash flow hedges due to declines in borrowings under the Paramount Facility, which resulted in a reclassification of $1.9 million of unrealized losses from other comprehensive income to interest and financing expense. There were no other changes to the critical terms of the hedging relationships and no hedge ineffectiveness was identified on the floating-to-fixed electricity swaps.

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

Share Capital

As at February 28, 2022, Paramount had 139.5 million Common Shares outstanding (net of 1.5 million Common Shares held in trust under the Company's restricted share unit plan) and 10.8 million options to acquire Common Shares outstanding, of which 2.4 million options are exercisable.

For the year ended December 31, 2021, Paramount issued 5.2 million Common Shares on conversion of the Convertible Debentures and 1.5 million Common Shares on the exercise of Paramount Options.

Dividends and NCIB

In July 2021, Paramount began paying monthly dividends with respect to its Common Shares. Dividends declared in the year ended December 31, 2021 totaled $0.20 per Common Share.

The Company paid a dividend of $0.06 per Common Share on January 31, 2022 to the shareholders of record on January 15, 2022 and a dividend of $0.06 per Common Share on February 28, 2022 to shareholders of record on February 15, 2022. The Company announced an increase to the regular monthly dividend to $0.08 per Common Share beginning in March 2022.

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

FOURTH QUARTER RESULTS

Netback [1]

Three months ended December 31	2021		2020	
		($/Boe) [2][3]		*($/Boe)* [2][3]
Natural gas revenue	**124.7**	***4.76***	66.7	*2.83*
Condensate and oil revenue	**281.1**	***94.46***	123.3	*52.03*
Other NGLs revenue	**27.4**	***54.61***	9.5	*20.61*
Royalty and other revenue	**1.1**	***–***	2.5	*–*
Petroleum and natural gas sales	**434.3**	***55.37***	202.0	*29.89*
Royalties	**(52.5)**	***(6.69)***	(11.7)	*(1.73)*
Operating expense	**(91.0)**	***(11.61)***	(79.8)	*(11.80)*
Transportation and NGLs processing	**(26.1)**	***(3.33)***	(24.6)	*(3.63)*
Netback	**264.7**	***33.74***	85.9	*12.73*
Risk management contract settlements	**(72.4)**	***(9.23)***	7.9	*1.18*
Netback including risk management contract settlements [4]	**192.3**	***24.51***	93.8	*13.91*

(1) Netback is a non-GAAP financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure.
(2) Natural gas revenue shown per Mcf.
(3) When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure and Netback and Netback including risk management contract settlements are non-GAAP ratios. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures.
(4) Netback including risk management contract settlements is a non-GAAP financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure.

Fourth quarter 2021 petroleum and natural gas sales were $434.3 million, an increase of $232.3 million from the fourth quarter of 2020, mainly due to higher commodity prices and sales volumes.

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

	Natural gas	Condensate and oil	Other NGLs	Royalty and other	Total
Three months ended December 31, 2020	66.7	123.3	9.5	2.5	202.0
Effect of changes in realized prices	50.6	126.3	17.0	–	193.9
Effect of changes in sales volumes	7.4	31.5	0.9	–	39.8
Change in royalty and other revenue	–	–	–	(1.4)	(1.4)
Three months ended December 31, 2021	**124.7**	**281.1**	**27.4**	**1.1**	**434.3**

Sales Volumes [1]

	Three months ended December 31											
	Natural gas *(MMcf/d)*			Condensate and oil *(Bbl/d)*			Other NGLs *(Bbl/d)*			Total *(Boe/d)*		
	2021	2020	*% Change*	**2021**	2020	*% Change*	**2021**	2020	*% Change*	**2021**	2020	*% Change*
Grande Prairie	**158.9**	94.3	*69*	**26,278**	19,635	*34*	**3,276**	2,429	*35*	**56,035**	37,782	*48*
Kaybob	**92.4**	118.2	*(22)*	**4,539**	5,410	*(16)*	**1,788**	1,953	*(8)*	**21,725**	27,056	*(20)*
Central Alberta and Other	**33.5**	43.8	*(24)*	**1,525**	707	*116*	**398**	605	*(34)*	**7,505**	8,622	*(13)*
Total	**284.8**	256.3	*11*	**32,342**	25,752	*26*	**5,462**	4,987	*10*	**85,265**	73,460	*16*

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

Sales volumes in the fourth quarter of 2021 averaged 85,265 Boe/d compared to 73,460 Boe/d in the fourth quarter of 2020. The Company focused its capital program in 2020 and 2021 on its developments at Karr and Wapiti, which resulted in higher 2021 sales volumes in the liquids rich Grande Prairie Region and lower sales volumes in the Kaybob Region due to declines.

At Karr, fourth quarter 2021 sales volumes were 41,629 Boe/d (50% liquids) compared to 26,914 Boe/d (56% liquids) in the same period in 2020. The increase mainly resulted from development activities where Paramount brought 19 new wells on production in 2021.

Sales volumes at Wapiti increased to 14,350 Boe/d (60% liquids) in the fourth quarter of 2021 compared to 10,764 Boe/d (64% liquids) in 2020. The increase mainly resulted from development activities where the Company brought 10 wells on production in 2021 in addition to five new wells brought onstream in the fourth quarter of 2020.

Fourth quarter 2021 sales volumes were lower by approximately 2,700 Boe/d (15.4 MMcf/d of conventional natural gas and 142 Bbl/d of NGLs) in the Kaybob Region and approximately 2,700 Boe/d (12.3 MMcf/d of shale gas and 693 Bbl/d of NGLs) in the Central Alberta and Other Region compared to the fourth quarter of 2020 due to non-core dispositions completed in 2021.

Commodity Prices (1)

Three months ended December 31	2021	2020	% Change
Natural Gas			
Paramount realized price ($/Mcf)	**4.76**	2.83	*68*
AECO daily spot ($/GJ)	**4.41**	2.50	*76*
AECO monthly index ($/GJ)	**4.68**	2.62	*79*
Dawn ($/MMBtu)	**5.86**	2.97	*97*
NYMEX (US$/MMBtu)	**4.85**	2.76	*76*
Malin – monthly index (US$/MMBtu)	**5.99**	2.93	104
Condensate and Oil			
Paramount realized condensate & oil price ($/Bbl)	**94.46**	52.03	*82*
Edmonton light sweet crude oil ($/Bbl)	**92.14**	49.17	*87*
West Texas Intermediate crude oil (US$/Bbl)	**77.19**	42.66	81
Other NGLs			
Paramount realized Other NGLs price ($/Bbl)	**54.61**	20.61	*165*
Conway – propane ($/Bbl)	**65.95**	30.32	*118*
Belvieu – butane ($/Bbl)	**78.18**	36.10	*117*
Foreign Exchange			
$CDN / 1 $US	**1.26**	1.30	*(3)*

(1) Realized prices per Mcf and Bbl are supplementary financial measures. Refer to the "Specified Financial Measures" section of this MD&A for more information.

Realized natural gas prices in the fourth quarter of 2021 included the impact of approximately 117,000 GJ/d of natural gas sales under fixed-price physical contracts at C$3.16/GJ (fourth quarter of 2020 – approximately 67,000 GJ/d of natural gas at C$2.18/GJ).

The Company's propane and butane contracts in place in the fourth quarter of 2021 had more favorable differentials to West Texas Intermediate reference prices than the same period in 2020.

Royalties were $52.5 million in the fourth quarter of 2021, $40.8 million higher than the same period in 2020, primarily as a result of higher commodity prices and increased sales volumes. Royalty rates were higher at Karr as a greater proportion of wells have fully utilized new well royalty incentives.

Operating expenses were $91.0 million in the fourth quarter of 2021 compared to $79.8 million in the same period in 2020. Operating costs increased in the fourth quarter of 2021 mainly due to higher production and processing fees in the Grande Prairie Region in 2021 and higher electricity prices in the Kaybob Region in

2021. These increases were partially offset by decreases due to lower production in the Kaybob and Central Alberta and Other Regions.

Operating expense was $11.61 per Boe in the fourth quarter of 2021 compared to $11.80 per Boe in the same period in 2020, mainly due to the impact of higher production and the changes in costs described above. Fourth quarter 2021 operating costs at Karr were $9.38 per Boe compared to $11.24 per Boe in the fourth quarter of 2020.

Transportation and NGLs processing costs in the fourth quarter of 2021 were higher than the same period in 2020, mainly due to higher production volumes at Karr and Wapiti.

Net Income

Three months ended December 31	2021	2020
Petroleum and natural gas sales	434.3	202.0
Royalties	(52.5)	(11.7)
Revenue	381.8	190.3
Gain (loss) on risk management contracts	14.1	(24.1)
	395.9	166.2
Expenses		
Operating expense	91.0	79.8
Transportation and NGLs processing	26.1	24.6
General and administrative	11.9	9.1
Share-based compensation	7.7	6.8
Depletion, depreciation and net impairment reversals	100.4	(239.1)
Exploration and evaluation	9.2	8.8
(Gain) loss on sale of oil and gas assets	–	(0.1)
Interest and financing	9.0	17.8
Accretion of asset retirement obligations	10.5	11.2
Other	(7.5)	0.2
	258.3	(80.9)
Income before tax	137.6	247.1
Income tax expense (recovery)		
Deferred	36.6	(64.4)
Net income	101.0	311.5

Paramount recorded net income of $101.0 million for the three months ended December 31, 2021 compared to $311.5 million in the same period in 2020. Significant factors contributing to the change are shown below:

Three months ended December 31	
Net income – 2020	**311.5**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	178.8
• Gain on risk management contracts in 2021 compared to a loss in 2020	38.2
• Lower interest and financing expense in 2021	8.8
• Settlements in 2021	7.0
• Higher depletion, depreciation and impairment reversals in 2021, mainly due to impairment reversals of $333.7 million in the fourth quarter of 2020	(339.5)
• Income tax expense in 2021 compared to a recovery in 2020	(101.0)
• Other	(2.8)
Net income – 2021	**101.0**

Cash From Operating Activities

Cash from operating activities for the three months ended December 31, 2021 was $191.8 million compared to $53.2 million for the same period in 2020. Significant factors contributing to the change are shown below:

Three months ended December 31	
Cash from operating activities – 2020	**53.2**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	178.8
• Change in non-cash working capital	32.6
• Lower interest and financing expense in 2021	11.0
• Payments on risk management contract settlements in 2021 compared to receipts in 2020	(80.4)
• Other	(3.4)
Cash from operating activities – 2021	**191.8**

Adjusted Funds Flow [(1)]

The following is a reconciliation of adjusted funds flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements:

Three months ended December 31	2021	2020
Cash from operating activities	**191.8**	53.2
Change in non-cash working capital	**(20.1)**	12.5
Geological and geophysical expense	**2.9**	2.1
Asset retirement obligations settled	**7.0**	0.1
Closure costs	**–**	–
Provisions	**–**	–
Settlements	**(7.0)**	–
Transaction and reorganization costs	**–**	–
Adjusted funds flow	**174.6**	67.9
Adjusted funds flow ($/Boe)	**22.25**	10.05

(1) Adjusted funds flow is a capital management measure used by Paramount. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure.
(2) Adjusted funds flow ($/Boe) is a supplementary financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information.

Adjusted funds flow in the fourth quarter of 2021 was $174.6 million compared to $67.9 million in the same period in 2020. Significant factors contributing to the change are shown below:

Three months ended December 31	
Adjusted funds flow – 2020	**67.9**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	178.8
• Lower interest and financing expense in 2021	11.0
• Payments on risk management contract settlements in 2021 compared to receipts in 2020	(80.4)
• Other	(2.7)
Adjusted funds flow – 2021	**174.6**

Free Cash Flow [1]

The following is a reconciliation of free cash flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements:

Three months ended December 31	2021	2020
Cash from operating activities	**191.8**	53.2
Change in non-cash working capital	**(20.1)**	12.5
Geological and geophysical expense	**2.9**	2.1
Asset retirement obligations settled	**7.0**	0.1
Closure costs	**–**	–
Provisions	**–**	–
Settlements	**(7.0)**	–
Transaction and reorganization costs	**–**	–
Adjusted funds flow	**174.6**	67.9
Capital expenditures	**(65.7)**	(65.1)
Geological and geophysical expense	**(2.9)**	(2.1)
Asset retirement obligation settled	**(7.0)**	(0.1)
Free cash flow	**99.0**	0.6

(1) Free cash flow is a capital management measure used by Paramount. Refer to the "Specified Financial Measures" section of this MD&A for more information on this measure. Prior period results have been updated to reflect the current period presentation.

Free cash flow in the fourth quarter of 2021 was $99.0 million compared to $0.6 million in the same period in 2020. Significant factors contributing to the change are shown below:

Three months ended December 31	
Free cash flow – 2020	**0.6**
• Change in adjusted funds flow (as described in the "Adjusted Funds Flow" section above)	106.7
• Higher asset retirement obligations settled in 2021	(6.9)
• Higher geological and geophysical expense in 2021	(0.8)
• Higher capital expenditures in 2021	(0.6)
Free cash flow – 2021	**99.0**

Capital Expenditures by Region

Three months ended December 31	2021	2020
Grande Prairie Region	**57.7**	64.3
Kaybob Region	**3.8**	1.8
Central Alberta and Other Region	**2.6**	0.8
Corporate	**1.6**	(1.8)
Capital expenditures	**65.7**	65.1

Capital expenditures in the fourth quarter of 2021 totaled $65.7 million, with the majority of spending directed towards drilling and completion programs in the Grande Prairie Region.

QUARTERLY INFORMATION [1]

	2021				2020			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**434.3**	369.1	299.7	279.9	202.0	138.8	113.2	172.1
Net income (loss)	**101.0**	292.7	(74.3)	(82.5)	311.5	(23.3)	(75.7)	(235.1)
Per share – basic ($/share)	***0.75***	*2.20*	*(0.56)*	*(0.62)*	*2.35*	*(0.17)*	*(0.57)*	*(1.76)*
Per share – diluted ($/share)	***0.70***	*2.06*	*(0.56)*	*(0.62)*	*2.35*	*(0.17)*	*(0.57)*	*(1.76)*
Cash from (used in) operating activities	**191.8**	97.0	112.1	81.3	53.2	11.4	(14.2)	30.5
Per share – basic ($/share)	***1.42***	*0.73*	*0.84*	*0.61*	*0.40*	*0.09*	*(0.11)*	*0.23*
Per share – diluted ($/share)	***1.33***	*0.68*	*0.84*	*0.61*	*0.40*	*0.09*	*(0.11)*	*0.23*
Adjusted funds flow	**174.6**	146.4	86.0	90.9	67.9	29.5	19.0	33.5
Per share – basic ($/share)	***1.29***	*1.12*	*0.65*	*0.69*	*0.51*	*0.22*	*0.14*	*0.25*
Per share – diluted ($/share)	***1.21***	*1.04*	*0.65*	*0.69*	*0.51*	*0.22*	*0.14*	*0.25*
Dividends declared ($/share)	**0.14**	0.06	–	–	–	–	–	–
Sales volumes								
Natural gas (MMcf/d)	**284.8**	269.7	273.1	273.1	256.3	224.0	253.2	261.5
Condensate and oil (Bbl/d)	**32,342**	32,177	29,543	29,854	25,752	19,782	22,823	21,898
Other NGLs (Bbl/d)	**5,462**	5,017	4,938	5,170	4,987	3,952	3,817	4,539
Total (Boe/d)	**85,265**	82,150	79,995	80,540	73,460	61,064	68,839	70,022
Liquids %	***44%***	*45%*	*43%*	*43%*	*42%*	*39%*	*39%*	*38%*
Realized prices								
Natural gas ($/Mcf)	**4.76**	3.89	3.01	3.14	2.83	1.94	1.94	2.25
Condensate and oil ($/Bbl)	**94.46**	84.42	77.96	69.20	52.03	48.74	29.05	55.92
Other NGLs ($/Bbl)	**54.61**	47.05	32.11	32.29	20.61	18.10	12.28	10.75
Total ($/Boe)	**55.37**	48.84	41.17	38.61	29.89	24.70	18.07	27.01

(1) Adjusted funds flow is a capital management measure used by Paramount. Each measure presented on a per share, $/Bbl, $/Mcf or $/Boe basis, other than net income (loss) per share, is a supplementary financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures.

Significant Items Impacting Quarterly Results

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

- Fourth quarter 2021 earnings include a charge of $19.9 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value and a loss of $14.1 million loss on risk management contracts.
- Third quarter 2021 earnings include aggregate impairment reversals of $282.6 million from previously recorded impairment charges of petroleum and natural gas assets and a $32.3 million gain on the sale of oil and gas assets, partially offset by a $47.0 million loss on risk management contracts.
- The second quarter 2021 loss includes a $75.7 million loss on risk management contracts and a charge of $42.0 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The first quarter 2021 loss includes an $81.2 million loss on risk management contracts, a charge of $69.5 million mainly related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value and a $41.4 million gain on the sale of oil and gas assets.

- Fourth quarter 2020 earnings include aggregate impairment reversals of $333.7 million from previously recorded impairment charges of petroleum and natural gas assets and a deferred income tax recovery of $64.4 million, partially offset by a charge of $29.7 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The third quarter 2020 loss includes a recovery of $25.6 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The second quarter 2020 loss includes a recovery of $13.6 million related to deferred income tax.
- The first quarter 2020 loss includes a $191.8 million impairment of petroleum and natural gas assets, and a derecognition of $130.0 million of the deferred income tax asset, partially offset by a recovery of $94.8 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value ascribed to property, plant and equipment.

OTHER INFORMATION

Contractual Obligations

Paramount had the following contractual obligations at December 31, 2021: (1)

	Within 1 year	After one year but not more than three years	After three years but not more than five years	More than five years	Total
Paramount Facility	–	389.1	–	–	**389.1**
Transportation and processing commitments (2)	236.1	465.7	423.3	999.0	**2,124.1**
Asset retirement obligations (3)	20.4	83.5	87.1	1,127.7	**1,318.7**
Finance lease and other commitments (4)	26.2	22.3	6.9	26.7	**82.1**
	282.7	**960.6**	**517.3**	**2,153.4**	**3,914.0**

(1) Excludes risk management liabilities and accounts payable and accrued liabilities, which are described in Note 14 in the Consolidated Financial Statements.
(2) Certain of the transportation and processing commitments are secured by outstanding letters of credit totaling $13.0 million at December 31, 2021 (December 31, 2020 - $13.2 million).
(3) Undiscounted, uninflated asset retirement obligations estimated as at December 31, 2021. Does not include impact of government funding. Estimated costs and timing of settlement are revised from time-to-time based on new information.
(4) Includes future commitments of $34 million relating to a new long-term lease expected to commence in June 2022.

Transportation and processing commitments mainly relate to long-term firm service arrangements for the processing and transportation of the Company's sales volumes.

Contingencies

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

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

Provisions

For the year ended December 31, 2021, the Company recorded provisions of $24.0 million with respect to arrangements with a service provider. The Company has unsettled claims of a greater amount against the same service provider with respect to certain related matters, which have not been recognized. The outcome of all of these matters remains uncertain.

In the first quarter of 2020, a provision of $4.7 million was recorded related to a pending partner dispute.

Settlements

In the fourth quarter of 2021, Paramount recognized $7.0 million, net of legal fees, in connection with the settlement of outstanding litigation relating to damages to a well.

NEW AND UPDATED ACCOUNTING POLICIES AND STANDARDS

Adoption of Accounting Standards

Effective January 1, 2021, the Company adopted the phase two amendments to IFRS 9 – *Financial Instruments,* IAS 39 – *Financial Instruments: Recognition and Measurement*, IFRS 7 – *Financial Instruments: Disclosures,* IFRS 4 – *Insurance Contracts and* IFRS 16 – *Leases*. These amendments provide guidance in applying IFRS when there are changes to contractual cash flows or hedging relationships arising from the replacement of an interest rate benchmark with an alternative benchmark rate pursuant to the Interbank Offered Rate ("IBOR") reform. There has been no impact on the recognized assets, liabilities or comprehensive income (loss) of the Company resulting from the adoption of these amendments. The Company's floating-to-fixed interest rate swaps, which are described in Note 14 in the Consolidated Financial Statements, may be impacted by these amendments in the future as hedge accounting is applied to these instruments and hedging relationships may be impacted by the IBOR reform.

Future Changes in Accounting Standards

The IASB has announced amendments to accounting standards and interpretations and new accounting standards that are effective for annual periods beginning on or after January 1, 2022. These standards and interpretations have not been applied to the Consolidated Financial Statements for the year ended December 31, 2021. Paramount does not expect that these changes will have a material impact on the Company's Consolidated Financial Statements on adoption.

DISCLOSURE CONTROLS AND PROCEDURES

As of the year ended December 31, 2021, an evaluation of the effectiveness of Paramount's disclosure controls and procedures ("DCP"), as defined under National Instrument 52-109 "*Certification of Disclosure in Issuers' Annual and Interim Filings*" ("NI 52-109"), was performed by the Company's Management with the oversight of the Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's DCP are effective as of December 31, 2021.

It should be noted that while the Company's DCP are intended to provide a reasonable level of assurance that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified in securities legislation, disclosure controls and procedures cannot be expected to prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, with the oversight of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting ("ICFR") as defined under NI 52-109 as at December 31, 2021. In making its evaluation, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013). Based on this evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's ICFR was effective as of December 31, 2021.

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

Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2021, there was no change in the Company's ICFR that materially affected, or is reasonably likely to materially affect, the Company's ICFR.

RISK FACTORS

Readers should, in conjunction with their review of this MD&A, carefully review the "Risk Factors" section in the Company's Annual Information Form for the year ended December 31, 2021, which is available under the Company's profile on SEDAR at www.sedar.com.

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

CRITICAL ACCOUNTING ESTIMATES

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

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

A description of the accounting judgments, estimates and assumptions that are considered significant is set out below.

Exploration or Development

The Company is required to apply judgment when designating a project as exploration and evaluation ("E&E") or development, including assessments of geological and technical characteristics and other factors related to each project.

Exploration and Evaluation Projects

The accounting for E&E projects requires Management to make judgments as to whether exploratory projects have discovered economically recoverable quantities of petroleum and natural gas, which requires the quantity and realizable value of such petroleum and natural gas to be estimated. Previous estimates are sometimes revised as new information becomes available. Where it is determined that an exploratory project did not discover economically recoverable petroleum and natural gas, the costs are written-off as E&E expense.

If hydrocarbons are encountered, but further appraisal activity is required, the exploratory costs remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the petroleum and natural gas is economically viable. The concept of "sufficient progress" is a judgmental area, and it is possible to have exploratory costs remain capitalized for several years while additional exploratory activities are carried out or the Company seeks government, regulatory or partner approval for development plans. E&E assets are subject to ongoing technical, commercial and Management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. Factors considered by Management in making this assessment may include: changes to project economics, expected quantities of petroleum and natural gas, expected production techniques, drilling results, estimated capital expenditures and production costs, results of other operators in the region and access to infrastructure and potential infrastructure expansions. Where it is determined that an exploratory project is not economically viable, the costs are written-off as E&E expense.

Reserves Estimates

Reserves engineering is an inherently complex and subjective process of estimating underground accumulations of petroleum and natural gas. The process relies on judgments based on the interpretation of available geological, geophysical, engineering and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of such data, the accuracy of various economic assumptions and the judgment of those preparing the estimate. Because these estimates depend on many assumptions, all of which may differ from actual results, reserves estimates, and estimates of future net revenue will be different from the sales volumes ultimately recovered and net revenues actually realized. Changes in market conditions, regulatory matters, the results of subsequent drilling, testing and production and other factors may result in revisions to the original estimates.

Estimates of reserves impact the assessment of whether a new well has found economically recoverable reserves, depletion rates, the estimated fair value of petroleum and natural gas properties acquired in a business combination and the estimated recoverable amount of petroleum and natural gas properties used for the purposes of impairment and impairment reversal assessments, all of which could have a material impact on earnings.

Business Combinations

Management is required to exercise judgment in determining whether assets acquired and liabilities assumed constitute a business. A business consists of an integrated set of assets and activities, comprised of inputs and processes, that is capable of being conducted and managed as a business by a market participant.

Business combinations are accounted for using the acquisition method of accounting, whereby the net identifiable assets acquired are recorded at fair value. The fair value of individual assets is often required to be estimated, which may involve estimating the fair values of proved plus probable reserves, contingent resources, tangible assets, undeveloped land, intangible assets and other assets. These estimates incorporate assumptions using indicators of fair value, as determined by Management. Changes in any of the estimates or assumptions used in determining the fair value of the net identifiable assets acquired may impact the carrying values assigned to assets acquired and liabilities assumed and could have a material impact on earnings.

Estimates of Recoverable Amounts

Estimates of recoverable amounts used in impairment and impairment reversal assessments often incorporate level three fair value hierarchy inputs, including estimated volumes and future net revenues from proved plus probable reserves, contingent resource estimates, future net cash flow estimates related to other long-lived assets and internal and external market metrics used to estimate fair value based on comparable assets and transactions. By their nature, such estimates are subject to measurement uncertainty. Changes in such estimates, and differences between actual and estimated amounts, could have a material impact on earnings.

Determination of CGUs

The recoverability of the carrying value of petroleum and natural gas assets is generally assessed at the CGU level. The determination of the properties and other assets grouped within a particular CGU is based on Management's judgment with respect to the integration between assets, shared infrastructure and cash flows, the overall significance of individual properties and the manner in which Management monitors its operations and allocates capital. Changes in the assets comprising CGUs could have an impact on estimated recoverable amounts used in impairment assessments and could have a material impact on earnings.

Depletion

Depletion rates are determined based on Management's estimates of the expected usage pattern of the Company's petroleum and natural gas assets, including assumptions regarding future production volumes, future development capital and the useful lives of production equipment and gathering systems.

Investments in Securities

The Company's investments in securities are accounted for as fair value through OCI financial assets. Management is required to exercise judgment in estimating the fair value of investments in the securities of corporations that are not publicly traded using available market inputs and other assumptions. Changes in estimates of fair value for such investments could have a material impact on comprehensive income.

Provisions

A provision is recognized where the Company has determined that it has a present obligation arising from past events and the settlement of the obligation is expected to result in an outflow of economic benefits.

The determination of whether the Company has a present obligation arising from past events requires Management to exercise judgement as to the facts and circumstances of the event and the extent of any expected obligations of Paramount. Changes in facts and circumstances as a result of new information and other developments may impact Management's assessment of the Company's obligations, if any, in respect of such events. Changes in such estimates could have a material impact on Paramount's assets, liabilities, revenues, expenses and earnings.

Asset Retirement Obligations

Estimates of asset retirement costs are based on assumptions regarding the methods, timing, economic environment and regulatory standards that are expected to exist at the time assets are retired. Management also exercises judgment to determine the credit-adjusted risk-free discount rate at the end of each reporting period which may change in response to numerous market factors. The Company adjusts estimated amounts periodically as assumptions are updated to incorporate new information. The actual amount and timing of payments to settle the obligations may differ materially from estimates.

Share-Based Payments

The Company estimates the grant date fair value of stock options awarded using the Black-Scholes model. The inputs used to determine the estimated value of the options are based on assumptions regarding share price volatility, the life of the options, forfeiture rates, the risk-free interest rate and the dividend yield on the Common Shares. By their nature, these inputs are subject to measurement uncertainty and require Management to exercise judgment.

Income Taxes

Accounting for income taxes is a complex process requiring Management to interpret frequently changing laws and regulations and make judgments and estimates related to the application of tax law, the timing of temporary difference reversals and the likelihood of realizing deferred income tax assets. All tax filings are subject to subsequent government audits and potential reassessment. These interpretations and judgments, and changes related to them, impact current and deferred income tax provisions, the carrying value of deferred income tax assets and liabilities and could have a material impact on earnings.

PRODUCT TYPE INFORMATION

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

	2021				2020				Annual		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	2021	2020	2019
SALES VOLUMES – BY PRODUCT TYPE											
Shale gas (MMcf/d)	220.4	207.1	205.8	197.8	170.7	141.0	156.0	158.9	207.9	156.7	166.0
Conventional natural gas (MMcf/d)	64.4	62.6	67.3	75.3	85.6	83.0	97.2	102.6	67.3	92.0	137.3
Natural gas (MMcf/d)	284.8	269.7	273.1	273.1	256.3	224.0	253.2	261.5	275.2	248.7	303.3
Condensate (Bbl/d)	29,797	29,670	26,784	27,017	22,782	17,020	19,615	17,908	28,328	19,334	19,746
Other NGLs (Bbl/d)	5,462	5,017	4,938	5,170	4,987	3,952	3,817	4,539	5,147	4,325	6,767
NGLs (Bbl/d)	35,259	34,687	31,722	32,187	27,769	20,972	23,432	22,447	33,475	23,659	26,513
Tight oil (Bbl/d)	497	475	494	479	437	457	381	575	487	462	631
Light and medium crude oil (Bbl/d)	2,048	2,032	2,265	2,358	2,533	2,305	2,827	3,416	2,174	2,768	4,703
Crude oil (Bbl/d)	2,545	2,507	2,759	2,837	2,970	2,762	3,208	3,991	2,661	3,230	5,334
Total (Boe/d)	85,265	82,150	79,995	80,540	73,460	61,064	68,839	70,022	82,001	68,340	82,394

SALES VOLUMES – BY REGION BY PRODUCT TYPE											
GRANDE PRAIRIE REGION											
Shale gas (MMcf/d)	156.5	145.8	132.2	120.6	92.7	66.0	76.8	73.1	138.8	77.2	78.0
Conventional natural gas (MMcf/d)	2.4	2.2	2.1	2.0	1.6	1.3	1.5	1.5	2.2	1.4	1.5
Natural gas (MMcf/d)	158.9	148.0	134.3	122.6	94.3	67.3	78.3	74.6	141.0	78.6	79.5
Condensate (Bbl/d)	26,272	26,639	24,086	23,974	19,635	13,959	16,292	14,058	25,253	15,991	13,920
Other NGLs (Bbl/d)	3,276	3,274	2,874	2,984	2,429	2,060	1,680	1,680	3,103	1,964	1,814
NGLs (Bbl/d)	29,548	29,913	26,960	26,958	22,064	16,019	17,972	15,738	28,356	17,955	15,734
Tight oil (Bbl/d)	–	–	–	–	–	–	–	–	–	–	–
Light and medium crude oil (Bbl/d)	6	9	4	–	–	1	17	39	5	14	53
Crude oil (Bbl/d)	6	9	4	–	–	1	17	39	5	14	53
Total (Boe/d)	56,035	54,586	49,345	47,385	37,782	27,237	31,039	28,214	51,869	31,076	29,040

KAYBOB REGION											
Shale gas (MMcf/d)	35.6	36.9	39.3	42.1	41.9	40.4	44.4	48.6	38.6	43.8	50.3
Conventional natural gas (MMcf/d)	56.8	54.4	58.0	65.8	76.3	73.4	87.1	91.6	58.6	82.1	95.9
Natural gas (MMcf/d)	92.4	91.3	97.3	107.9	118.2	113.8	131.5	140.2	97.2	125.9	146.2
Condensate (Bbl/d)	2,184	2,072	2,319	2,611	2,631	2,577	2,954	3,385	2,295	2,885	4,361
Other NGLs (Bbl/d)	1,788	1,415	1,569	1,677	1,953	1,363	1,718	2,218	1,612	1,812	2,476
NGLs (Bbl/d)	3,972	3,487	3,888	4,288	4,584	3,940	4,672	5,603	3,907	4,697	6,837
Tight oil (Bbl/d)	355	368	354	342	299	308	203	394	355	301	360
Light and medium crude oil (Bbl/d)	2,000	1,979	2,224	2,321	2,480	2,257	2,762	3,343	2,129	2,709	3,929
Crude oil (Bbl/d)	2,355	2,347	2,578	2,663	2,779	2,565	2,965	3,737	2,484	3,010	4,289
Total (Boe/d)	21,725	21,054	22,688	24,938	27,056	25,477	29,561	32,700	22,588	28,685	35,500

	2021				2020				Annual		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	2021	2020	2019
CENTRAL ALBERTA AND OTHER REGION											
Shale gas (MMcf/d)	28.2	24.4	34.3	35.1	36.1	34.6	34.8	37.1	30.5	35.7	37.7
Conventional natural gas (MMcf/d)	5.3	6.0	7.2	7.5	7.7	8.3	8.6	9.6	6.5	8.5	39.9
Natural gas (MMcf/d)	33.5	30.4	41.5	42.6	43.8	42.9	43.4	46.7	37.0	44.2	77.6
Condensate (Bbl/d)	1,341	959	379	433	515	484	369	465	781	458	1,464
Other NGLs (Bbl/d)	398	328	495	509	605	529	419	641	432	549	2,477
NGLs (Bbl/d)	1,739	1,287	874	942	1,120	1,013	788	1,106	1,213	1,007	3,941
Tight oil (Bbl/d)	142	107	140	136	138	149	178	180	131	161	271
Light and medium crude oil (Bbl/d)	42	44	37	37	54	47	48	33	40	46	721
Crude oil (Bbl/d)	184	151	177	173	192	196	226	213	171	207	992
Total (Boe/d)	7,505	6,510	7,962	8,217	8,622	8,350	8,239	9,108	7,544	8,579	17,854

	2021				2020				Annual		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	2021	2020	2019
SALES VOLUMES – KARR BY PRODUCT TYPE											
Shale gas (MMcf/d)	122.5	113.0	106.3	89.1	69.6	48.6	45.5	58.7	107.9	55.6	67.2
Conventional natural gas (MMcf/d)	1.5	1.4	1.3	1.1	0.9	0.6	0.6	0.7	1.3	0.7	0.5
Natural gas (MMcf/d)	124.0	114.4	107.6	90.2	70.5	49.2	46.1	59.4	109.2	56.3	67.7
Condensate (Bbl/d)	18,521	18,328	18,458	16,095	13,348	9,541	7,501	9,691	17,858	10,028	10,024
Other NGLs (Bbl/d)	2,449	2,477	2,281	2,108	1,817	1,503	829	1,290	2,330	1,361	1,453
NGLs (Bbl/d)	20,970	20,805	20,739	18,203	15,165	11,044	8,330	10,981	20,188	11,389	11,477
Total (Boe/d)	41,629	39,878	38,679	33,230	26,914	19,246	16,009	20,885	38,381	20,777	22,755

SALES VOLUMES – WAPITI BY PRODUCT TYPE											
Shale gas (MMcf/d)	34.1	32.7	25.9	31.5	22.8	17.4	31.3	14.5	31.0	21.5	10.8
Conventional natural gas (MMcf/d)	0.6	0.6	0.5	0.6	0.5	0.4	0.6	0.3	0.6	0.4	0.3
Natural gas (MMcf/d)	34.7	33.3	26.4	32.1	23.3	17.8	31.9	14.8	31.6	21.9	11.1
Condensate (Bbl/d)	7,749	8,310	5,629	7,884	6,286	4,414	8,786	4,364	7,395	5,959	3,879
Other NGLs (Bbl/d)	819	790	582	867	589	548	841	386	764	591	344
NGLs (Bbl/d)	8,568	9,100	6,211	8,751	6,875	4,962	9,627	4,750	8,159	6,550	4,223
Total (Boe/d)	14,350	14,651	10,604	14,107	10,764	7,925	14,940	7,209	13,432	10,207	6,082

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 increase 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) less royalties, operating expense and transportation and NGLs processing expense. 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.

The following table shows the calculation of netback and netback including risk management contract settlements for the years ended December 31, 2021 and 2020 and for the three months ended December 31, 2021 and 2020:

	Year ended December 31		Three months ended December 31	
	2021	**2020**	**2021**	**2020**
Natural gas revenue (1)	**373.3**	204.9	**124.7**	66.7
Condensate and oil revenue (1)	**926.5**	383.8	**281.1**	123.3
Other NGLs revenue (1)	**78.6**	24.7	**27.4**	9.5
Royalty and other revenue (1)	**4.6**	12.6	**1.1**	2.5
Petroleum and natural gas sales (2)	**1,383.0**	626.0	**434.3**	202.0
Royalties (2)	**(127.0)**	(31.3)	**(52.5)**	(11.7)
Operating expense (2)	**(340.4)**	(297.1)	**(91.0)**	(79.8)
Transportation and NGLs processing (2)	**(114.5)**	(101.3)	**(26.1)**	(24.6)
Netback	**801.1**	196.3	**264.7**	85.9
Risk management contract settlements (3)	**(218.3)**	37.6	**(72.4)**	7.9
Netback including risk management contract settlements	**582.8**	233.9	**192.3**	93.8

(1) Refer to Note 15 in the Consolidated Financial Statements for the year-ended December 31, 2021 and December 31, 2020 amounts.
(2) Refer to the "Consolidated Statements of Comprehensive Income (Loss)" in the Consolidated Financial Statements for the year-ended December 31, 2021 and December 31, 2020 amounts.
(3) Refer to Note 14 in the Consolidated Financial Statements for the year-ended December 31, 2021 and December 31, 2020 amounts.

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, net debt and net debt to adjusted funds flow 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 18 – Capital Structure in the Consolidated Financial Statements for a description of the composition and use of these measures. Refer also to "Liquidity and Capital Resources" in this MD&A.

A reconciliation of adjusted funds flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements, for: (i) the years ended December 31, 2021, 2020 and 2019 is provided in this MD&A under "Consolidated Results – Adjusted Funds Flow" and (ii) the three months ended December 31, 2021 and 2020 is provided in this MD&A under "Fourth Quarter Results – Adjusted Funds Flow".

A reconciliation of free cash flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements, for: (i) the years ended December 31, 2021, 2020 and 2019 is provided in this MD&A under "Consolidated Results – Free Cash Flow" and (ii) the three months ended December 31, 2021 and 2020 is provided in this MD&A under "Fourth Quarter Results – Free Cash Flow". Prior period results have been reclassified to conform with the current years' presentation.

A calculation of net debt as at December 31, 2021 and 2020 is provided in this MD&A under "Liquidity and Capital Resources". At December 31, 2021 Paramount's net debt to adjusted funds flow was 0.9 times (December 31, 2020 – 5.7 times).

Supplementary Financial Measures

This MD&A 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, (ii) realized prices, petroleum and natural gas sales, adjusted funds flow, revenue, royalties, operating expenses and transportation and NGLs processing expenses on a $/Bbl, $/Mcf or $/Boe basis and (iii) royalty rate.

Cash from operating activities, adjusted funds flow and free cash flow on a per share – basic basis are calculated by dividing the 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 the 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.

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

Royalty rate is calculated by dividing royalties by petroleum and natural gas sales less royalty and other revenue.

ADVISORIES

Forward-looking Information

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

- planned capital expenditures in 2022;
- forecast sales volumes for 2022 and certain periods therein;
- the expectation that well outperformance in 2022 will offset the impact of the unplanned outage at the third-party operated Wapiti natural gas processing facility;
- forecast free cash flow in 2022;
- the Company's priorities and expectations respecting the allocation of free cash flow;
- the expectation that the Company will achieve its net debt target of about $300 million in the third quarter of 2022 and the implied net debt to adjusted funds flow ratio at the end of the third quarter of 2022;
- planned abandonment and reclamation expenditures and activities in 2022;
- preliminary anticipated capital expenditures in 2023 and the resulting expected 2023 average sales volumes and free cash flow;
- planned exploration, development and production activities, including the expected timing of drilling, completing and bringing new wells on production;
- the expectation that the Company will be able to fund budgeted capital expenditures and net abandonment and reclamation expenditures in 2022 with cash from operating activities;
- the anticipation that legal proceedings will not have a material impact on Paramount's financial position;
- the payment of future dividends under the Company's monthly dividend program; and
- the potential impacts of the COVID-19 pandemic.

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

- future commodity prices;
- 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 production successfully to current and new customers;

- the ability of Paramount and its industry partners to obtain drilling success (including in respect of anticipated production volumes, reserves additions, product yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals;
- the receipt of benefits under government programs;
- the application of regulatory requirements respecting abandonment and reclamation;
- the merits of outstanding and pending legal proceedings; 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 MD&A, undue reliance should not be placed on the forward-looking information as Paramount can give no assurance that such expectations will prove to be correct. Forward-looking information is based on expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Paramount and described in the forward-looking information. The material risks and uncertainties include, but are not limited to:

- those risks set out in this MD&A under "Risk Factors";
- fluctuations in commodity prices;
- 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;
- 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, reserves additions, product yields (including condensate to natural gas ratios), resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate product processing, transportation, fractionation, and storage capacity on acceptable terms;
- operational risks in exploring for, developing, producing and transporting sales volumes, including the risk of spills, leaks or blowouts;
- the ability to obtain equipment, materials, services and personnel in a timely manner and at an acceptable cost;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities);
- processing, pipeline and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves estimates;
- general business, economic and market conditions;
- the ability to generate sufficient cash from operating activities and obtain financing to fund planned exploration, development and operational activities and meet current and future commitments and obligations (including product processing, transportation, fractionation and similar commitments and obligations);
- changes in, or in the interpretation of, laws, regulations or policies (including environmental laws);
- the ability to obtain required governmental or regulatory approvals in a timely manner, and to enter into and maintain leases and licenses;
- the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access;
- 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, regulatory actions, audits and assessments; and
- other risks and uncertainties described elsewhere in this document and in Paramount's other filings with Canadian securities authorities.

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

The foregoing list of risks is not exhaustive. For more information relating to risks, see the section titled "Risk Factors" in Paramount's annual information form for the year ended December 31, 2021, which is available on SEDAR at www.sedar.com. The forward-looking information contained in this document is made as of the date hereof and, except as required by applicable securities law, Paramount undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Certain forward-looking information in this MD&A, including forecast free cash flow in 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 MD&A. Such assumptions are based on management's assessment of the relevant information currently available and any financial outlook included in this MD&A is provided for the purpose of helping readers understand Paramount's current expectations and plans for the future. Readers are cautioned that reliance on any financial outlook may not be appropriate for other purposes or in other circumstances and that the risk factors described above or other factors may cause actual results to differ materially from any financial outlook.

Oil and Gas Measures and Definitions

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

Abbreviations

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

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

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

This MD&A contains disclosures expressed as "Boe", "$/Boe" and "Boe/d". Natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil when converting natural gas to Boe. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. For the year ended December 31, 2021, the value ratio between crude oil and natural gas was approximately 24:1. 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.

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.

Consolidated Financial Statements
As at December 31, 2021 and 2020 and for the years then ended

MANAGEMENT'S REPORT

The accompanying Consolidated Financial Statements of Paramount Resources Ltd. (the "Company") are the responsibility of Management and have been approved by the Company's Board of Directors. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments. If alternate accounting methods exist, Management has chosen those policies it considers the most appropriate in the circumstances. Financial information included in the Company's annual report, including Management's Discussion and Analysis, is consistent with these Consolidated Financial Statements.

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The Company's internal control system was designed to provide reasonable assurance that all transactions are recorded that are necessary for the preparation and presentation of financial statements in accordance with International Financial Reporting Standards, that such transactions are recorded accurately and that the Company's assets are safeguarded.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal control. The Board of Directors fulfills this responsibility through the Audit Committee, which is comprised entirely of non-Management directors. The Audit Committee meets regularly with Management and the independent auditors to ensure that Management's responsibilities are properly discharged and to review the Consolidated Financial Statements. The Audit Committee reports its findings to the Board of Directors for consideration when approving the annual Consolidated Financial Statements for issuance. The Audit Committee also considers, for review by the Board of Directors and approval by the shareholders, the engagement or re-appointment of the independent auditors.

Ernst & Young LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the Consolidated Financial Statements in accordance with Canadian Generally Accepted Auditing Standards. Ernst & Young LLP has full and free access to the Board of Directors, the Audit Committee and Management.

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

/s/ P.R. Kinvig
P.R. Kinvig
Chief Financial Officer

March 1, 2022

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Paramount Resources Ltd.

Opinion

We have audited the consolidated financial statements of Paramount Resources Ltd. and its subsidiaries (collectively, the Company), which comprise the consolidated balance sheets as at December 31, 2021 and 2020, and the consolidated statements of comprehensive income (loss), consolidated statements of cash flows and consolidated statements of shareholders' equity for the years ended December 31, 2021 and 2020, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2021 and 2020, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2021 and 2020 in accordance with International Financial Reporting Standards (IFRSs).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Consolidated Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. These matters were addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

Impairment and impairment reversal of property, plant and equipment.

As at December 31, 2021, the carrying value of property, plant and equipment (PP&E) was $2,269.7 million. For the year ended December 31, 2021, a net impairment reversal of $296.6 million was recorded with respect to PP&E. Refer to Note 1 for a description of the Company's impairment of non-financial assets accounting

To test the Company's estimated recoverable amount, we performed the following procedures, among others:

- Evaluated management's experts' competence, capability and objectivity as well as obtained an understanding of the work they performed. The appropriateness of their work as audit evidence policy. Refer to Note 5 for the Company's PP&E impairment disclosures. PP&E is tested for impairment or impairment reversal only when circumstances indicate that the carrying value of a cash generating unit (CGU) differs from the recoverable amount. Impairment or impairment reversal is determined by estimating a CGU's respective recoverable amount. The recoverable amount of the CGUs was based on expected after-tax future net cash flows from the production of proved and probable reserve volumes using forecast commodity prices and costs, discounted using market-based rates. Proved and probable reserves were determined by the Company's independent petroleum engineers (management's experts).

Auditing the Company's estimated recoverable amount was complex due to the subjective nature of the various management inputs and assumptions and the significant effect changes in these could have on the recoverable amount. Additionally, the evaluation of this estimate required specialized skills and knowledge. The primary inputs noted in the fair value less cost to sell model were the discount rate and after-tax future net cash flows from the production of proved plus probable reserve volumes.

was evaluated by considering the relevance and reasonableness of the methods and inputs.

- Involved our internal valuation specialists to assess the methodology applied and the various inputs utilized in determining the discount rate by referencing current industry, economic, and comparable company information, as well as company and cash-flow specific risk premiums.
- With the assistance of our internal valuation specialists, we also assessed the market capitalization to net assets and observed quantitative and qualitative reconciliations using market data and subsequent transactions.
- Compared forecast benchmark commodity price estimates of oil, natural gas, and NGLs against historically realized prices and to other third-party price forecasts.
- Assessed forecasted production, royalty, operating cost, and capital cost data by comparing it to historical performance of the Company.
- Evaluated the adequacy of the impairment and impairment reversal note disclosure included in Note 5 of the accompanying financial statements in relation to this matter.

Recoverability of deferred tax asset

The consolidated statement of financial position as at December 31, 2021 includes a deferred tax asset of $545.5 million. The deferred tax asset consists mainly of non-capital loss carry-forwards and deductible temporary differences related to scientific research and experimental development and asset retirement obligations. The recognition of deferred tax assets is based on management's judgement and estimate that it is probable taxable profit will be available against which these assets can be utilized. Refer to Note 1 for a description of the Company's tax accounting policy. Note 13 includes the disclosures for income taxes.

Auditing the Company's estimate of future taxable profit and the recoverability of the deferred tax asset was complex due to the subjective and sensitive nature of the various management inputs and assumptions. The primary inputs noted in the deferred tax asset recognition model were cash flows from the production of proved and probable reserves volumes, general and administrative expenditures and interest expenditures. The

To test the Company's estimated recoverability of deferred tax assets, we performed the following procedures, among others:

- Evaluated the competence, capability and objectivity of the independent reservoir engineering specialist engaged by the Company as well as obtained an understanding of the work they performed. The appropriateness of their work as audit evidence was evaluated by considering the relevance and reasonableness of the methods and inputs utilized.
- Compared forecast benchmark commodity price estimates of oil, natural gas, and NGLs against historically realized prices and to other third-party price forecasts.
- Assessed forecasted production, royalty, operating cost, and capital cost data by comparing it to historical performance of the Company.
- Involved our Canadian income tax specialists who assisted in evaluating the application of relevant tax laws and regulations used in the determination of the deferred income tax asset.
- With the support of our tax specialists, tax pool balances were agreed to the most recent tax

evaluation of this estimate required specialized skills and knowledge.

filings, and the tax rates used in determining the deferred tax balances were compared against the enacted or substantively enacted tax rates.

- Evaluated the adequacy of disclosure in Note 13 to the consolidated financial statements in respect of this matter.

Other Information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRSs, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor’s report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor’s report is Robert Troy Jubenvill.

Ernst + Young LLP

Chartered Professional Accountants

Calgary, Alberta
March 1, 2022

CONSOLIDATED BALANCE SHEETS

($ millions)

As at December 31	Note	2021	2020
ASSETS			
Current assets			
Cash and cash equivalents	17	**1.7**	4.6
Accounts receivable	14	**141.9**	100.0
Risk management – current	14	**5.8**	0.4
Prepaid expenses and other		**7.3**	9.9
		156.7	114.9
Lease receivable	9	**0.5**	2.8
Dissent payment entitlement	6	**–**	89.3
Investments in securities	7	**372.1**	59.5
Risk management – long-term	14	**0.7**	–
Exploration and evaluation	4	**539.9**	612.1
Property, plant and equipment, net	5	**2,269.7**	1,959.6
Deferred income tax	13	**545.5**	658.8
		3,885.1	3,497.0
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	14	**219.1**	152.8
Risk management – current	14	**6.5**	32.3
Asset retirement obligations and other – current	9	**30.4**	32.2
		256.0	217.3
Long-term debt	8	**386.3**	813.5
Risk management – long-term	14	**3.1**	19.4
Asset retirement obligations and other – long-term	9	**633.3**	409.0
		1,278.7	1,459.2
Commitments and contingencies	20		
Shareholders' equity			
Share capital	10	**2,251.9**	2,207.4
Accumulated deficit		**(15.5)**	(235.1)
Reserves	11	**370.0**	65.5
		2,606.4	2,037.8
		3,885.1	3,497.0

See the accompanying notes to these Consolidated Financial Statements

On behalf of the Board of Directors

/s/ J.H.T. Riddell
J.H.T. Riddell, Director

/s/ K. Lynch Proctor
K. Lynch Proctor, Director

March 1, 2022

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
($ millions, except as noted)

Year ended December 31	Note	2021	2020
Petroleum and natural gas sales		1,383.0	626.0
Royalties		(127.0)	(31.3)
Revenue	15	1,256.0	594.7
Gain (loss) on risk management contracts	14	(189.8)	8.9
		1,066.2	603.6
Expenses			
Operating expense		340.4	297.1
Transportation and NGLs processing		114.5	101.3
General and administrative		41.6	32.9
Share-based compensation	12	18.8	13.0
Depletion, depreciation and net impairment reversals	5	133.1	20.8
Exploration and evaluation	4	38.9	34.0
(Gain) loss on sale of oil and gas assets	5	(72.1)	8.7
Interest and financing		47.1	53.7
Accretion of asset retirement obligations	9	42.6	43.4
Transaction and reorganization costs		–	3.0
Settlement of dissent payment entitlement	6	22.6	–
Other	16	16.2	8.2
		743.7	616.1
Income (loss) before tax		322.5	(12.5)
Income tax expense			
Deferred	13	85.6	10.2
		85.6	10.2
Net income (loss)		236.9	(22.7)
Other comprehensive income (loss), net of tax	11		
Items that will be reclassified to net income (loss)			
Change in fair value of cash flow hedges, net of tax		8.9	(20.1)
Reclassification to net income (loss), net of tax		7.7	4.3
Items that will not be reclassified to net income (loss)			
Change in fair value of securities, net of tax	7	284.8	(15.9)
Comprehensive income (loss)		538.3	(54.4)
Net income (loss) per common share ($/share)	10		
Basic		1.77	(0.17)
Diluted		1.67	(0.17)

See the accompanying notes to these Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

($ millions)

Year ended December 31	Note	2021	2020
Operating activities			
Net income (loss)		236.9	(22.7)
Add (deduct):			
Items not involving cash	17	237.9	156.5
Asset retirement obligations settled	9	(25.4)	(35.0)
Change in non-cash working capital		32.7	(17.9)
Cash from operating activities		482.1	80.9
Financing activities			
Net draw (repayment) of revolving long-term debt	8	(430.2)	180.0
Lease liabilities – principal repayments	9	(7.7)	(7.5)
Convertible debentures issued, net of issue costs	8	34.9	–
Dividends	10	(27.4)	–
Common Shares issued, net of issue costs	10	10.6	–
Common Shares repurchased under NCIB	10	(2.7)	–
Common Shares purchased under restricted share unit plan	12	(10.8)	(4.1)
Cash from (used in) financing activities		(433.3)	168.4
Investing activities			
Capital expenditures	4,5	(274.6)	(220.2)
Land and property acquisitions	4,5	(5.4)	(0.6)
Proceeds of disposition	5,7	170.7	(0.5)
Investments	7	(1.0)	(11.7)
Proceeds from dissent payment entitlement, net	6	66.8	–
Change in non-cash working capital		(8.2)	(17.0)
Cash used in investing activities		(51.7)	(250.0)
Net decrease		(2.9)	(0.7)
Foreign exchange on cash and cash equivalents		–	(0.7)
Cash and cash equivalents, beginning of year		4.6	6.0
Cash and cash equivalents, end of year		1.7	4.6

See the accompanying notes to these Consolidated Financial Statements

Supplemental cash flow information 17

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions, except as noted)

Year ended December 31	Note	2021		2020	
		Shares (000's)		*Shares (000's)*	
Share capital					
Balance, beginning of year		*132,284*	2,207.4	*133,337*	2,207.5
Issued on exercise of Paramount Options	10	*1,504*	13.7	2	–
Issued on conversion of convertible debentures	8,10	*5,249*	35.5	–	–
Common Shares repurchased and cancelled under NCIB	10	*(198)*	(2.7)	–	–
Change in Common Shares under restricted share unit plan	12	*379*	(2.0)	*(1,055)*	(0.1)
Balance, end of year		*139,218*	2,251.9	*132,284*	2,207.4
Accumulated deficit					
Balance, beginning of year			(235.1)		(128.5)
Net income (loss)			236.9		(22.7)
Dividends			(27.4)		–
Recognition of deferred income tax asset	13		9.5		–
Reclassification of accumulated gain (loss) on securities	7,11		0.6		(83.9)
Balance, end of year			(15.5)		(235.1)
Equity component of convertible debentures	8,10				
Balance, beginning of year			–		–
Issued			1.7		–
Conversion of convertible debentures			(1.7)		–
Balance, end of year			–		–
Reserves	11				
Balance, beginning of year			65.5		4.2
Other comprehensive income (loss)			301.4		(31.7)
Contributed surplus			3.7		9.1
Reclassification of accumulated (gain) loss on securities	7		(0.6)		83.9
Balance, end of year			370.0		65.5
Total shareholders' equity			2,606.4		2,037.8

See the accompanying notes to these Consolidated Financial Statements

1. Significant Accounting Policies

Paramount Resources Ltd. ("Paramount" or the "Company") is an independent, publicly traded, liquids-focused Canadian energy company that explores for and develops both conventional and unconventional petroleum and natural gas. The Company also pursues longer-term strategic exploration and pre-development plays and holds a portfolio of investments in other entities. Paramount's principal properties are located in Alberta and British Columbia.

Paramount is the ultimate parent company of a consolidated group of companies and is incorporated and domiciled in Canada. The address of its registered office is 2800, 421 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 4K9. The consolidated group includes wholly-owned subsidiaries Fox Drilling Limited Partnership, Cavalier Energy Inc. ("Cavalier") and MGM Energy.

These consolidated financial statements of the Company, as at December 31, 2021 and 2020 and for the years then ended (the "Consolidated Financial Statements"), were authorized for issuance by Paramount's Board of Directors on March 1, 2022.

Basis of Preparation

These Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") on a historical cost basis, except for certain financial instruments. The Company's accounting policies have been applied consistently to all years presented. Amounts in these Consolidated Financial Statements are stated in millions of Canadian dollars, unless otherwise noted.

The financial statements of Paramount's subsidiaries and partnerships are prepared for the same reporting periods as the parent in accordance with the Company's accounting policies. All intercompany balances and transactions have been eliminated.

The preparation of these Consolidated Financial Statements requires the use of certain accounting estimates and also requires Management to exercise judgment in applying the Company's accounting policies. Areas involving a higher degree of judgment or complexity, and areas where assumptions and estimates are significant to the Consolidated Financial Statements, are described in Note 3.

a) Revenue Recognition

Revenue from petroleum and natural gas sales are recognized when control of the volumes produced is transferred to the purchaser, which generally occurs when the purchaser obtains the legal right to possession of such volumes, assumes the risks and rewards of ownership and payment from the purchaser is reasonably assured. From time-to-time, Paramount may exchange like commodities with other entities to facilitate its sales to purchasers and for other purposes. These non-monetary exchanges lack commercial substance and do not give rise to the separate recognition of revenues and expenses in the Company's Consolidated Statements of Comprehensive Income (Loss).

The Company accounts for its forward physical delivery sales contracts, which are entered into and continue to be held for the purpose of delivery of non-financial items as executory contracts, in accordance with expected sales requirements. These contracts are not considered derivative financial instruments. Settlements of these physical contracts are recognized in revenue over the term of the contracts as physical delivery occurs.

Revenue for drilling services is recognized when the performance of services has been completed and the Company has the right to collect consideration commensurate with the value of the services provided. When the Company's drilling rigs (the "Rigs") drill on a property owned by Paramount, the Company capitalizes its working interest share of the drilling expenses and eliminates the associated drilling revenue.

b) Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash in bank accounts and, from time to time, term deposits, certificates of deposit and other highly liquid investments.

c) Trade and Other Receivables

Accounts receivable are carried at amortized cost and are recorded as corresponding amounts of revenue are recognized or costs are incurred on behalf of partners in connection with joint operations.

d) Exploration and Evaluation

Costs related to the exploration for and evaluation of hydrocarbons, including costs of acquiring unproved properties, drilling and completing exploratory wells and estimated asset retirement costs, are initially capitalized, pending determination of technical feasibility and commercial viability. If hydrocarbons are found, but further appraisal activity is required to determine commercial viability, the exploration and evaluation ("E&E") costs continue to be recognized as an asset. All such costs are subject to technical, commercial, and Management review at least annually to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery.

When the technical feasibility and commercial viability of a project have been established, the E&E costs are transferred to petroleum and natural gas assets, subject to an impairment assessment. When the Company determines that an E&E project is no longer viable or its carrying value exceeds its recoverable amount, an impairment charge is recognized.

Exploratory geological and geophysical costs, pre-license costs, and annual lease rentals are expensed as incurred.

e) Property, Plant and Equipment

Petroleum and natural gas assets are carried at cost, net of accumulated depletion, depreciation and impairment, and include costs related to drilling and completing development wells, infrastructure construction, successful E&E projects and estimated asset retirement costs.

Paramount's Rigs are carried at cost, net of accumulated depreciation and impairment. Costs incurred to improve the capabilities of the Rigs, extend their useful lives or replace significant components are capitalized. When a significant component is replaced, the carrying value of the replaced component is written-off.

Other property, plant and equipment, including leasehold improvements, are carried at cost net of accumulated depreciation.

Depletion and Depreciation

The capitalized costs of developed oil and gas properties are depleted over estimated volumes of proved plus probable reserves using the unit-of-production method. In determining applicable depletion rates, estimated future development capital amounts ascribed to such reserves are included in the numerator. For purposes of these calculations, volumes of natural gas production and reserves are converted to barrels of oil equivalent using a ratio of six thousand cubic feet of natural gas to one barrel (6:1). Depletion rates are revised annually, or more frequently when events dictate. E&E assets are not depleted.

Capitalized costs of the majority of Paramount's production equipment and gathering systems are depleted on a unit-of-production basis over the volume of estimated proved plus probable reserves ascribed to the property to which they relate. Capitalized costs of processing plants and other major infrastructure assets are depreciated on a straight-line basis over their expected useful lives, which extend up to 40 years.

The Rigs are depreciated on a straight-line basis by component over their expected useful lives, which range between 5 and 20 years.

Leasehold improvements are depreciated over the term of the related lease. Other assets are depreciated using the declining balance method at rates ranging between 35 and 50 percent.

f) Impairment and Impairment Reversal of Non-Financial Assets

Carrying values of the Company's non-financial assets are reviewed at each reporting date to determine whether any indicators of impairment are present, or whether there are any indicators that an impairment loss recognized in prior periods may no longer exist or may have decreased. For the purpose of impairment testing, non-financial assets are generally grouped together into cash-generating units ("CGU"), which consist of the smallest group of assets that generate cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The Company's developed oil and gas properties have been grouped into four CGUs: Grande Prairie, Kaybob, Central Alberta and Northern. The Company's E&E assets, consisting mainly of undeveloped land, are aggregated together as a group of assets for the purpose of impairment testing.

If an indicator of impairment or impairment reversal is identified for a particular asset or CGU, its recoverable amount is estimated. If the carrying value of such asset or CGU exceeds its estimated recoverable amount, an impairment charge is recognized. If the estimated recoverable amount of an asset or CGU that was previously impaired exceeds its carrying value, impairment charges recognized in prior periods are reversed to a maximum of the carrying value that would have been determined, net of depletion and amortization, had no impairment charges been recognized for that CGU in prior periods.

The recoverable amount of an asset or CGU is the greater of its fair value less costs of disposal ("FVLCD") and its value in use ("VIU"). In assessing FVLCD, the Company estimates the value a potential purchaser would ascribe to an asset or CGU. For oil and gas properties, FVLCD is generally estimated based on expected after-tax future net cash flows from the production of proved plus probable reserves volumes using forecast commodity prices and costs, discounted using market-based rates. VIU is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU including an allocation of corporate costs.

g) Joint Arrangements

Paramount conducts its exploration and development activities independently, as well as jointly with others through jointly controlled assets and operations. All of the Company's current interests in joint arrangements are classified as joint operations. To account for these arrangements, Paramount recognizes its proportionate share of the revenues, expenses, assets and liabilities of such joint operations.

Interests in joint ventures are accounted for using the equity method of accounting. The Company does not currently have any interests in joint arrangements that are classified as joint ventures.

h) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting. Under this method, the net identifiable assets acquired are measured at fair value on the acquisition date, except for deferred income tax amounts. Any excess of the consideration paid over the value of the net identifiable assets acquired is recognized as goodwill. Any deficiency in the consideration transferred compared to the value of the net identifiable assets acquired is recognized in earnings. Costs incurred to complete the business combination are expensed.

i) Capitalized Borrowing Costs

Borrowing costs directly associated with the acquisition, construction or production of a qualifying asset are capitalized while the asset is being constructed or otherwise prepared for its intended productive use. All other borrowing costs are expensed in the period incurred.

j) Provisions

A provision is recognized where the Company has a present legal and/or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

A provision for onerous contracts is recognized when the expected economic benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting the obligations under the contract. The provision is measured at the lower of the expected cost of terminating the contract and the present value of the expected net cost of the contract over its remaining term.

k) Asset Retirement Obligations

Asset retirement obligations arise from legal and/or constructive obligations to retire assets, including oil and gas wells, gathering systems and facilities at the end of their productive lives. The present value of an asset retirement obligation is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of the cost of settlement can be made. The present value of the obligation is determined using the applicable credit-adjusted risk-free discount rate, after applying an estimated cost inflation factor, and is adjusted for the passage of time, which is recognized as accretion expense. The present values of estimated future asset retirement costs are capitalized as part of the carrying value of the related long-lived asset and depreciated on the same basis as the underlying asset. Revisions to the timing, anticipated cost, discount rate and inflation rate relating to the estimated liability are accounted for prospectively by recording an adjustment to the asset retirement obligation liability, with a corresponding adjustment to the carrying value of the related asset. Where changes to asset retirement obligations relate to properties which have a nil carrying value, the corresponding change is recorded in earnings.

Actual costs incurred on settlement are applied against the asset retirement obligation liability. Differences between the actual costs incurred and the liability accrued are recognized in earnings when the reclamation of a property is complete.

l) Foreign Currency Translation

The functional and presentation currency of Paramount and its subsidiaries is the Canadian dollar.

m) Estimates of Fair Value

Inputs used to estimate fair values incorporated in the preparation of the Consolidated Financial Statements are categorized into one of three levels of a fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. The three levels are defined as follows:

Level One – Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that can be accessed at the measurement date.

Level Two – Inputs are based on information other than quoted prices included within Level One that are observable for the asset or liability, either directly or indirectly, including:

a) quoted prices for similar assets or liabilities in active markets;

b) quoted prices for identical or similar assets or liabilities in markets that are not active;

c) inputs other than quoted prices that are observable for the asset or liability, for example:
   i. interest rates and yield curves observable at commonly quoted intervals;
   ii. implied volatilities; and
   iii. credit spreads; and

d) market-corroborated inputs.

Level Three – Inputs are unobservable. Unobservable inputs are developed using the best information available in the circumstances, which may incorporate Paramount's own internally generated data.

n) Financial Instruments and Other Comprehensive Income

Financial Instruments

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

Financial instruments are measured at fair value on initial recognition. The measurement of a financial instrument in subsequent periods is dependent upon whether it has been classified as "fair value through profit or loss", "fair value through other comprehensive income ("OCI")" or "amortized cost".

Paramount's risk management assets and liabilities relating to financial commodity and foreign currency exchange contracts are classified as fair value through profit or loss. Fair value through profit or loss financial instruments are measured at fair value, with changes in their fair values over time being recognized in net earnings. The fair values of the Company's risk management assets and liabilities relating to these instruments are estimated using a market approach incorporating level two fair value hierarchy inputs, including forward market curves and price quotes for similar instruments provided by financial institutions.

Investments in securities are classified as fair value through OCI. Financial assets that are classified as fair value through OCI are measured at fair value with changes in such fair values being accumulated in OCI until the asset is sold or derecognized. Upon the disposition or derecognition of an investment in securities, amounts previously recorded in OCI in respect of such investment are reclassified to retained earnings.

Investments in level one fair value hierarchy securities are carried at their period-end trading price (level one fair value hierarchy estimate). Estimates of fair values for investments in level three fair value hierarchy securities are based on valuation techniques that incorporate unobservable inputs (level three fair value hierarchy inputs). The valuation techniques utilize market-based metrics of comparable companies and transactions, indicators of value based on equity transactions of the entities and other indicators of value including financial and operational results of the entities. Fair value estimates of level three fair value hierarchy securities are updated at each balance sheet date to confirm whether the carrying value of the investment continues to fall within a range of possible fair values indicated by such techniques. Changes in assumptions, as well as changes in judgments regarding comparable transactions and entities, could result in a material change in the estimated fair values of investments in level three fair value hierarchy securities in future periods.

The Dissent Payment Entitlement as described in Note 6 was a financial instrument measured at amortized cost and was recorded based on the estimated fair value determined at the close of business on the day prior to the Company exercising its right of dissent, using valuation techniques and assumptions that incorporate unobservable inputs (level three fair value hierarchy inputs), including market-based metrics of comparable companies and transactions and other indicators of value.

Financial liabilities, including related transaction costs, are measured at amortized cost using the effective interest method.

Hedge Accounting

Paramount's risk management assets and liabilities related to floating-to-fixed interest rate and electricity swaps are accounted for as cash flow hedges using hedge accounting. The Company applies hedge accounting to certain financial instruments when such instruments are formally documented and designated at inception as qualifying hedging relationships. The documentation includes identification of the hedging instrument, the hedged item, the nature of the risk being hedged, the Company's risk management objective and strategy for undertaking the hedge and how the hedging relationship will be assessed to meet hedge effectiveness requirements.

Hedge effectiveness is evaluated by assessing the critical terms of the hedging relationship at inception, at the end of each reporting date and upon a significant change in the circumstances affecting hedge effectiveness. For a cash flow hedge, the effective portion of the change in the unrealized fair value of the hedging instrument is recognized in OCI. Accumulated gains or losses are reclassified from OCI to earnings as amounts are settled throughout the term of the arrangement. Any portion of the change in the fair value of the hedging instrument related to hedge ineffectiveness is recognized in earnings or reclassed from OCI to earnings when applicable.

Other Comprehensive Income

For Paramount, OCI is comprised of changes in the fair value of investments in securities and changes in the fair value of financial instruments where hedge accounting is applied (effective portion of hedge). Amounts recorded in OCI each period are presented in the Consolidated Statement of Comprehensive Income (Loss). Cumulative changes in OCI are included in Reserves, which is presented within Shareholders' Equity in the Consolidated Balance Sheet.

Compound Financial Instruments

Convertible debentures are compound financial instruments that contain both a liability and an equity component, which are initially recognized at fair value. The fair value of the liability component is determined on the date of issuance using the effective interest method, discounted using the estimated interest rate of a debt instrument having similar terms but without a conversion feature. The fair value of the conversion feature is determined on the date of issuance as the difference between the principal amount and the fair value of the liability component on the date of issue, and is classified within shareholders' equity. The liability component is carried at amortized cost and is accreted over the term of the convertible debentures to the principal amount using the effective interest method. This accretion, along with interest on the convertible debentures, is recorded as interest and financing expense. The equity component is not remeasured subsequent to initial recognition. The accreted liability and equity components are reclassified to share capital for convertible debentures that are converted into Common Shares.

o) Impairment of Financial Assets

The Company recognizes provisions for expected credit losses upon the initial recognition of financial assets and re-assesses the provision at each reporting date. The provision is adjusted as a result of changes in historical default rates, age of balances outstanding and counterparty credit metrics.

p) Income Taxes

Paramount follows the liability method of accounting for income taxes. Under this method, a deferred income tax asset or liability is recognized in respect of any temporary difference between the carrying amount of an asset or liability reported in the Consolidated Financial Statements and its respective tax basis, using substantively enacted income tax rates. Deferred income tax balances are adjusted to reflect changes in substantively enacted income tax rates expected to apply when the underlying assets are realized or liabilities are settled, with adjustments being recognized in deferred tax expense in the period in which the change occurs.

Deferred income tax assets are recognized to the extent future realization is considered probable. The carrying value of deferred income tax assets are reviewed at each reporting date taking into consideration historical and expected future taxable income, expected reversals of temporary differences, anticipated timing of realization, tax basis carry-forward periods and other factors. Deferred income tax assets are de-recognized to the extent that it is not probable that the carrying value of the asset will be realized.

q) Flow-Through Shares

The proceeds of flow-through share issuances are allocated between the sale of Paramount's class A common shares ("Common Shares") and the sale of tax benefits associated with the flow-through feature of the securities. Proceeds are first allocated to share capital based on the market price of Common Shares on the date the offering is priced, with the balance recorded as a liability based on the difference between the issue price and the market price of Common Shares. As qualifying expenditures intended for renunciation to subscribers are incurred, the Company recognizes a deferred tax liability, reduces the liability recorded and recognizes any difference as deferred tax expense.

r) Share-Based Compensation

Paramount Stock Option Plan

Paramount has a stock option plan that enables its Board of Directors or Compensation Committee to grant options to acquire Common Shares ("Paramount Options") to key employees and directors. Paramount Options generally vest over five years and expire within six years of the grant date. The provisions of the plan permit the Company to settle the Paramount Options in Common Shares of the Company or in cash.

The Company accounts for Paramount Options as equity-settled share-based compensation transactions. The aggregate grant date fair value of stock options awarded is recognized as share-based compensation expense over the applicable vesting period on a straight-line basis, with a corresponding increase in Contributed Surplus. The grant date fair value of Paramount Options is estimated using the Black-Scholes model, and such value is not adjusted in future periods. The amount of share-based compensation expense recognized each period reflects the portion of the vesting term that has elapsed and the estimated number of options that are expected to vest. That estimate is adjusted each period such that the cumulative amount recognized on the vesting date reflects the actual number of Paramount Options that ultimately vest. Upon the exercise of a Paramount Option, the Company transfers the cumulative amount recognized in Contributed Surplus in respect of that option to Share Capital.

Cavalier Stock Option Plan

Cavalier has a stock option plan that enables its Board of Directors to grant options to acquire common shares of Cavalier ("Cavalier Options") to key employees and directors. Cavalier Options generally vest over five years and expire within seven years of the grant date. The provisions of the stock option plan permit Cavalier to settle Cavalier Options in common shares of Cavalier or in cash, at the discretion of Cavalier. Cavalier Options are accounted for as equity-settled share-based compensation transactions.

Restricted Share Unit Plan

Paramount's cash bonus and restricted share unit ("RSU") plan provides that rights to Common Shares may be awarded to employees annually. An independent trustee purchases Common Shares in the open market and holds such shares until completion of the vesting period. Generally, the awards vest over two years. The unvested portion of an award is initially recorded as a reduction to Paramount's Share Capital. The cost of such awards is then recognized over the vesting period as share-based compensation expense, with a corresponding increase to Share Capital.

s) Net Income Per Share

Basic net income per share is calculated by dividing net income by the weighted average number of Common Shares outstanding during the year. Diluted net income per share is calculated by adjusting net income and the weighted average number of Common Shares outstanding for the effects of dilution related to Paramount Options and convertible debentures, as these instruments can be exchanged for Common Shares. For Paramount Options, the number of dilutive Common Shares is determined using the treasury stock method. For convertible debentures, net income is increased by the after-tax interest and finance expense on the convertible debentures and the number of diluted Common Shares are increased by shares issuable on conversion of the convertible debentures, when dilutive to the calculation of diluted net income per share.

t) Leases

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

Lessee

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

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

Lessor

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

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

u) Government Grants

Government grants are recognized when there is reasonable assurance that the relevant conditions of the grant are met and that the grant will be received. The Company records the grant in the Consolidated Financial Statements with the related expenditure in the period in which the eligible costs are incurred. Asset retirement obligation settlements approved for funding under government programs are recorded as a credit to earnings in depletion, depreciation and net impairment reversals in the period in which the related eligible costs are incurred.

2. New and Updated Accounting Policies and Standards

Adoption of Accounting Standards

Effective January 1, 2021, the Company adopted the phase two amendments to IFRS 9 – *Financial Instruments,* IAS 39 – *Financial Instruments: Recognition and Measurement*, IFRS 7 – *Financial Instruments: Disclosures,* IFRS 4 – *Insurance Contracts and* IFRS 16 – *Leases*. These amendments provide guidance in applying IFRS when there are changes to contractual cash flows or hedging relationships arising from the replacement of an interest rate benchmark with an alternative benchmark rate pursuant to the Interbank Offered Rate ("IBOR") reform. There has been no impact on the recognized assets, liabilities or comprehensive income (loss) of the Company resulting from the adoption of these amendments. The Company's floating-to-fixed interest rate swaps, which are described in Note 14, may be impacted by these amendments in the future as hedge accounting is applied to these instruments and hedging relationships may be impacted by the IBOR reform.

Future Changes in Accounting Standards

The IASB has announced amendments to accounting standards and interpretations and new accounting standards that are effective for annual periods beginning on or after January 1, 2022. These standards and interpretations have not been applied to the Consolidated Financial Statements. Paramount does not expect that these changes will have a material impact on the Company's Consolidated Financial Statements on adoption.

3. Significant Accounting Estimates, Assumptions & Judgments

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

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

A description of the accounting judgments, estimates and assumptions that are considered significant is set out below.

Exploration or Development

The Company is required to apply judgment when designating a project as E&E or development, including assessments of geological and technical characteristics and other factors related to each project.

Exploration and Evaluation Projects

The accounting for E&E projects requires Management to make judgments as to whether exploratory projects have discovered economically recoverable quantities of petroleum and natural gas, which requires the quantity and realizable value of such petroleum and natural gas to be estimated. Previous estimates are sometimes revised as new information becomes available. Where it is determined that an exploratory project did not discover economically recoverable petroleum and natural gas, the costs are written-off as E&E expense.

If hydrocarbons are encountered, but further appraisal activity is required, the exploratory costs remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the petroleum and natural gas is economically viable. The concept of "sufficient progress" is a judgmental area, and it is possible to have exploratory costs remain capitalized for several years while additional exploratory activities are carried out or the Company seeks government, regulatory or partner approval for development plans. E&E assets are subject to ongoing technical, commercial and Management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. Factors considered by Management in making this assessment may include: changes to project economics, expected quantities of petroleum and natural gas, expected production techniques, drilling results, estimated capital expenditures and production costs, results of other operators in the region and access to infrastructure and potential infrastructure expansions. Where it is determined that an exploratory project is not economically viable, the costs are written-off as E&E expense.

Reserves Estimates

Reserves engineering is an inherently complex and subjective process of estimating underground accumulations of petroleum and natural gas. The process relies on judgments based on the interpretation of available geological, geophysical, engineering and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of such data, the accuracy of various economic assumptions and the judgment of those preparing the estimate. Because these estimates depend on many assumptions, all of which may differ from actual results, reserves estimates, and estimates of future net revenue will be different from the sales volumes ultimately recovered and net revenues actually realized. Changes in market conditions, regulatory matters, the results of subsequent drilling, testing and production and other factors may result in revisions to the original estimates.

Estimates of reserves impact the assessment of whether a new well has found economically recoverable reserves, depletion rates, the estimated fair value of petroleum and natural gas properties acquired in a business combination and the estimated recoverable amount of petroleum and natural gas properties used for the purposes of impairment and impairment reversal assessments, all of which could have a material impact on earnings.

Business Combinations

Management is required to exercise judgment in determining whether assets acquired and liabilities assumed constitute a business. A business consists of an integrated set of assets and activities, comprised of inputs and processes, that is capable of being conducted and managed as a business by a market participant.

Business combinations are accounted for using the acquisition method of accounting, whereby the net identifiable assets acquired are recorded at fair value. The fair value of individual assets is often required to be estimated, which may involve estimating the fair values of proved plus probable reserves, contingent resources, tangible assets, undeveloped land, intangible assets and other assets. These estimates incorporate assumptions using indicators of fair value, as determined by Management. Changes in any of the estimates or assumptions used in determining the fair value of the net identifiable assets acquired may impact the carrying values assigned to assets acquired and liabilities assumed and could have a material impact on earnings.

Estimates of Recoverable Amounts

Estimates of recoverable amounts used in impairment and impairment reversal assessments often incorporate level three fair value hierarchy inputs, including estimated volumes and future net revenues from proved plus probable reserves, contingent resource estimates, future net cash flow estimates related to other long-lived assets and internal and external market metrics used to estimate fair value based on comparable assets and transactions. By their nature, such estimates are subject to measurement uncertainty. Changes in such estimates, and differences between actual and estimated amounts, could have a material impact on earnings.

Determination of CGUs

The recoverability of the carrying value of petroleum and natural gas assets is generally assessed at the CGU level. The determination of the properties and other assets grouped within a particular CGU is based on Management's judgment with respect to the integration between assets, shared infrastructure and cash flows, the overall significance of individual properties and the manner in which Management monitors its operations and allocates capital. Changes in the assets comprising CGUs could have an impact on estimated recoverable amounts used in impairment assessments and could have a material impact on earnings.

Depletion

Depletion rates are determined based on Management's estimates of the expected usage pattern of the Company's petroleum and natural gas assets, including assumptions regarding future production volumes, future development capital and the useful lives of production equipment and gathering systems.

Investments in Securities

The Company's investments in securities are accounted for as fair value through OCI financial assets. Management is required to exercise judgment in estimating the fair value of investments in the securities of corporations that are not publicly traded using available market inputs and other assumptions. Changes in estimates of fair value for such investments could have a material impact on comprehensive income.

Provisions

A provision is recognized where the Company has determined that it has a present obligation arising from past events and the settlement of the obligation is expected to result in an outflow of economic benefits. The determination of whether the Company has a present obligation arising from past events requires Management to exercise judgement as to the facts and circumstances of the event and the extent of any expected obligations of Paramount. Changes in facts and circumstances as a result of new information and other developments may impact Management's assessment of the Company's obligations, if any, in respect of such events. Changes in such estimates could have a material impact on Paramount's assets, liabilities, revenues, expenses and earnings.

Asset Retirement Obligations

Estimates of asset retirement costs are based on assumptions regarding the methods, timing, economic environment and regulatory standards that are expected to exist at the time assets are retired. Management also exercises judgment to determine the credit-adjusted risk-free discount rate at the end of each reporting period which may change in response to numerous market factors. The Company adjusts estimated amounts periodically as assumptions are updated to incorporate new information. The actual amount and timing of payments to settle the obligations may differ materially from estimates.

Share-Based Payments

The Company estimates the grant date fair value of stock options awarded using the Black-Scholes model. The inputs used to determine the estimated value of the options are based on assumptions regarding share price volatility, the life of the options, forfeiture rates, the risk-free interest rate and the dividend yield on the Common Shares. By their nature, these inputs are subject to measurement uncertainty and require Management to exercise judgment.

Income Taxes

Accounting for income taxes is a complex process requiring Management to interpret frequently changing laws and regulations and make judgments and estimates related to the application of tax law, the timing of temporary difference reversals and the likelihood of realizing deferred income tax assets. All tax filings are subject to subsequent government audits and potential reassessment. These interpretations and judgments, and changes related to them, impact current and deferred income tax provisions, the carrying value of deferred income tax assets and liabilities and could have a material impact on earnings.

4. Exploration and Evaluation

Year ended December 31	2021	2020
Balance, beginning of year	612.1	650.4
Additions	1.3	0.3
Acquisitions	8.9	3.0
Change in asset retirement provision	1.3	(0.7)
Transfers to property, plant and equipment	(14.0)	(8.8)
Expired lease costs	(29.8)	(25.5)
Dry hole	(1.1)	–
Dispositions	(38.8)	(6.6)
Balance, end of year	539.9	612.1

Exploration and Evaluation Expense

Year ended December 31	2021	2020
Geological and geophysical expense	8.0	8.5
Dry hole expense	1.1	–
Expired lease costs	29.8	25.5
	38.9	34.0

At December 31, 2021, the Company assessed its E&E assets for indicators of potential impairment or impairment reversal and none were identified.

5. Property, Plant and Equipment

Year ended December 31, 2021	Petroleum and natural gas assets	Drilling rigs	Right-of-use assets	Other	Total
Cost					
Balance, December 31, 2020	4,125.0	162.5	15.4	48.1	4,351.0
Additions	270.0	4.6	1.0	2.6	278.2
Acquisitions	1.0	–	–	–	1.0
Transfers from exploration and evaluation	14.0	–	–	–	14.0
Dispositions	(183.8)	–	(0.3)	–	(184.1)
Change in asset retirement provision	91.4	–	–	–	91.4
Cost, December 31, 2021	4,317.6	167.1	16.1	50.7	4,551.5
Accumulated depletion, depreciation and impairment					
Balance, December 31, 2020	(2,245.7)	(99.9)	(8.6)	(37.2)	(2,391.4)
Depletion and depreciation	(287.9)	(9.6)	(3.3)	(3.8)	(304.6)
Net impairment reversals	296.6	–	–	–	296.6
Dispositions	117.4	–	0.2	–	117.6
Accumulated depletion, depreciation and impairment, December 31, 2021	(2,119.6)	(109.5)	(11.7)	(41.0)	(2,281.8)
Net book value, December 31, 2020	1,879.3	62.6	6.8	10.9	1,959.6
Net book value, December 31, 2021	2,198.0	57.6	4.4	9.7	2,269.7

Year ended December 31, 2020	Petroleum and natural gas assets	Drilling rigs	Right-of-use assets	Other	Total
Cost					
Balance, December 31, 2019	3,996.1	161.2	16.0	46.7	4,220.0
Additions	220.1	1.4	(0.3)	1.9	223.1
Acquisitions	0.6	–	–	–	0.6
Transfers from exploration and evaluation	8.8	–	–	–	8.8
Dispositions	(35.8)	(0.1)	(0.3)	(0.5)	(36.7)
Change in asset retirement provision	(64.8)	–	–	–	(64.8)
Cost, December 31, 2020	4,125.0	162.5	15.4	48.1	4,351.0
Accumulated depletion, depreciation and impairment					
Balance, December 31, 2019	(2,177.7)	(89.9)	(5.3)	(33.0)	(2,305.9)
Depletion and depreciation	(238.7)	(10.1)	(3.6)	(4.7)	(257.1)
Net impairment reversals	141.9	–	–	–	141.9
Dispositions	28.8	0.1	0.3	0.5	29.7
Accumulated depletion, depreciation and impairment, December 31, 2020	(2,245.7)	(99.9)	(8.6)	(37.2)	(2,391.4)
Net book value, December 31, 2019	1,818.4	71.3	10.7	13.7	1,914.1
Net book value, December 31, 2020	1,879.3	62.6	6.8	10.9	1,959.6

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

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

Depletion, Depreciation and Net Impairment Reversals

Year ended December 31	2021	2020
Depletion and depreciation	**300.5**	253.9
Change in asset retirement obligations	**138.9**	(86.8)
Alberta site rehabilitation program funding	**(9.7)**	(4.4)
Net impairment reversals of petroleum and natural gas assets	**(296.6)**	(141.9)
	133.1	20.8

For the year ended December 31, 2021, the Company recorded a charge of $138.9 million (year ended December 31, 2020 a recovery of $86.8 million) to earnings related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value ascribed to property, plant and equipment. The changes mainly resulted from revisions in the credit-adjusted risk-free rate used to discount these obligations. A recovery was recorded for the year ended December 31, 2021 of $9.7 million (December 31, 2020 - $4.4 million) in respect of funding under the Alberta site rehabilitation program (see Note 9).

At December 31, 2021, the Company assessed its property, plant and equipment assets for indicators of potential impairment and none were identified.

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

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

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

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at September 30, 2021:[(1)]

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

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

At December 31, 2020, the Company recorded an aggregate of $333.7 million in reversals of previously recorded impairment charges, comprised of $287.7 million, $30.6 million and $15.4 million related to petroleum and natural gas assets in the Kaybob, Northern and Central Alberta CGUs, respectively. The impairment reversals resulted from an increase in the estimated recoverable amount of such CGUs compared to the prior impairment assessment performed at March 31, 2020.

The $333.7 million in aggregate impairment reversals represented the amount to bring the December 31, 2020 carrying values of the Kaybob and Northern CGUs to their estimated recoverable amounts and the December 31, 2020 carrying value of the Central Alberta CGU to the amount, net of depletion and amortization, had no impairment charges been recognized in prior periods. The increase in the estimated recoverable amount of these CGUs was mainly due to lower operating and capital costs than previously forecasted and changes to the development plan.

The recoverable amounts of the Kaybob, Northern and Central Alberta CGUs as at December 31, 2020 were estimated on a FVLCD basis, using a discounted cash flow method (level 3 fair value hierarchy estimate). After-tax cash flows were projected over the expected remaining productive life of the proved plus probable reserves assigned to the Kaybob, Northern and Central Alberta CGUs, at discount rates of 11.5 percent, 13.5 percent and 13.0 percent, respectively. Proved plus probable reserves estimates were prepared by Paramount's independent qualified reserves evaluator.

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at December 31, 2020: [(1)]

(Average for the period)	2021	2022	2023	2024	2025	2026-2033	Thereafter
Natural Gas [(2)]							
AECO ($/MMBtu)	2.78	2.70	2.61	2.65	2.70	2.76 – 3.16	+2%/yr
Henry Hub (US$/MMBtu)	2.83	2.87	2.90	2.96	3.02	3.08 – 3.53	+2%/yr
Crude Oil and Condensate [(2)]							
Edmonton Condensate ($/Bbl)	59.24	63.19	67.34	69.77	71.18	72.61 – 83.44	+2%/yr
WTI (US$/Bbl)	47.17	50.17	53.17	54.97	56.07	57.19 – 65.70	+2%/yr
Foreign Currency Exchange							
$US / 1 $CDN	0.77	0.77	0.76	0.76	0.76	0.76	0.76

(1) Average of forecasts published by: (i) McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. at January 1, 2021 and (ii) Sproule Associates Ltd. at December 31, 2020.
(2) Forecast benchmark prices are adjusted for quality differentials, heat content, distance to market and other factors in determining estimated recoverable amounts.

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

Recoverable amounts were estimated on a FVLCD basis using a discounted cash flow method (level three fair value hierarchy estimate). Cash flows were determined based on internally estimated after-tax discounted future net cash flows from the production of proved plus probable reserves assigned to the Kaybob and Northern CGUs, at discount rates of 11.5 percent and 13.5 percent, respectively. The after-tax net cash flows from the proved plus probable reserves estimated by Paramount's independent qualified reserves evaluator as at December 31, 2019 were mechanically updated by Management to reflect commodity price estimates at March 31, 2020 and for changes to certain operating and capital assumptions to reflect the prevailing economic environment.

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at March 31, 2020: [(1)]

	Apr-Dec 2020	2021	2022	2023	2024	2025-2032	Thereafter
Natural Gas [(2)]							
AECO ($/MMBtu)	1.74	2.20	2.38	2.45	2.53	2.60 – 3.04	+2%/yr
Henry Hub (US$/MMBtu)	2.10	2.58	2.79	2.86	2.93	3.00 – 3.45	+2%/yr
Crude Oil and Condensate [(2)]							
Edmonton Condensate ($/Bbl)	34.35	50.72	62.80	68.49	71.73	73.16 – 84.23	+2%/yr
WTI (US$/Bbl)	29.17	40.45	49.17	53.28	55.66	56.87 – 65.33	+2%/yr
Foreign Currency Exchange							
$US / 1 $CDN	0.71	0.73	0.75	0.75	0.75	0.75	0.75

(1) Average of forecasts published by: (i) McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. at April 1, 2020 and (ii) Sproule Associates Ltd. at March 31, 2020.
(2) Forecast benchmark prices are adjusted for quality differentials, heat content, distance to market and other factors in determining estimated recoverable amounts.

6. Dissent Payment Entitlement

As at December 31	2021	2020
Dissent Payment Entitlement	–	89.3

Paramount held 85 million common shares of Strath Resources Ltd. ("Strath") prior to its amalgamation with Cona Resources Ltd. in August 2020 to form Strathcona Resources Ltd. ("Strathcona"). Paramount objected to the amalgamation and exercised its right of dissent under section 191 of the *Business Corporations Act* (Alberta) with respect to its Strath shares. As a result, the Company became entitled to be paid in cash the fair value of its Strath shares, determined as of the close of business on July 24, 2020 (the "Dissent Payment Entitlement"), which Paramount originally estimated to be $89.3 million.

The amount of the Dissent Payment Entitlement and the timing of the payment thereof were uncertain. Paramount initially applied to the Court of Queen's Bench of Alberta seeking Strathcona's payment of the Dissent Payment Entitlement. Strathcona made a statutorily required offer with respect to the Dissent Payment Entitlement in the amount of $45 million. Paramount rejected such offer and ultimately received $67 million cash in 2021 in settlement of the dissent proceedings and for the sale of its remaining securities in Strathcona. A loss of $22.6 million was recognized on the settlement.

7. Investments in Securities

As at December 31	2021	2020
Level one fair value hierarchy securities	300.2	48.4
Level three fair value hierarchy securities	71.9	11.1
	372.1	59.5

For the year ended December 31, 2021, the Company recorded $316.8 million, before tax, to other comprehensive income as a result of changes in the estimated fair values of investments in level one fair value hierarchy securities ("Level One Securities") and investments in level three fair value hierarchy securities ("Level Three Securities").

In 2020, the Company acquired 17.3 million common shares of NuVista Energy Ltd. ("NuVista Shares") at a price of $0.61 per share for an aggregate purchase price of $10.6 million. At December 31, 2021, the Company owned a total of 39.8 million NuVista Shares having a carrying value of $276.7 million, which were included in Investments in Securities and classified as Level One Securities.

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

Year ended December 31	2021	2020
Investments in securities, beginning of year	59.5	156.9
Changes in fair value of Level One Securities – recorded in OCI	256.0	(50.6)
Changes in fair value of Level Three Securities – recorded in OCI	60.8	32.5
Transfer to Dissent Payment Entitlement (see Note 6)	–	(89.3)
Derecognition of warrants	(0.1)	–
Changes in fair value of warrants – recorded in earnings	0.1	(1.7)
Acquired	1.0	11.7
Proceeds of dispositions	(5.2)	–
Investments in securities, end of year	372.1	59.5

8. Long-Term Debt

As at December 31	2021	2020
Paramount Facility [(1)]	386.3	813.5

(1) Presented net of $2.8 million in unamortized transaction costs (December 31, 2020 - $2.2 million).

Paramount Facility

The Company has a $900 million financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility"). The maturity date of the Paramount Facility is June 2, 2024. At Paramount's request, the credit limit of the Paramount Facility can be increased to $1.0 billion pursuant to an accordion feature in the facility, subject to incremental lender commitments.

Borrowings under the Paramount Facility bear interest at the prime lending rate, US base rate, CDOR, or LIBOR, as selected by the Company, plus an applicable margin which varies based on the Company's Senior Secured Debt to Consolidated EBITDA ratio. The Paramount Facility is secured by a charge over substantially all of the assets of the Company and its subsidiaries.

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

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

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

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

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

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

Paramount was in compliance with the financial covenants under the Paramount Facility at December 31, 2021.

The Company had undrawn letters of credit outstanding under the Paramount Facility totaling $2.3 million at December 31, 2021 that reduce the amount available to be drawn on the facility.

Unsecured Letter of Credit Facility

The Company has a $70 million unsecured demand revolving letter of credit facility (the "LC Facility") with a Canadian bank. Paramount's obligations under the LC Facility are supported by a performance security guarantee ("PSG") from Export Development Canada ("EDC"). The PSG is valid to June 30, 2022 and may be extended from time-to-time with the agreement of EDC. At December 31, 2021, $38.7 million in undrawn letters of credit were outstanding under the LC Facility (December 31, 2020 – $40.7 million).

Convertible Debentures

In January 2021, the Company completed a private placement of $35.0 million of senior unsecured convertible debentures (the "Convertible Debentures"). An entity controlled by Paramount's President and Chief Executive Officer and Chairman purchased $25.0 million of the Convertible Debentures. The Convertible Debentures had a maturity date of January 31, 2024 (the "Maturity Date"), bore interest at 7.50 percent per annum and were convertible by the holder into Common Shares at any time prior to the Maturity Date. On the issuance date of the Convertible Debentures, the conversion prices were $6.72 per Common Share prior to January 31, 2022, $7.33 per Common Share on or after January 31, 2022 and prior to January 31, 2023 and $7.94 per Common Share on or after January 31, 2023. These prices were subject to customary anti-dilution adjustments.

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

In November 2021, Paramount delivered notices to redeem all $35.0 million of the Convertible Debentures effective December 3, 2021 (the "Redemption Date"). Prior to the Redemption Date, all holders exercised their right to convert their Convertible Debentures into Common Shares. An aggregate of 5,249,019 Common Shares were issued on conversion of the debentures, including 3.8 million Common Shares issued on conversion of $25.0 million principal amount of debentures by an entity controlled by Paramount's President and Chief Executive Officer and Chairman. For the year ended December 31, 2021, $2.2 million in interest payments were made on the Convertible Debentures.

9. Asset Retirement Obligations and Other

As at December 31, 2021	Current	Long-term	Total
Asset retirement obligations	20.4	630.7	**651.1**
Lease liabilities	10.0	2.6	**12.6**
Asset retirement obligations and other	**30.4**	**633.3**	**663.7**

As at December 31, 2020	Current	Long-term	Total
Asset retirement obligations	22.2	397.3	419.5
Lease liabilities	10.0	11.7	21.7
Asset retirement obligations and other	**32.2**	**409.0**	**441.2**

Asset Retirement Obligations

Year ended December 31	2021	2020
Asset retirement obligations, beginning of year	419.5	569.9
Additions	1.3	0.5
Change in estimates	23.8	(7.6)
Change in discount rate	206.4	(145.2)
Obligations settled – cash	(25.4)	(35.0)
Obligations settled – funding under the Alberta site rehabilitation program	(9.7)	(4.4)
Dispositions	(7.4)	(2.1)
Accretion expense	42.6	43.4
Asset retirement obligations, end of year	651.1	419.5

As at December 31, 2021, estimated undiscounted, uninflated asset retirement obligations were $1,318.7 million (December 31, 2020 – $1,351.7 million). Asset retirement obligations have been determined using a credit-adjusted risk-free discount rate of 7.0 percent (December 31, 2020 – 11.0 percent) and an inflation rate of 2.0 percent (December 31, 2020 – 2.0 percent). These obligations are expected to be settled over the next 50 years.

Lease Liabilities

Paramount has lease liabilities in respect of office space and vehicles, which have been recognized at the discounted value of the remaining fixed lease payments. As at December 31, 2021 a weighted average incremental borrowing rate of approximately 5.4 percent (December 31, 2020 – 5.6 percent) was used to determine the discounted amount of the liabilities. For the year ended December 31, 2021, total cash payments made in respect of these lease liabilities, net of sublease arrangements, were $8.4 million (2020 - $8.6 million), of which $0.7 million (2020 - $1.1 million) was recognized as interest and financing expense.

For the year ended December 31, 2021, expenses related to arrangements containing variable operating costs, short-term and low value leases which have not been included in the lease liability were approximately $2.5 million (2020 - $3.3 million).

As at December 31, 2021, $2.7 million (December 31, 2020 - $5.1 million) is due to the Company in respect of sublease arrangements for a portion of Paramount's office space, of which $2.2 million (December 31, 2020 - $2.3 million) was classified as current and $0.5 million (December 31, 2020 - $2.8 million) was classified as non-current. For the year ended December 31, 2021, $2.6 million (2020 - $2.6 million) was received in respect of office sublease arrangements, of which $0.2 million (2020 - $0.4 million) was recognized as interest revenue.

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

	Lease Payments	Sublease Receivables
2022	10.4	2.4
2023	2.2	0.5
2024 to 2025	0.4	–
	13.0	2.9

10. Share Capital

Paramount's authorized share capital consists of an unlimited number of Common Shares without par value and an unlimited number of preferred shares, issuable in series. At December 31, 2021, 139.2 million (December 31, 2020 – 132.3 million) Common Shares of the Company were outstanding, net of 1.5 million (December 31, 2020 – 1.9 million) Common Shares held in trust under the RSU plan, and no preferred shares were outstanding.

In June 2021, Paramount announced the implementation of a regular monthly dividend with respect to its Common Shares. Dividends declared for the year ended December 31, 2021 totaled $27.4 million or $0.20 per Common Share. Subsequent to December 31, 2021, the Company has paid $16.9 million or $0.12 per Common Share in regular monthly dividends.

In June 2021, Paramount implemented a normal course issuer bid program (the "NCIB") under which the Company may purchase up to 7.3 million Common Shares for cancellation. The NCIB will terminate on the earlier of June 29, 2022 and the date on which the maximum number of Common Shares that can be acquired pursuant to the NCIB are purchased. Purchases of Common Shares under the NCIB will be effected through the facilities of the TSX or alternative Canadian trading systems at the market price at the time of purchase. The Company repurchased and cancelled 197,500 Common Shares at a total cost of $2.7 million under the NCIB to December 31, 2021.

For the year ended December 31, 2021, Paramount issued 5.2 million Common Shares on conversion of the Convertible Debentures (see Note 8) and 1.5 million Common Shares on the exercise of Paramount Options (see Note 12).

Weighted Average Common Shares

Year ended December 31	2021		2020	
	Wtd. Avg Shares (000's)	**Net income**	*Wtd. Avg Shares (000's)*	Net loss
Net income (loss) – basic	***133,619***	**236.9**	*133,347*	(22.7)
Dilutive effect of Convertible Debentures	***4,763***	**2.2**	–	–
Dilutive effect of Paramount Options	***4,453***	**–**	–	–
Net income (loss) – diluted	***142,835***	**239.1**	*133,347*	(22.7)

Outstanding Paramount Options and Convertible Debentures that can be exchanged for Common Shares are potentially dilutive and are included in Paramount's diluted per share calculations when they are dilutive to net income per share. For the year ended December 31, 2021, 3.8 million Paramount Options were anti-dilutive (December 31, 2020 – 9.7 million).

11. Reserves

Reserves at December 31, 2021 include unrealized losses on cash flow hedges, unrealized gains and losses related to changes in the market value of investments in securities and contributed surplus amounts in respect of Paramount Options and Cavalier Options.

For the year ended December 31, 2020, accumulated losses of $83.9 million were reclassified from accumulated OCI to accumulated deficit, including $69.9 million related to the Company's exercise of its Strath dissent rights (see Note 6) and the derecognition of an investment classified as a Level One Security.

The changes in reserves are as follows:

Year ended December 31, 2021	Unrealized gains (losses) on cash flow hedges	Unrealized gains (losses) on securities	Contributed surplus	Total reserves
Balance, beginning of year	(21.9)	(79.7)	167.1	**65.5**
Other comprehensive income, before tax	21.7	316.8	–	**338.5**
Deferred tax	(5.1)	(32.0)	–	**(37.1)**
Reclassification of accumulated gain on securities	–	(0.6)	–	**(0.6)**
Share-based compensation (see Note 12)	–	–	6.8	**6.8**
Paramount Options exercised	–	–	(3.1)	**(3.1)**
Balance, end of year	**(5.3)**	**204.5**	**170.8**	**370.0**

Year ended December 31, 2020	Unrealized gains (losses) on cash flow hedges	Unrealized gains (losses) on securities	Contributed surplus	Total reserves
Balance, beginning of year	(6.1)	(147.7)	158.0	**4.2**
Other comprehensive loss, before tax	(20.6)	(18.1)	–	**(38.7)**
Deferred tax	4.8	2.2	–	**7.0**
Reclassification of accumulated loss on securities (see Note 6)	–	83.9	–	**83.9**
Share-based compensation (see Note 12)	–	–	9.1	**9.1**
Paramount Options exercised	–	–	–	–
Balance, end of year	**(21.9)**	**(79.7)**	**167.1**	**65.5**

12. Share-Based Compensation

Paramount Options

	2021		2020	
	Number	**Weighted average exercise price ($/share)**	***Number***	**Weighted average exercise price ($/share)**
Balance, beginning of year	***9,681,395***	**6.91**	*12,311,462*	12.16
Granted	***3,205,000***	**16.31**	*3,111,500*	3.82
Exercised (1)	***(1,503,724)***	**7.03**	*(2,000)*	7.28
Cancelled or forfeited	***(309,346)***	**8.49**	*(4,366,829)*	17.97
Expired	***(41,800)***	**15.97**	*(1,372,738)*	11.82
Balance, end of year	***11,031,525***	**9.55**	*9,681,395*	6.91
Options exercisable, end of year	***2,713,661***	**9.23**	*2,416,871*	9.74

(1) For Paramount Options exercised during the twelve months ended December 31, 2021, the weighted average market price of Paramount's Common Shares on the dates exercised was $17.05 (2020 – $7.77).

The weighted average remaining contractual life and exercise prices of Paramount Options outstanding as at December 31, 2021 are as follows:

	Awards Outstanding			Exercisable		
Exercise Prices	**Number**	**Remaining contractual life (years)**	**Weighted average exercise price**	**Number**	**Remaining contractual life (years)**	**Weighted average exercise price**
$1.64 – $6.99	4,288,270	4.0	4.63	769,970	3.8	4.94
$7.00 – $15.99	3,003,756	2.8	7.41	1,376,692	2.8	7.38
$16.00 – $25.50	3,739,499	4.6	16.90	566,999	0.8	19.52
	11,031,525	**3.8**	**9.55**	**2,713,661**	2.7	**9.23**

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

	Options awarded in 2021	**Options awarded in 2020**
Weighted average exercise price ($ / share)	**16.31**	3.82
Volatility (%)	**44**	50
Expected life of share options (years)	**4.3**	3.9
Pre-vest annual forfeiture rate (%)	**12.9**	13.2
Risk-free interest rate (%)	**0.8**	0.4
Dividend yield (%)	**1.5**	Nil
Weighted average fair value of awards per option ($ / option)	**5.18**	1.43

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

Cavalier Options

In 2017, Cavalier granted 5.0 million Cavalier Options, which vest over five years and expire approximately eight years from the grant date. As at December 31, 2021, there were 3.7 million Cavalier Options outstanding and no Cavalier Options have been exercised.

Restricted Share Units – Shares Held in Trust

	2021		2020	
Year ended December 31	***Shares (000's)***		***Shares (000's)***	
Balance, beginning of year	***1,915***	**1.5**	*860*	1.4
Shares purchased	***1,088***	**10.8**	*1,600*	4.1
Change in vested and unvested shares	***(1,467)***	**(8.8)**	*(545)*	(4.0)
Balance, end of year	***1,536***	**3.5**	*1,915*	1.5

Employee Benefit Costs

Year ended December 31	2021	2020
Stock option plans	6.8	9.1
RSU plan	12.0	3.9
Share-based compensation expense	18.8	13.0
Salaries and benefits, net of recoveries	30.6	22.6
	49.4	35.6

13. Income Tax

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

Year ended December 31	2021	2020
Income (loss) before tax	322.5	(12.5)
Effective Canadian statutory income tax rate	23.1%	24.1%
Expected income tax expense (recovery)	74.5	(3.0)
Effect on income taxes of:		
Change in statutory and other rates	2.2	4.2
Share-based compensation	1.6	2.2
(Gain) loss on sale of oil and gas assets	(0.1)	0.4
Settlement of dissent payment entitlement	2.6	–
Change in unrecognized deferred income tax asset	0.5	4.7
Flow-through share renunciations	–	3.6
Non-deductible items and other	4.3	(1.9)
Income tax expense	85.6	10.2

The following table summarizes the components of the deferred income tax asset:

As at December 31	2021	2020
Property, plant and equipment	(412.8)	(302.4)
Investments in securities	(32.5)	(0.5)
Asset retirement obligations	149.4	96.5
Non-capital losses and scientific research & experimental development	821.4	843.5
Other	20.0	21.7
Deferred income tax asset	545.5	658.8

The following table summarizes movements in the deferred income tax asset during the year:

Year ended December 31	2021	2020
Deferred income tax asset, beginning of year	658.8	663.5
Deferred income tax expense	(85.6)	(10.2)
Deferred income tax (expense) recovery included in OCI	(37.1)	7.0
Deferred income tax recovery recognized in accumulated deficit	9.5	–
Flow-through share renunciations	–	(1.4)
Other	(0.1)	(0.1)
Deferred income tax asset, end of year	545.5	658.8

For the year ended December 31, 2021, the Company recognized $82.0 million of deductible temporary differences for which no deferred income tax asset had been previously recorded as a result of taxable temporary differences arising in the year in respect of investments in securities. The deferred income tax asset was increased by $9.5 million, the tax effected amount of such temporary differences, and the accumulated deficit was reduced by a corresponding amount as the previously unrecognized temporary differences relate to disposed or derecognized investments in securities.

As at December 31, 2021, Paramount had approximately $3.3 billion (December 31, 2020 – $3.4 billion) of unused non-capital losses that expire between 2032 and 2036. The Company has $35.5 million (December 31, 2020 – $160.7 million) of deductible temporary differences for which no deferred income tax asset has been recorded.

14. Financial Instruments and Risk Management

Financial Instruments

Financial instruments at December 31, 2021 consist of accounts receivable, risk management assets and liabilities, investments in securities, accounts payable and the Paramount Facility. The carrying values of these financial instruments approximate their fair values.

Risk Management

From time-to-time, Paramount enters into derivative financial instruments to manage commodity price, interest rate and foreign currency exchange risks.

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

Changes in the fair value of the risk management asset and liability for the year ended December 31, 2021 are as follows:

Year ended December 31, 2021	Financial Commodity Contracts	Foreign Currency Exchange Contracts	Interest Rate Swaps	Electricity Swaps	Total
Fair value of asset (liability), December 31, 2020	(22.7)	–	(29.0)	0.4	(51.3)
Changes in fair value – profit or loss (1)	(190.1)	0.3	(1.9)	–	(191.7)
Changes in fair value – OCI	–	–	11.6	2.5	14.1
Risk management contract settlements (received) paid (2)	218.2	0.1	9.7	(2.2)	225.8
Fair value of asset (liability), December 31, 2021	5.4	0.4	(9.6)	0.7	(3.1)
Risk management asset – current	5.4	0.4	–	–	5.8
Risk management asset – long-term	–	–	–	0.7	0.7
Risk management asset, December 31, 2021	5.4	0.4	–	0.7	6.5
Risk management liability – current	–	–	(6.5)	–	(6.5)
Risk management liability – long-term	–	–	(3.1)	–	(3.1)
Risk management liability, December 31, 2021	–	–	(9.6)	–	(9.6)

(1) Changes in fair value of ($189.8) million relate to financial commodity and foreign currency exchange contracts, which are recorded as gain (loss) on risk management contracts. Changes in fair value of ($1.9) million relate to hedge ineffectiveness on interest rate swaps, which is recorded in interest and financing.
(2) Payments on risk management contract settlements related to financial commodity and foreign currency exchange contracts totaled $218.3 million. Risk management contract settlements relating to interest rate swap and electricity swap contracts are recorded in interest and financing and operating expenses, respectively.

Changes in the fair value of the risk management asset and liability for the year ended December 31, 2020 are as follows:

Year ended December 31, 2020	Financial Commodity Contracts	Interest Rate Swaps	Electricity Swaps	Total
Fair value of asset (liability), December 31, 2019	6.0	(8.0)	–	(2.0)
Changes in fair value – profit or loss	8.9	–	–	8.9
Changes in fair value – OCI	–	(26.6)	0.4	(26.2)
Risk management contract settlements (received) paid (1)	(37.6)	5.6	–	(32.0)
Fair value of asset (liability), December 31, 2020	(22.7)	(29.0)	0.4	(51.3)
Risk management asset – current	–	–	0.4	0.4
Risk management asset, December 31, 2020	–	–	0.4	0.4
Risk management liability – current	(22.7)	(9.6)	–	(32.3)
Risk management liability – long-term	–	(19.4)	–	(19.4)
Risk management liability, December 31, 2020	(22.7)	(29.0)	–	(51.7)

(1) Receipts on risk management contract settlements related to financial commodity contracts totaled $37.6 million. Risk management contract settlements relating to interest rate swap contracts are recorded in interest and financing.

The Company had the following risk management contracts at December 31, 2021:

Instruments	Aggregate notional	Average price or rate	Remaining term
Financial Commodity Contracts (1)			
Oil – NYMEX WTI Swaps (Sale)	9,500 Bbl/d	CDN$87.90/Bbl	January 2022 – March 2022
Oil – NYMEX WTI Swaps (Sale)	3,500 Bbl/d	CDN$91.38/Bbl	April 2022 – December 2022
Oil – NYMEX WTI Swaps (Sale)	3,500 Bbl/d	US$75.79/Bbl	January 2022 – December 2022
Gas – NYMEX Swaps (Sale)	40,000 MMBtu/d	US$4.15/MMBtu	January 2022 – March 2022
Oil – NYMEX WTI Collars	7,000 Bbl/d	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)	January 2022 – December 2022
Foreign Currency Exchange Contracts			
Swaps	US$5 million / month	1.27 C$ / US$1.00	January 2022 – December 2022
Collars	US$5 million / month	1.25 C$ / US$1.00 (Floor) 1.30 C$ / US$1.00 (Ceiling)	January 2022 – November 2022
Interest Rate Contracts (2)			
Swaps	$250 million	2.3%	January 2022 – January 2023
Swaps	$250 million	2.4%	January 2022 – January 2026
Electricity Contracts (3)			
Swaps	120 MWh/d (4)	$62.50/MWh	January 2023 – December 2023
Swaps	120 MWh/d (4)	$53.25/MWh	January 2024 – December 2024

(1) "WTI" means West Texas Intermediate and "NYMEX" means New York Mercantile Exchange.
(2) Reference interest rate: Canadian Dollar Offered Rate.
(3) Reference electricity rate: Floating hourly rate established by the Alberta Electric System Operator ("AESO Pool Price").
(4) "MWh" means megawatt-hour.

Subsequent to December 31, 2021, the Company entered into the following financial commodity contracts:

Instruments	Aggregate notional	Average fixed price	Remaining term
Gas – NYMEX Swaps (Sale)	30,000 MMBtu/d	US$4.62/MMBtu	April 2022 – June 2022
Gas – NYMEX Swaps (Sale)	30,000 MMBtu/d	US$4.67/MMBtu	July 2022 – September 2022
Gas – NYMEX Swaps (Sale)	10,000 MMBtu/d	US$4.91/MMBtu	October 2022

The Company has classified its floating-to-fixed interest and electricity swap arrangements as cash flow hedges and applied hedge accounting. At December 31, 2021, $150 million of floating-to-fixed interest rate swaps were de-designated as cash flow hedges due to declines in borrowings under the Paramount Facility, resulting in $1.9 million of unrealized losses being reclassified from other comprehensive income to interest and financing expense. There were no other changes to the critical terms of the hedging relationships and no hedge ineffectiveness was identified on the floating-to-fixed electricity swaps.

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

Commodity Price Risk

Paramount uses financial commodity contracts from time-to-time to manage exposure to commodity price volatility. The Company is exposed to commodity price risk on these instruments, as changes in underlying commodity prices impact the market values of the contracts and ultimately the amounts received or paid upon settlement.

The following table summarizes the sensitivity of the fair value of Paramount's financial commodity contracts outstanding at December 31, 2021 to independent fluctuations in commodity prices, with all other variables held constant. The impact of fluctuating commodity prices on the Company's December 31, 2021 open financial commodity contract positions would have resulted in an unrealized gain (loss) impacting income (loss) before income tax as follows: (1)

	Increase in Commodity Price		Decrease in Commodity Price	
	WTI Crude Oil	NYMEX Henry Hub	WTI Crude Oil	NYMEX Henry Hub
Income (loss) before income tax	(34.8)	(2.3)	33.7	2.3

(1) Sensitivities are based on a US$5.00 per barrel increase or decrease in the price of WTI crude oil and a US$0.50 per MMBtu increase or decrease in the price of NYMEX Henry Hub natural gas, assuming all other variables are constant.

Foreign Currency Exchange Risk

Paramount uses foreign currency exchange contracts from time-to-time to manage risks of volatility in foreign currency exchange rates related to its U.S. dollar denominated petroleum and natural gas sales revenue.

The following table summarizes the sensitivity of the fair value of Paramount's financial commodity contracts, foreign currency exchange contracts and U.S. dollar denominated financial instruments outstanding at December 31, 2021 to independent fluctuations in foreign currency exchange rates, with all other variables held constant. The impact of fluctuating foreign currency exchange rates on the Company's December 31, 2021 open financial commodity and foreign currency exchange contract positions and the U.S. dollar denominated financial instruments would have resulted in an unrealized gain (loss) impacting income (loss) before income tax as follows: (1)

	Increase in C$/US$ Foreign Currency Exchange Rate	Decrease in C$/US$ Foreign Currency Exchange Rate
Income (loss) before income tax	(22.4)	21.9

(1) Sensitivities are based on a C$0.06 increase or decrease in the December 31, 2021 C$/US$ foreign currency exchange rate, assuming all other variables are constant.

Credit Risk

Paramount is exposed to credit risk on its financial instruments where a loss would be experienced if a counterparty to a financial asset failed to meet its obligations. The maximum credit risk exposure at December 31, 2021 is limited to the carrying value of accounts receivable and risk management assets.

Paramount's primary objectives with respect to financial assets are to minimize financial risk and maintain high levels of liquidity. The Company's risk management assets are held with financial institutions with investment grade credit ratings. Accounts receivable include balances due from customers and partners in the oil and gas industry and are subject to normal industry credit risk. The Company manages credit risk by endeavoring to sell its production to and enter into risk management contracts with counterparties that possess high credit ratings, employing net settlement agreements and obtaining letters of credit and limiting available credit when necessary. The change in the fair value of risk management contracts attributable to changes in counterparty credit risk is immaterial, as the counterparties to such contracts have investment grade credit ratings.

Interest Rate Risk

Paramount is exposed to interest rate risk on outstanding balances on the Paramount Facility and on interest bearing cash and cash equivalents. From time-to-time, the Company may enter into interest rate swaps to manage exposure to changes in interest rates on long-term debt.

The following table summarizes the sensitivity of the fair value of Paramount's floating-to-fixed interest rate swaps outstanding at December 31, 2021 to independent fluctuations in interest rates, with all other variables held constant. The impact of fluctuating interest rates on the Company's December 31, 2021 open floating-to-fixed interest rate swap contract positions would have resulted in an immaterial impact to net income (loss) and an unrealized gain (loss) impacting OCI as follows: (1)

	Increase in Interest Rate	Decrease in Interest Rate
Other comprehensive income, net of tax	8.3	(7.9)

(1) Sensitivities are based on a one percent increase or decrease in the CDOR interest rate, assuming all other variables are constant.

Liquidity Risk

Liquidity risk is the risk that Paramount will be unable to meet its financial obligations as they become due. The Company manages liquidity risk by ensuring that it has sufficient cash and cash equivalents, credit facilities and other financial resources available to meet its obligations.

The Company regularly updates its forecasts of short-term and longer-term cash flows to identify financial requirements. These requirements are met through a combination of cash flows from operating activities, cash and cash equivalents, and if required, credit facilities, the sale of assets and capital market transactions.

The Company's contractual obligations related to financial liabilities are as follows: (1)

	2022	2023	2024	Total
Accounts payable & accrued liabilities	219.1	–	–	219.1
Paramount Facility	–	–	389.1	389.1
	219.1	–	389.1	608.2

(1) Excludes lease liabilities (see Note 9) and risk management liabilities.

Accounts Payable and Accrued Liabilities

As at December 31	2021	2020
Trade and accrued payables	209.9	149.1
Joint operation and other payables	9.2	3.7
	219.1	152.8

Trade and accrued payables and joint operation and other payables are non-interest bearing and are normally settled within 30 to 60 days.

Accounts Receivable

As at December 31	2021	2020
Revenue receivable	118.1	72.9
Joint operation receivable and other	23.8	27.1
	141.9	100.0

Revenue, joint operation and other receivables are non-interest bearing and are generally settled within 30 days. Accounts receivable that share similar credit risk characteristics are assessed for expected credit losses at each reporting date, including for changes in historical default rates, ages of balances outstanding and counterparty credit metrics. The total expected credit loss on the Company's accounts receivable was approximately 3 percent as at December 31, 2021 (December 31, 2020 – 5 percent).

For the year ended December 31, 2021, the Company had sales to one customer totaling $340.6 million, which exceeded ten percent of total revenue. The customer had an investment grade credit rating.

15. Revenue By Product

Year ended December 31	2021	2020
Natural gas	373.3	204.9
Condensate and oil	926.5	383.8
Other natural gas liquids	78.6	24.7
Royalty and other	4.6	12.6
Royalties	(127.0)	(31.3)
	1,256.0	594.7

16. Other

Year ended December 31	2021	2020
Change in fair value of securities – warrants	(0.1)	1.7
Provisions	24.0	4.7
Settlements	(7.0)	–
Other	(0.7)	1.8
	16.2	8.2

Provisions

For the year ended December 31, 2021, the Company recorded provisions of $24.0 million with respect to arrangements with a service provider. The Company has unsettled claims of a greater amount against the same service provider with respect to certain related matters, which have not been recognized. The outcome of all of these matters remains uncertain.

In the first quarter of 2020, a provision of $4.7 million was recorded related to a pending partner dispute.

Settlements

In the fourth quarter of 2021, Paramount recognized $7.0 million, net of legal fees, in connection with the settlement of outstanding litigation relating to damages to a well.

17. Consolidated Statements of Cash Flows – Selected Information

Items Not Involving Cash

Year ended December 31	2021	2020
Risk management contracts	(28.5)	28.7
Share-based compensation	18.8	13.0
Depletion, depreciation and net impairment reversals	133.1	20.8
Exploration and evaluation	30.9	25.5
(Gain) loss on sale of oil and gas assets	(72.1)	8.7
Accretion of asset retirement obligations	42.6	43.4
Settlement of dissent payment entitlement	22.6	–
Change in fair value of securities - warrants	(0.1)	1.7
Deferred income tax	85.6	10.2
Other	5.0	4.5
	237.9	156.5

Supplemental Cash Flow Information

Year ended December 31	2021	2020
Interest paid	36.7	47.8

Components of Cash and Cash Equivalents

As at December 31	2021	2020
Cash	1.7	4.6
Cash equivalents	–	–
	1.7	4.6

18. Capital Structure

Paramount's capital structure consists of shareholders' equity plus net debt.

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

i. ensure liquidity to fund ongoing operations and capital programs, the settlement of obligations when due and the payment of regular monthly dividends;

ii. preserve financial flexibility and access to capital markets, including for the pursuit of strategic initiatives; and

iii. maximize shareholder returns considering the risk environment.

Paramount monitors and assesses its capital structure for alignment with its current and long-term business plans and will, guided by its primary capital management objectives, seek to adjust the structure as necessary in response to changes in its business plans, plans for shareholder returns, economic and operating conditions, financial and operating results, strategic initiatives and the Company's assessment of the risk environment. Paramount may adjust its capital structure through a number of means, including by modifying capital spending programs, seeking to issue or repurchase shares, altering debt levels, modifying dividend levels or acquiring or disposing of assets.

The key capital management measures used by the Company in monitoring and assessing its capital structure are net debt, adjusted funds flow, the ratio of net debt to adjusted funds flow and free cash flow.

The use and composition of each of these measures is described below. These measures are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities.

Net Debt

Net debt, in conjunction with capacity under existing credit facilities, is used to monitor and assess liquidity by providing Management and investors with a measure of the Company's overall leverage position.

The calculation of net debt is as follows:

As at December 31	2021	2020
Cash and cash equivalents	**(1.7)**	(4.6)
Accounts receivable [(1)]	**(139.7)**	(97.7)
Prepaid expenses and other	**(7.3)**	(9.9)
Accounts payable and accrued liabilities	**219.1**	152.8
Long-term debt	**386.3**	813.5
Net Debt	**456.7**	854.1

(1) Accounts receivable excludes amounts relating to subleases (December 31, 2021 – $2.2 million, December 31, 2020 – $2.3 million).

Adjusted Funds Flow

Adjusted funds flow is used to monitor and assess liquidity and the flexibility of the Company's capital structure by providing Management and investors with a measure of the cash flows generated by the Company's assets available to fund capital programs and meet financial obligations, including the settlement of asset retirement obligations.

The calculation of adjusted funds flow is as follows:

Year ended December 31	2021	2020
Cash from operating activities	**482.1**	80.9
Change in non-cash working capital	**(32.7)**	17.9
Geological and geophysical expense	**8.0**	8.5
Asset retirement obligations settled	**25.4**	35.0
Closure costs	**–**	–
Provisions	**24.0**	4.7
Settlements	**(7.0)**	–
Transaction and reorganization costs	**–**	3.0
Adjusted funds flow	**499.8**	150.0

Net Debt to Adjusted Funds Flow Ratio

The ratio of net debt to adjusted funds flow is used to monitor and assess liquidity and the flexibility of the Company's capital structure by showing the relation of the cash flows generated by the Company's assets to its overall leverage position.

The net debt to adjusted funds flow ratio is calculated as the period end net debt divided by adjusted funds flow for the trailing four quarters.

	2021	2020
Net debt, as at December 31	456.7	854.1
Adjusted funds flow, trailing four quarters ended December 31	499.8	150.0
Net debt to adjusted funds flow ratio, December 31	**0.9x**	5.7x

For the year ended December 31, 2021, Paramount targeted a net debt to adjusted funds flow ratio of 1.0x. Paramount has reduced its targeted leverage level to approximately $300 million in net debt, implying a targeted net debt to adjusted funds flow ratio of less than 0.5x for the year ended December 31, 2022.

Free Cash Flow

Free cash flow is used to monitor and assess liquidity, the flexibility of the Company's capital structure and the financial capacity to maximize shareholder returns by providing Management and investors with a measure of the internally generated cash available, after funding capital programs and asset retirement obligation settlements, to service the Company's financial obligations, pay dividends, repurchase Common Shares and fund additional growth opportunities.

The calculation of free cash flow is as follows:

Year ended December 31	2021	2020
Cash from operating activities	482.1	80.9
Change in non-cash working capital	(32.7)	17.9
Geological and geophysical expense	8.0	8.5
Asset retirement obligations settled	25.4	35.0
Closure costs	–	–
Provisions	24.0	4.7
Settlements	(7.0)	–
Transaction and reorganization costs	–	3.0
Adjusted funds flow	499.8	150.0
Capital expenditures	(274.6)	(220.2)
Geological and geophysical expense	(8.0)	(8.5)
Asset retirement obligations settled	(25.4)	(35.0)
Free cash flow	191.8	(113.7)

19. Compensation of Key Management Personnel

Year ended December 31	2021	2020
Salaries and benefits	1.9	2.1
Share-based compensation	3.8	1.5
	5.7	3.6

20. Commitments and Contingencies

Paramount had the following commitments as at December 31, 2021:

	Within one year	After one year but not more than five years	More than five years
Petroleum and natural gas transportation and processing commitments (1)	236.1	889.0	999.0
Other commitments (2)	18.2	27.1	26.7
	254.3	**916.1**	**1,025.7**

(1) Certain of the transportation and processing commitments are secured by outstanding letters of credit totaling $13.0 million at December 31, 2021 (December 31, 2020 – $13.2 million).
(2) Includes future commitments of $34 million relating to a new long-term lease expected to commence in June 2022.

Commitments – Physical Sale Contracts

The Company had the following fixed-price and basis differential physical contracts at December 31, 2021:

	Volume	Location	Average price	Remaining term
Natural gas	40,000 GJ/d	AECO	CDN$4.06/GJ	January 2022 – March 2022
Natural gas	30,000 GJ/d	AECO	CDN$3.54/GJ	April 2022 – October 2022
Condensate	2,098 Bbl/d	FSPL (1)	WTI + US$3.13/Bbl	January 2022 – March 2022

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

Subsequent to December 31, 2021, the Company entered into the following fixed-price and basis differential physical contracts:

	Volume	Location	Average price	Remaining term
Natural gas	50,000 GJ/d	AECO	CDN$3.92/GJ	April 2022 – October 2022
Natural gas	20,000 MMBtu/d	Dawn	US$4.03/MMBtu	April 2022 – October 2022
Peace sweet crude oil	5,186 Bbl/d	Peace (1)	WTI – US$2.15/Bbl	April 2022 – June 2022

(1) Peace refers to the Peace Pipeline at Edmonton.

Contingencies

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

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

PRODUCT TYPE INFORMATION

This document 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.

	Annual							
	Total		Grande Prairie Region		Kabob Region		Central Alberta and Other Region	
	2021	2020	2021	2020	2021	2020	2021	2020
Shale gas (MMcf/d)	207.9	156.7	138.8	77.2	38.6	43.8	30.5	35.7
Conventional natural gas (MMcf/d)	67.3	92.0	2.2	1.4	58.6	82.1	6.5	8.5
Natural gas (MMcf/d)	275.2	248.7	141.0	78.6	97.2	125.9	37.0	44.2
Condensate (Bbl/d)	28,328	19,334	25,253	15,991	2,295	2,885	781	458
Other NGLs (Bbl/d)	5,147	4,325	3,103	1,964	1,612	1,812	432	549
NGLs (Bbl/d)	33,475	23,659	28,356	17,955	3,907	4,697	1,213	1,007
Tight oil (Bbl/d)	487	462	–	–	355	301	131	161
Light and Medium crude oil (Bbl/d)	2,174	2,768	5	14	2,129	2,709	40	46
Crude oil (Bbl/d)	2,661	3,230	5	14	2,484	3,010	171	207
Total (Boe/d)	82,001	68,340	51,869	31,076	22,588	28,685	7,544	8,579

	Annual			
	Karr		Wapiti	
	2021	2020	2021	2020
Shale gas (MMcf/d)	107.9	55.6	31.0	21.5
Conventional natural gas (MMcf/d)	1.3	0.7	0.6	0.4
Natural gas (MMcf/d)	109.2	56.3	31.6	21.9
NGLs (Bbl/d)	20,188	11,389	8,159	6,550
Total (Boe/d)	38,381	20,777	13,432	10,207

	Q4							
	Total		Grande Prairie Region		Kabob Region		Central Alberta and Other Region	
	2021	2020	2021	2020	2021	2020	2021	2020
Shale gas (MMcf/d)	220.4	170.7	156.5	92.7	35.6	41.9	28.2	36.1
Conventional natural gas (MMcf/d)	64.4	85.6	2.4	1.6	56.8	76.3	5.3	7.7
Natural gas (MMcf/d)	284.8	256.3	158.9	94.3	92.4	118.2	33.5	43.8
Condensate (Bbl/d)	29,797	22,782	26,272	19,635	2,184	2,631	1,341	515
Other NGLs (Bbl/d)	5,462	4,987	3,276	2,429	1,788	1,953	398	605
NGLs (Bbl/d)	35,259	27,769	29,548	22,064	3,972	4,584	1,739	1,120
Tight oil (Bbl/d)	497	437	–	–	355	299	142	138
Light and Medium crude oil (Bbl/d)	2,048	2,533	6	–	2,000	2,480	42	54
Crude oil (Bbl/d)	2,545	2,970	6	–	2,355	2,779	184	192
Total (Boe/d)	85,265	73,460	56,035	37,782	21,725	27,056	7,505	8,622

	Q4			
	Karr		Wapiti	
	2021	2020	2021	2020
Shale gas (MMcf/d)	122.5	69.6	34.1	22.8
Conventional natural gas (MMcf/d)	1.5	0.9	0.6	0.5
Natural gas (MMcf/d)	124.0	70.5	34.7	23.3
NGLs (Bbl/d)	20,970	15,165	8,568	6,875
Total (Boe/d)	41,629	26,914	14,350	10,764

Fourth quarter 2021 sales volumes at Karr averaged 41,629 Boe/d (122.5 MMcf/d of shale gas, 1.5 MMcf/d of conventional natural gas and 20,970 Bbl/d of NGLs), compared to 39,878 Boe/d (113.0 MMcf/d of shale gas, 1.4 MMcf/d of conventional natural gas and 20,805 Bbl/d of NGLs) in the third quarter of 2021. Fourth quarter 2021 sales volumes at Wapiti averaged 14,350 Boe/d (34.1 MMcf/d of shale gas, 0.6 MMcf/d of conventional natural gas and 8,568 Bbl/d of NGLs), compared to 14,651 Boe/d (32.7 MMcf/d of shale gas, 0.6 MMcf/d of conventional natural gas and 9,100 Bbl/d of NGLs) in the third quarter of 2021.

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, netback including risk management contract settlements and F&D capital 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) less royalties, operating expense and transportation and NGLs processing expense. 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 Company's producing assets after incorporating management's risk management strategies.

Refer to the table under the heading "Financial and Operating Results" in this document for the calculation of netback and netback including risk management contract settlements for the years ended December 31, 2021 and 2020 and for the three months ended December 31, 2021 and 2020.

F&D capital is a measure used in determining F&D costs and is comprised of capital expenditures (the most directly comparable measure disclosed in the Company's primary financial statements) for the year excluding corporate expenditures plus the change from the prior year in estimated future development capital included in the reserves evaluation prepared by McDaniel. F&D capital is used by management and investors, in calculating F&D costs, to represent the amount of capital invested in oil and gas exploration and development projects to generate reserves additions.

Set out below is the calculation of F&D capital for the years ended December 31, 2021 and 2020. Prior period results have been restated to conform with the current years' presentation to reflect the inclusion of changes in estimated future development capital in the calculation of F&D capital.

($ millions)	Grande Prairie Region (1)		Total Company (1)	
Proved Developed Producing	**2021**	2020	**2021**	2020
Capital expenditures	**229**	197	**275**	221
Corporate expenditures	**–**	–	**(6)**	(2)
Change in estimated future development capital	**(22)**	(4)	**(11)**	54
F&D Capital	**207**	193	**257**	273
Total Proved	**2021**	2020	**2021**	2020
Capital expenditures	**229**	197	**275**	221
Corporate expenditures	**–**	–	**(6)**	(2)
Change in estimated future development capital	**(182)**	(736)	**221**	(962)
F&D Capital	**47**	(539)	**490**	(743)
Proved Plus Probable	**2021**	2020	**2021**	2020
Capital expenditures	**229**	197	**275**	221
Corporate expenditures	**–**	–	**(6)**	(2)
Change in estimated future development capital	**(197)**	(1,106)	**(93)**	(1,196)
F&D Capital	**31**	(909)	**176**	(977)

(1) Columns may not add due to rounding.

Non-GAAP Ratios

F&D costs, recycle ratio, netback and netback including risk management contract settlements presented on a $/Boe of $/Mcf basis are non-GAAP ratios as they each have a non-GAAP financial measure 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.

F&D costs are calculated by dividing: (i) F&D capital (a non-GAAP financial measure) for the applicable reserves category; by (ii) the net changes to reserves in such reserves category from the prior year from extensions/improved recovery, technical revisions and economic factors. F&D 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. Readers should refer to the information under the heading "Reserves and Other Oil and Gas Information – Reserves Reconciliation" in the Company's annual information form for the year ended December 31, 2021, which is available on www.sedar.com or at www.paramountres.com, for a description of the net changes to reserves in each reserves category from the prior year. See "Advisories – Oil and Gas Definitions and Measures" for more information about this measure.

Recycle ratio is calculated by dividing the netback (a non-GAAP financial measure) per Boe for the year by the F&D costs for the year. Recycle ratio is used by investors and management to compare the cost of adding reserves to the netback realized from production. See "Advisories – Oil and Gas Definitions and Measures" for more information about this measure.

Set out below, for comparative purposes to the 2021 information included in this document, are the applicable F&D costs and recycle ratios for 2020. Prior period results have been restated to conform with the current years' presentation to reflect the inclusion of changes in estimated future development capital in the calculation of F&D capital.

	F&D ($/Boe)		Recycle Ratio (x)	
	Total	**Grande Prairie**	**Total**	**Grande Prairie**
Proved Developed Producing	**$7.90**	$8.79	**1.0x**	1.3x
Total Proved	**na**	na	**na**	na
Proved plus Probable	**na**	na	**na**	na

Netback on a $/Boe of $/Mcf basis is calculated by dividing netback (a non-GAAP financial measure) for the applicable period by the total production during the period in Boe or Mcf. Netback including risk management contract settlements on a $/Boe of $/Mcf basis is calculated by dividing netback including risk management contract settlements for the applicable period by the total production during the period in Boe or Mcf. 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, net debt and net debt to adjusted funds flow 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 18 – Capital Structure in the Consolidated Financial Statements 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 years ended December 31, 2021 and 2020 and (iii) a calculation of net debt as at December 31, 2021 and 2020.

The following is a reconciliation of adjusted funds flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements, for the three months ended December 31, 2021 and 2020:

Three months ended December 31	**2021**	2020
Cash from operating activities	**191.8**	53.2
Change in non-cash working capital	**(20.1)**	12.5
Geological and geophysical expense	**2.9**	2.1
Asset retirement obligations settled	**7.0**	0.1
Closure costs	**–**	–
Provisions	**–**	–
Settlements	**(7.0)**	–
Transaction and reorganization costs	**–**	–
Adjusted funds flow	**174.6**	67.9

The following is a reconciliation of 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 December 31, 2021 and 2020:

Three months ended December 31	2021	2020
Cash from operating activities	**191.8**	53.2
Change in non-cash working capital	**(20.1)**	12.5
Geological and geophysical expense	**2.9**	2.1
Asset retirement obligations settled	**7.0**	0.1
Closure costs	**–**	–
Provisions	**–**	–
Settlements	**(7.0)**	–
Transaction and reorganization costs	**–**	–
Adjusted funds flow	**174.6**	67.9
Capital expenditures	**(65.7)**	(65.1)
Geological and geophysical expense	**(2.9)**	(2.1)
Asset retirement obligation settled	**(7.0)**	(0.1)
Free cash flow	**99.0**	0.6

For comparative purposes to the 2021 information included in this document, net debt to adjusted funds flow as at December 31, 2020 was 5.7x.

Supplementary Financial Measures

This document 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 and transportation and NGLs processing expenses 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 and transportation and NGLs processing expenses on a $/Bbl, $/Mcf or $/Boe basis are calculated by dividing the revenue, petroleum and natural gas sales, royalties, operating expenses or transportation and NGLs processing expenses, 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 document constitute forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "anticipate", "believe", "estimate", "will", "expect", "plan", "schedule", "intend", "propose", or similar words suggesting future outcomes or an outlook. Forward-looking information in this document includes, but is not limited to:

- planned capital expenditures in 2022;
- forecast sales volumes for 2022 and certain periods therein;
- the expectation that well outperformance in 2022 will offset the impact of the unplanned outages at the third-party operated Wapiti natural gas processing facility;
- forecast free cash flow in 2022;
- the Company's priorities and expectations respecting the allocation of free cash flow;
- the expectation that the Company will achieve its net debt target of about $300 million in the third quarter of 2022;
- the expectation that plateau production will be reached at Wapiti in 2023;
- planned abandonment and reclamation expenditures and activities in 2022;
- preliminary anticipated capital expenditures in 2023 and the resulting expected 2023 average sales volumes and free cash flow;
- the Company's five-year outlook for capital spending, annual production growth rate and cumulative free cash flow;
- planned exploration, development and production activities, including the expected timing of drilling, completing and bringing new wells on production;
- the expectation that the Company will realize capital cost efficiencies in its Kaybob Duvernay plays similar to those achieved at Karr and Wapiti: and
- the payment of future dividends under the Company's monthly dividend program.

Statements relating to reserves are also deemed to be forward looking information, 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.

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

- future commodity prices;
- 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 document, 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;
- 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 document is made as of the date hereof and, except as required by applicable securities law, Paramount undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Certain forward-looking information in this document, 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 document. Such assumptions are based on management's assessment of the relevant information currently available and any financial outlook included in this document 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.

Reserves Data

Reserves data set forth in this document is based upon an evaluation of the Company's reserves prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") dated March 1, 2022 and effective December 31, 2021 (the "McDaniel Report"). The price forecast used in the McDaniel Report is an average of the January 1, 2022 price forecasts for McDaniel and GLJ Petroleum Consultants Ltd. and the December 31, 2021 price forecast of Sproule Associates Ltd. The estimates of reserves contained in the McDaniel Report and referenced in this document 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 document. 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, 2021, which is available on SEDAR at www.sedar.com, for a complete description of the McDaniel Report (including reserves by the specific product types 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

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

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

Natural Gas	
GJ	Gigajoules
GJ/d	Gigajoules per day
MMBtu	Millions of British Thermal Units
MMBtu/d	Millions of British Thermal Units per day
Mcf	Thousands of cubic feet
MMcf	Millions of cubic feet
MMcf/d	Millions of cubic feet per day
AECO	AECO-C reference price
WTI	West Texas Intermediate

This document 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, 2021, the value ratio between crude oil and natural gas was approximately 24:1. 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 document 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 document. The metrics are F&D costs, recycle ratio, reserves replacement ratio and CGR. 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.

Refer to the "Specified Financial Measures" section of this document for a description of the calculation and use of F&D costs and recycle ratio. 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 exploration and development. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. CGR is a measure commonly used by management and investors to assess the relative liquids production from a well.

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.

CORPORATE INFORMATION

EXECUTIVE OFFICERS

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

P. R. Kinvig
Chief Financial Officer

B. K. Lee
Executive Vice President, Finance

D. B. Reid
Executive Vice President, Operations

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

J. B. Williams
Executive Vice President, Kaybob Region

DIRECTORS

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

J. G. M. Bell (1) (3) (4)
President and Chief Executive Officer
Dominion Lending Centres Inc.
Calgary, Alberta

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

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

K. Lynch Proctor (1) (4) (5)
Independent Businesswoman
Calgary, Alberta

R. M. MacDonald (1) (3) (4)
Independent Businessman
Oakville, Ontario

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

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

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

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Calgary, Alberta
Toronto, Ontario

RESERVES EVALUATORS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

AUDITORS

Ernst & Young LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
(“POU”)