2022 Annual Results

Paramount Resources Ltd. Announces Record 2022 Annual Results

Calgary, Alberta – March 7, 2023

Paramount Resources Ltd. ("Paramount" or the "Company") (TSX:POU) is pleased to report 2022 annual financial and operating results highlighted by record production, adjusted funds flow and free cash flow and substantial reserves additions.

HIGHLIGHTS

- The Company achieved record annual sales volumes of 88,672 Boe/d (45% liquids) in 2022. Fourth quarter sales volumes averaged 97,370 Boe/d (45% liquids), of which 64,434 Boe/d (51% liquids) was produced in the Grande Prairie Region. (1)
- Cash from operating activities was a record $1,050 million ($7.45 per basic share) in 2022 and $307 million ($2.17 per basic share) in the fourth quarter. (2)
- Adjusted funds flow in 2022 was $1,171 million ($8.32 per basic share) and $341 million ($2.40 per basic share) in the fourth quarter, representing annual and quarterly records for the Company. (2)
- Capital expenditures in 2022, which included the pre-ordering of approximately $25 million in materials for future development, totaled $655 million versus the $640 million upper range of prior guidance.
- The Company generated record annual free cash flow in 2022 of $471 million ($3.35 per basic share) compared to prior guidance of $500 million. Fourth quarter free cash flow was $162 million ($1.14 per basic share), also a quarterly record. (2)
- Total proved ("TP") reserves increased 31% to 445 MMBoe with an NPV_{10} of approximately $5.8 billion ($41.18 per basic share). Proved plus probable ("P+P") reserves increased 15% to 759 MMBoe with an NPV_{10} of approximately $9.1 billion ($64.52 per basic share). (3)
- Three-year average finding and development ("F&D") costs were $7.72/Boe for TP reserves and $4.24/Boe for P+P reserves. (4)

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

(2) Adjusted funds flow and free cash flow are capital management measures used by Paramount. Cash from operating activities per basic share, adjusted funds flow per basic share and free cash flow per basic share are supplementary financial measures. Refer to the "Specified Financial Measures" section for more information on these measures.

(3) All reserves are gross reserves based upon an evaluation prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") dated March 6, 2023 and effective December 31, 2022 (the "McDaniel Report"). "NPV_{10}" refers to the net present value of future net revenue of the applicable reserves, discounted at 10 percent, as estimated in the McDaniel Report. Such value does not represent fair market value. Readers are referred to the advisories concerning "Reserves Data".

(4) F&D costs are a non-GAAP ratio. Refer to the "Specified Financial Measures" section and "Oil and Gas Measures and Definitions" in the Advisories section for more information on this measure and on the related non-GAAP financial measure of F&D capital. The three-year average F&D costs were calculated by dividing total F&D capital over the period by the aggregate reserves additions in the period.

- Paramount continued to successfully execute its strategy of accretive acquisitions and divestitures in 2022 and early 2023. The Company more than tripled its Willesden Green Duvernay land position in two acquisitions at a total cost of $98 million and realized compelling value for its Kaybob Smoky and Kaybob South Duvernay properties and a portion of its road infrastructure in dispositions that generated aggregate proceeds of $434 million.
- Paramount continues to deliver on its free cash flow priorities:
  - The Company achieved its net debt target of $300 million in October 2022 and then further reduced net debt to $161 million at year end, representing a $296 million year-over-year reduction. (1)
  - Paramount more than doubled its regular monthly dividend in 2022 to $0.125 per class A common share ("Common Share").
  - In January 2023, the Company paid a special cash dividend of $1.00 per Common Share and repaid all remaining drawings under its $1.0 billion revolving credit facility. At January 31, 2023, Paramount had a cash balance of approximately $110 million.
- The carrying value of the Company's investments in securities at December 31, 2022 was $557 million.

2022 RESERVES

- Proved developed producing ("PDP") reserves increased 28% year-over-year to 160 MMBoe. TP reserves were up 31% to 445 MMBoe. P+P reserves increased 15% to 759 MMBoe.
  - In the Grande Prairie Region, where the majority of 2022 development activity occurred, PDP reserves were up 33% year-over-year, TP reserves were up 35% and P+P reserves were up 10%.
- With the significant reserves additions in 2022, the Company's reserves replacement ratios were 1.9x for PDP reserves, 4.0x for TP reserves and 3.7x for P+P reserves. (2)
- Compared to 2021, the NPV_{10} of the Company's:
  - PDP reserves increased 75% to $2.5 billion ($17.82 per basic share);
  - TP reserves increased 62% to $5.8 billion ($41.18 per basic share); and
  - P+P reserves increased 46% to $9.1 billion ($64.52 per basic share).
- 2022 F&D costs were: (3)
  - $9.58/Boe for PDP reserves (4.5x recycle ratio);
  - $14.11/Boe for TP reserves (3.0x recycle ratio); and
  - $14.87/Boe for P+P reserves (2.9x recycle ratio).
- Three-year average F&D costs were: (4)
  - $8.13/Boe for PDP reserves (3.4x recycle ratio);
  - $7.72/Boe for TP reserves (3.5x recycle ratio); and
  - $4.24/Boe for P+P reserves (6.5x recycle ratio).

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(1) Net debt is a capital management measure used by Paramount. Refer to the "Specified Financial Measures" section for more information on this measure.
(2) 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.
(3) 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 and on the related non-GAAP financial measure of F&D capital.
(4) The three-year average F&D costs were calculated by dividing total F&D capital over the period by the aggregate reserves additions in the period. The associated recycle ratios were calculated by dividing the weighted average netback, a non-GAAP measure, per Boe over the period by the three-year average F&D costs.

REVISED GUIDANCE

Paramount is reaffirming its 2023 and preliminary 2024 sales volumes guidance, as well as its five-year outlook for sales volumes. Paramount is increasing its 2023 guidance for capital expenditures by $50 million as a result of anticipated inflationary cost pressures. The Company is reaffirming its preliminary 2024 guidance and five-year outlook for capital expenditures. Capital expenditures in 2023 and 2024 are expected to be evenly split between: (i) sustaining and maintenance capital; and (ii) growth. Paramount is revising its free cash flow expectations to reflect lower natural gas prices, updated capital expenditures in 2023 and revised foreign exchange rates and other assumptions.

2023 Guidance

Annual average sales volumes (Boe/d)	100,000 to 105,000 (46% liquids)
First half average sales volumes (Boe/d)	96,000 to 101,000 (45% liquids)
Second half average sales volumes (Boe/d)	104,000 to 109,000 (47% liquids)
Capital expenditures	$700 to $750 million (~50% to growth) ($650 to $700 million prior guidance)
Abandonment and reclamation expenditures	$55 million
Free cash flow (1)	$375 million ($630 million prior guidance)

The Company's midpoint 2023 sustaining and maintenance capital program and regular monthly dividend would remain fully funded down to an average WTI price of about US$55/Bbl in 2023. The Company's total midpoint 2023 capital program and regular monthly dividend would remain fully funded down to an average WTI price of about US$71/Bbl in 2023. (2) Paramount remains committed to prudently managing its capital resources and has the flexibility to adjust its capital expenditure plans depending on commodity prices, inflationary cost pressures and other factors.

Preliminary 2024 Guidance (3)

Annual average sales volumes (Boe/d)	110,000 to 120,000 (48% liquids)
Capital expenditures	$700 to $800 million (~50% to growth)
Free cash flow (4)	$465 million ($620 million prior guidance)

Five-Year Outlook (5)

2027 annual average sales volumes (Boe/d)	135,000 to 145,000
Annual capital expenditures	$700 to $800 million
Midpoint cumulative free cash flow (6)	$3.1 billion ($3.9 billion previously)

(1) Free cash flow is a capital management measure used by Paramount. Refer to "Advisories - Specified Financial Measures" for more information on this measure. The stated free cash flow forecast is based on the following assumptions for 2023: (i) the midpoint of stated capital expenditures and sales volumes, (ii) $55 million in abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $55.20/Boe (US$80.00/Bbl WTI, US$3.50/MMBtu NYMEX, $3.08/GJ AECO), (v) a $US/$CAD exchange rate of $0.755, (vi) royalties of $8.30/Boe, (vii) operating costs of $11.40/Boe and (vii) transportation and processing costs of $3.55/Boe.

(2) Assuming no changes to the other forecast assumptions for 2023.

(3) All 2024 guidance is based on preliminary planning and current market conditions and is subject to change.

(4) The stated free cash flow estimate is based on the following assumptions for 2024: (i) the midpoint of stated capital expenditures and sales volumes, (ii) $40 million in abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $53.50/Boe (US$75.00/Bbl WTI, US$3.50/MMBtu NYMEX, $3.08/GJ AECO), (v) a $US/$CAD exchange rate of $0.755, (vi) royalties of $8.30/Boe, (vii) operating costs of $10.55/Boe and (vii) transportation and processing costs of $3.60/Boe.

(5) The five-year outlook is based on preliminary planning and current market conditions and is subject to change. The five-year outlook is for the period from 2023 through to the end of 2027.

(6) The stated cumulative free cash flow estimate is based on the following assumptions: (i) the stated annual capital expenditures and management assumptions as to annual sales volume growth; (ii) $55 million in abandonment and reclamation costs in 2023 and approximately $40 million annually thereafter, (iii) approximately $7 million in annual geological and geophysical expenses, (iv) 2023 realized pricing of $55.20/Boe (US$80.00/Bbl WTI, US$3.50/MMBtu NYMEX, $3.08/GJ AECO) and thereafter commodity prices of US$75.00/Bbl WTI, US$3.50/MMBtu NYMEX and $3.08/GJ AECO, (v) a $US/$CAD exchange rate of $0.755 and (vi) internal management estimates of future royalties, operating costs, transportation and processing costs and, beginning in 2027, cash taxes.

MARCH DIVIDEND

Paramount's Board of Directors has declared a cash dividend of $0.125 per Common Share that will be payable on March 31, 2023 to shareholders of record on March 15, 2023. The dividend will be designated as an "eligible dividend" for Canadian income tax purposes.

HEDGING

The Company's current commodity and foreign currency exchange contracts are summarized below:

	Q1 2023	Q2 2023	Q3 2023	Q4 2023	2024	Average Price (1)
Oil						
Condensate – Basis (Physical Sale) (Bbl/d)	5,244	–	–	–	–	WTI + US$0.50/Bbl
Sweet Crude Oil – Basis (Physical Sale) (Bbl/d)	3,146	3,112	3,078	3,078	–	WTI – US$3.73/Bbl
Natural Gas						
NYMEX Collars (MMBtu/d)	20,000	–	–	–	–	US$7.50/MMBtu (Floor) US$12.13/MMBtu (Ceiling)
AECO Collars (GJ/d)	20,000	–	–	–	–	CAD$7.25/GJ (Floor) CAD$9.60/GJ (Ceiling)
Chicago Index Swap (Sale) (MMBtu/d) (2)	5,000	–	–	–	–	Daily – US$0.09/MMBtu
AECO – Basis (Physical Sale) (MMBtu/d)	–	20,000	20,000	6,739	–	NYMEX – US$0.94/MMBtu
Dawn – Basis (Physical Sale) (MMBtu/d)	–	10,000	10,000	3,370	–	NYMEX – US$0.19/MMBtu
Foreign Currency Exchange						
Forward Sales / Swaps (US$MM/Month)	$60	–	–	–	–	1.3105 CAD$ / US$
Swaps (US$MM/Month)	–	$60	–	–	–	1.3293 CAD$ / US$
Swaps (US$MM/Month)	–	–	$40	$40	–	1.3427 CAD$ / US$
Swaps (US$MM/Month)	–	–	–	–	$20	1.3425 CAD$ / US$

(1) Average price is calculated on a volume weighted average basis.
(2) "Chicago Index" refers to Chicago Index pricing. These contracts convert price exposure of Chicago monthly index to daily index.

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, 2022 (the "Consolidated Financial Statements") and the accompanying management's discussion and analysis (the "MD&A"); and (ii) 2022 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 on Wednesday, May 3, 2023 at 10:30 a.m. (Calgary time) in the McMurray Room of the Calgary Petroleum Club, located at 319 – 5th Avenue S.W., Calgary Alberta.

FINANCIAL AND OPERATING RESULTS [1]

($ millions, except as noted)	Three months ended December 31		Year ended December 31	
	2022	2021	2022	2021
Net income	259.9	101.0	680.6	236.9
per share – basic ($/share)	1.83	0.75	4.83	1.77
per share – diluted ($/share)	1.76	0.70	4.63	1.67
Cash from operating activities	306.9	191.8	1,049.6	482.1
per share – basic ($/share)	2.17	1.42	7.45	3.61
per share – diluted ($/share)	2.08	1.33	7.14	3.39
Adjusted funds flow	340.7	174.6	1,171.0	499.8
per share – basic ($/share)	2.40	1.29	8.32	3.74
per share – diluted ($/share)	2.31	1.21	7.97	3.51
Free cash flow	162.0	99.0	471.1	191.8
per share – basic ($/share)	1.14	0.73	3.35	1.44
per share – diluted ($/share)	1.10	0.69	3.20	1.36
Total assets			4,337.3	3,885.1
Investments in securities			557.1	372.1
Long-term debt			159.4	386.3
Net debt			161.2	456.7
Common shares outstanding *(millions)* [2]			142.0	139.2
Sales volumes [3]				
Natural gas (MMcf/d)	321.9	284.8	294.7	275.2
Condensate and oil (Bbl/d)	37,580	32,342	33,908	30,989
Other NGLs (Bbl/d)	6,143	5,462	5,650	5,147
Total (Boe/d)	97,370	85,265	88,672	82,001
% liquids	45%	44%	45%	44%
Grande Prairie Region (Boe/d)	64,434	56,035	58,519	51,869
Kaybob Region (Boe/d)	24,477	21,725	22,730	22,588
Central Alberta & Other Region (Boe/d)	8,459	7,505	7,423	7,544
Total (Boe/d)	97,370	85,265	88,672	82,001

Netback	2022 Q4	$/Boe [4]	2021 Q4	$/Boe [4]	2022 Year	$/Boe [4]	2021 Year	$/Boe [4]
Natural gas revenue	194.2	6.56	124.7	4.76	671.1	6.24	373.3	3.72
Condensate and oil revenue	375.1	108.50	281.1	94.46	1,448.9	117.07	926.5	81.91
Other NGLs revenue	27.3	48.25	27.4	54.61	114.2	55.37	78.6	41.84
Royalty and other revenue	1.1	—	1.3	—	18.2	—	5.2	—
Petroleum and natural gas sales	597.7	66.72	434.5	55.40	2,252.4	69.60	1,383.6	46.23
Royalties	(84.4)	(9.43)	(52.5)	(6.69)	(335.3)	(10.36)	(127.0)	(4.24)
Operating expense	(119.2)	(13.31)	(91.0)	(11.61)	(407.1)	(12.58)	(340.4)	(11.37)
Transportation and NGLs processing	(27.2)	(3.03)	(26.1)	(3.33)	(123.7)	(3.82)	(114.5)	(3.83)
Sales of commodities purchased [5]	102.7	11.47	22.1	2.82	272.0	8.41	75.5	2.52
Commodities purchased [5]	(100.4)	(11.21)	(22.3)	(2.85)	(267.0)	(8.25)	(76.1)	(2.54)
Netback	369.2	41.21	264.7	33.74	1,391.3	43.00	801.1	26.77
Risk management contract settlements	(23.0)	(2.57)	(72.4)	(9.23)	(179.0)	(5.53)	(218.3)	(7.29)
Netback including risk management contract settlements	364.2	38.64	192.3	24.51	1,212.3	37.47	582.8	19.48

Capital expenditures	2022 Q4	2021 Q4	2022 Year	2021 Year
Grande Prairie Region	135.8	57.7	453.3	228.6
Kaybob Region	11.4	3.8	131.2	14.5
Central Alberta & Other Region	1.0	2.6	2.1	25.2
Fox Drilling and Cavalier Energy	12.1	1.0	27.7	5.0
Corporate	9.3	0.6	40.7	1.3
Total	169.6	65.7	655.0	274.6
Asset retirement obligations settled	7.0	7.0	36.1	25.4

(1) Adjusted funds flow, free cash flow and net debt are capital management measures used by Paramount. Netback and netback including risk management contract settlements are non-GAAP financial measures. Netback and Netback including risk management contract settlements presented on a $/Boe or $/Mcf basis are non-GAAP ratios. Each measure, other than net income, that is presented on a per share, $/Mcf or $/Boe basis is a supplementary financial measure. Refer to the "Specified Financial Measures" section for more information on these measures. Prior period free cash flow has been reclassified to conform with the current year's presentation.
(2) Common shares are presented net of shares held in trust under the Company's restricted share unit plan: 2022: 0.8 million, 2021: 1.5 million
(3) Refer to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.
(4) Natural gas revenue presented as $/Mcf.
(5) Sales of commodities purchased and commodities purchased are treated as corporate items and not allocated to individual regions or properties.

REVIEW OF OPERATIONS

In 2022, the Company:

- Achieved record annual sales volumes, cash from operating activities, adjusted funds flow and free cash flow.
- On a year-over-year basis, increased average annual sales volumes 8% to 88,672 Boe/d (45% liquids) and fourth quarter sales volumes 14% to 97,370 Boe/d (45% liquids).
- Delivered average monthly sales volumes in excess of 30,000 Boe/d at Wapiti for the first time in September, one quarter ahead of plan.
- Tripled the size of its Willesden Green Duvernay core area to approximately 240,000 net acres and over 700 internally estimated drilling locations. (1)
- Drilled 62 (56.3 net) wells and brought 57 (52.1 net) wells on production.
- Continued to focus on advancements in well design, planning and execution to maximize the full-cycle economics of its asset base.
- Realized aggregate proceeds of $121 million on the disposition of non-core resource roads and investments in securities that were applied to reduce bank debt.
- Achieved its net debt target of $300 million in October. Net debt was further reduced to $161 million at December 31, 2022, representing a $296 million year-over-year reduction.
- Distributed $160 million in regular monthly dividends to shareholders.
- Initiated the replacement of 26 pneumatic chemical pumps, which is expected to reduce vented methane emissions by approximately 2,100 tonnes/CO_2e per year.
- Abandoned 74 wells, including 42 wells under the Company's area-based closure program at Zama.

In January 2023, Paramount closed the sale of its Kaybob Smoky and Kaybob South Duvernay properties and certain other minor interests in the Kaybob Region for cash proceeds of approximately $370 million. Following the disposition, the Company paid a special cash dividend of $1.00 per Common Share and repaid all remaining drawings on its $1.0 billion credit facility.

Sales volumes averaged 88,672 Boe/d (45% liquids) in 2022 and 97,370 Boe/d (45% liquids) in the fourth quarter of 2022. In 2022, Grande Prairie Region sales volumes averaged 58,519 Boe/d (52% liquids), representing 66% of total Company sales volumes.

2022 capital expenditures, which were largely directed to the Grande Prairie Montney and Kaybob Duvernay developments, totaled $655 million. Capital expenditures in 2023 are expected to range between $700 million and $750 million, resulting in expected average 2023 sales volumes of between 100,000 Boe/d and 105,000 Boe/d (46% liquids).

Capital expenditures in 2023 will be directed to Paramount's established Montney developments at Karr and Wapiti in the Grande Prairie Region and its emerging Duvernay developments at Kaybob North in the Kaybob Region and Willesden Green in the Central Alberta and Other Region. Activities in the Grande

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

Prairie Region will include the drilling and bringing on production of new wells as well as further debottlenecking of infrastructure to grow Grande Prairie Region sales volumes to between 77,000 and 82,000 Boe/d in the second half of 2023. Development activities will also include the drilling and bringing on production of new wells at Kaybob North Duvernay as well as the expansion of infrastructure at Willesden Green.

GRANDE PRAIRIE REGION

Development activities in the Grande Prairie Region are focused on the Karr and Wapiti properties, located south of the city of Grande Prairie, Alberta, in the over-pressured liquids-rich Deep Basin Montney trend. At December 31, 2022, Paramount held approximately 101,000 net acres of Montney rights at Karr and Wapiti.

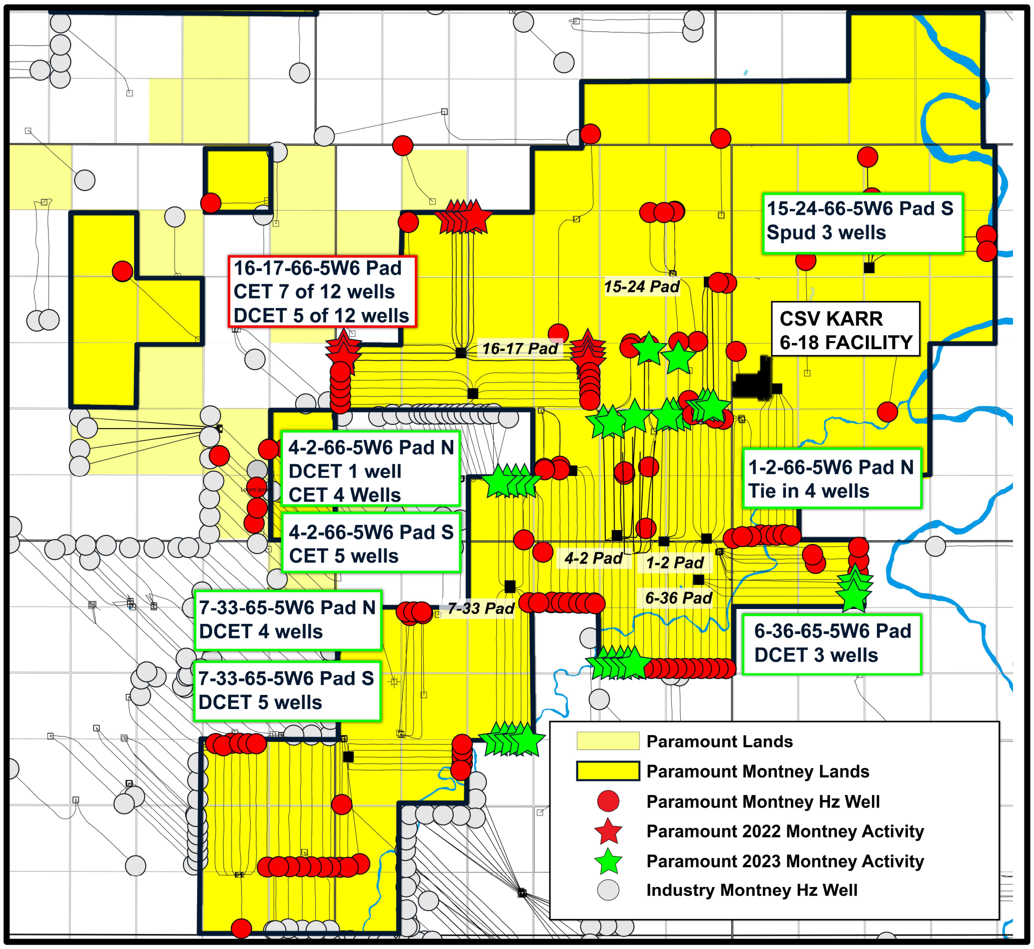
Grande Prairie Region sales volumes averaged 58,519 Boe/d (52% liquids) in 2022, with approximately 60% being produced from the Karr development and 40% from the Wapiti development. Capital expenditures in the Grande Prairie Region totaled $453.3 million in 2022, which were focused mainly on drilling and completion operations.

Grande Prairie Region sales volumes and netbacks are summarized below:

	Three months ended December 31				Year ended December 31			
	2022		2021		**2022**		2021	
Sales volumes								
Natural gas (MMcf/d)	**189.9**		158.9		**168.2**		141.0	
Condensate and oil (Bbl/d)	**29,146**		26,278		**27,099**		25,258	
Other NGLs (Bbl/d)	**3,631**		3,276		**3,394**		3,103	
Total (Boe/d)	**64,434**		56,035		**58,519**		51,869	
% liquids	***51%***		*53%*		***52%***		*55%*	
Netback (1)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Natural gas revenue (2)	**125.4**	***7.18***	71.5	*4.89*	**402.5**	***6.56***	196.5	*3.82*
Condensate and oil revenue	**293.9**	***109.60***	230.5	*95.37*	**1,166.6**	***117.95***	761.4	*82.59*
Other NGLs revenue	**17.1**	***51.22***	16.6	*54.97*	**70.6**	***56.94***	48.2	*42.56*
Royalty and other revenue (3)	**–**	**–**	–	–	**12.1**	**–**	–	–
Petroleum and natural gas sales	**436.4**	***73.62***	318.6	*61.81*	**1,651.8**	***77.33***	1,006.1	*53.14*
Royalties	**(66.4)**	***(11.21)***	(39.8)	*(7.74)*	**(261.2)**	***(12.23)***	(87.2)	*(4.61)*
Operating expense	**(69.9)**	***(11.80)***	(54.9)	*(10.64)*	**(247.6)**	***(11.59)***	(205.3)	*(10.84)*
Transportation and NGLs processing	**(22.1)**	***(3.70)***	(19.0)	*(3.68)*	**(93.1)**	***(4.36)***	(82.9)	*(4.37)*
	278.0	***46.91***	204.9	*39.75*	**1,049.9**	***49.15***	630.7	*33.32*

(1) "Netback" is a Non-GAAP financial measure. When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure and Netback is a non-GAAP ratio. Refer to the "Specified Financial Measures" section for more information on these measures.
(2) Per unit natural gas revenue presented as $/Mcf.
(3) Royalty and other revenue in 2022 includes $11.9 million related to proceeds from a business interruption insurance claim.

KARR AREA



Karr sales volumes and netbacks are summarized below:

	Three months ended December 31				Year ended December 31			
	2022		2021		**2022**		2021	
Sales volumes								
Natural gas (MMcf/d)	**111.9**		124.0		**108.3**		109.2	
Condensate and oil (Bbl/d)	**15,308**		18,521		**15,723**		17,858	
Other NGLs (Bbl/d)	**2,247**		2,449		**2,273**		2,330	
Total (Boe/d)	**36,209**		41,629		**36,050**		38,381	
% liquids	***48%***		*50%*		***50%***		*53%*	
Netback (1)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Natural gas revenue (2)	**72.9**	***7.08***	55.2	*4.84*	**254.0**	***6.42***	150.9	*3.78*
Condensate and oil revenue	**155.6**	***110.51***	161.3	*94.67*	**682.8**	***118.98***	536.9	*82.38*
Other NGLs revenue	**10.8**	***52.12***	13.1	*58.20*	**48.1**	***57.91***	37.6	*44.19*
Royalty and other revenue	**–**	**–**	–	–	**0.1**	**–**	–	–
Petroleum and natural gas sales	**239.3**	***71.84***	229.6	*59.96*	**985.0**	***74.86***	725.4	*51.78*
Royalties	**(42.7)**	***(12.83)***	(35.7)	*(9.32)*	**(190.2)**	***(14.46)***	(74.5)	*(5.32)*
Operating expense	**(38.5)**	***(11.55)***	(36.0)	*(9.38)*	**(149.3)**	***(11.35)***	(134.1)	*(9.57)*
Transportation and NGLs processing	**(11.5)**	***(3.43)***	(14.0)	*(3.68)*	**(58.4)**	***(4.43)***	(59.7)	*(4.26)*
	146.6	***44.03***	143.9	*37.58*	**587.1**	***44.62***	457.1	*32.63*

(1) "Netback" is a Non-GAAP financial measure. When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure and Netback is a non-GAAP ratio. Refer to the "Specified Financial Measures" section for more information on these measures.
(2) Per unit natural gas revenue presented as $/Mcf.

Development activities at Karr in 2022 were focused on drilling a total of 18 (18.0 net) operated Montney wells, including the remaining five wells on the 12-well 16-17 pad, nine of ten wells on the 4-2 North and 4-2 South pads and four wells on the 1-2 North pad. The Company brought onstream all 12 (12.0 net) wells on the 16-17 pad in the first and third quarters and also built out incremental gas lift compression and associated infrastructure to support production growth in 2023 and beyond.

Karr sales volumes averaged 36,050 Boe/d (50% liquids) in 2022 compared to 38,381 Boe/d (53% liquids) in 2021. Sales volumes in 2022 at Karr were impacted by: (i) turnarounds at two third-party midstream facilities during the second quarter that resulted in production being shut-in for approximately three weeks, eight days longer than planned, (ii) unplanned facility outages and downtime related to extended workover operations early in the third quarter, and (iii) unexpected infrastructure downtime coupled with the impact of extreme cold weather, both late in the fourth quarter.

The Company continues to focus on maximizing efficiencies in its drilling, completion and tie-in operations in an effort to mitigate inflationary cost pressures. All-in lease construction, drilling, completion, equip and tie-in (collectively "DCET") costs associated with the 2022 program were approximately $7.5 million per well. The Company's go-forward Karr DCET cost assumption is approximately $8.7 million per well. Average gross peak 30-day production per well at the 16-17 pad was 1,498 Boe/d (3.8 MMcf/d of shale gas and 875 Bbl/d of NGLs) with an average CGR of 234 Bbl/MMcf.(1) Paramount has begun trialing longer-reach laterals in the Montney formation to achieve further efficiencies in the development of its land base.

Paramount's 2023 activities at Karr will be focused on drilling and completion activities as well as the completion of infrastructure debottlenecking. The Company plans to drill 15 (15.0 net) Montney wells and bring onstream a total of 22 (22.0 net) new Montney wells in 2023.

All four wells at the 1-2 North pad were brought onstream in early 2023. One well on the 1-2 North Pad was drilled to a total measured depth of 7,060 meters.

Completion operations at the 4-2 South and 4-2 North pads are now complete and Paramount anticipates bringing all ten wells onstream in the second quarter of 2023. The 4-2 North pad includes one well that was drilled to a total measured depth of 7,457 meters with a lateral length of 4,467 meters, making it the longest well drilled in the Company's history.

Drilling operations are scheduled to commence at the five-well 7-33 South pad in the second quarter of 2023 with all wells expected to be completed and brought onstream in the second half of the year.

Paramount also plans to drill, complete, tie-in and bring on production three wells at the 6-36 pad in the second half of the year and drill, complete and tie-in four wells at the 7-33 North pad, with first production anticipated in early 2024. In addition, the Company expects to commence the drilling of two wells at the three-well 15-24 pad before the end of the 2023.

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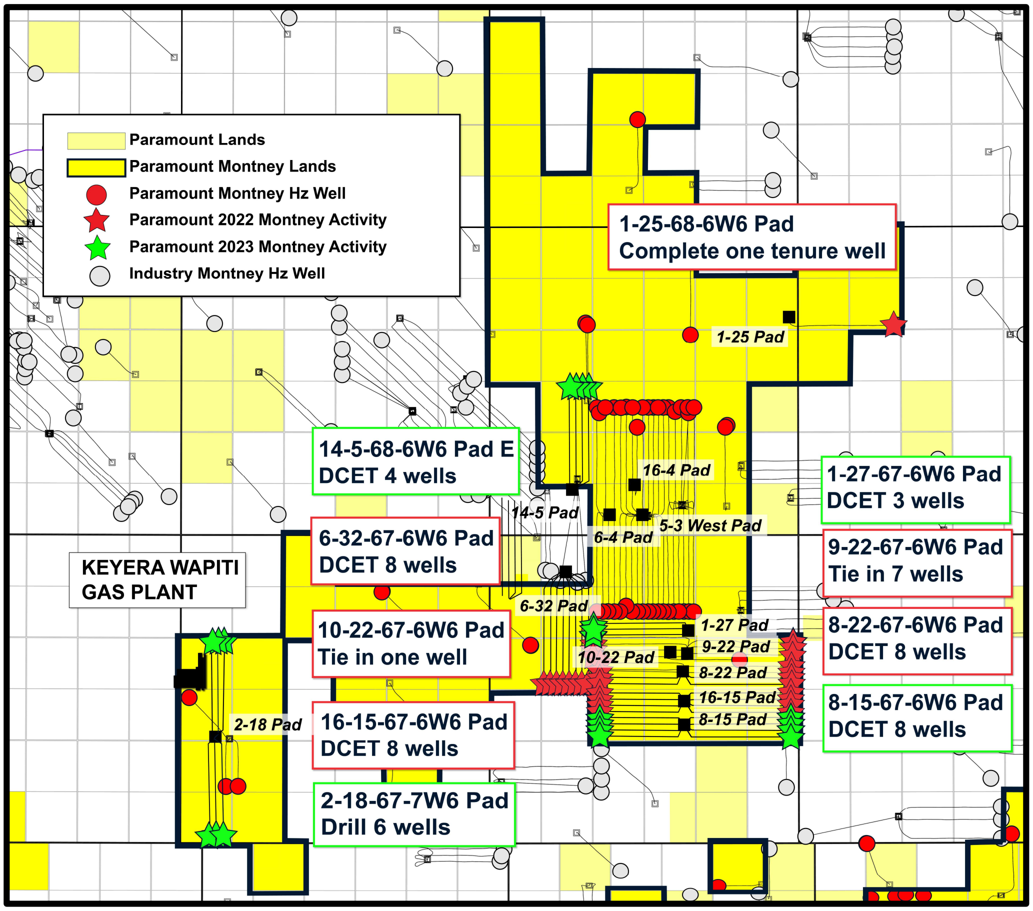
(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 10% and liquids sales volumes were lower by approximately 6% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, 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			
	2022		2021		**2022**		2021	
Sales volumes								
Natural gas (MMcf/d)	**78.0**		34.9		**59.9**		31.8	
Condensate and oil (Bbl/d)	**13,838**		7,757		**11,376**		7,400	
Other NGLs (Bbl/d)	**1,384**		827		**1,121**		773	
Total (Boe/d)	**28,225**		14,406		**22,469**		13,488	
% liquids	***54%***		*60%*		***56%***		*61%*	
Netback (1)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Natural gas revenue (2)	**52.5**	***7.32***	16.3	*5.07*	**148.5**	***6.80***	45.6	*3.92*
Condensate and oil revenue	**138.3**	***108.59***	69.2	*97.03*	**483.8**	***116.51***	224.5	*83.09*
Other NGLs revenue	**6.3**	***49.74***	3.5	*45.43*	**22.5**	***54.95***	10.6	*37.61*
Royalty and other revenue (3)	**–**	***–***	–	*–*	**12.0**	***–***	–	*–*
Petroleum and natural gas sales	**197.1**	***75.90***	89.0	*67.15*	**666.8**	***81.30***	280.7	*57.03*
Royalties	**(23.7)**	***(9.13)***	(4.1)	*(3.18)*	**(71.0)**	***(8.65)***	(12.7)	*(2.58)*
Operating expense	**(31.4)**	***(12.11)***	(18.9)	*(14.26)*	**(98.3)**	***(11.99)***	(71.2)	*(14.46)*
Transportation and NGLs processing	**(10.6)**	***(4.05)***	(5.0)	*(3.69)*	**(34.7)**	***(4.24)***	(23.2)	*(4.73)*
	131.4	***50.61***	61.0	*46.02*	**462.8**	***56.42***	173.6	*35.26*

(1) "Netback" is a Non-GAAP financial measure. When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure and Netback is a non-GAAP ratio. Refer to the "Specified Financial Measures" section for more information on these measures.
(2) Per unit natural gas revenue presented as $/Mcf.
(3) Royalty and other revenue in 2022 includes $11.9 million related to proceeds from a business interruption insurance claim.

The 2022 capital program at Wapiti focused on drilling and completion activities that resulted in the Company achieving targeted average monthly sales volumes of 30,000 Boe/d in September for the first time, one quarter ahead of schedule. This achievement was the result of well outperformance relative to the Wapiti type curve. Development activities in the year included bringing onstream the remaining four wells at the seven-well 9-22 pad in the first quarter and the drilling, completion and tie-in of the eight-well 8-22 pad and the eight-well 6-32 pad by the second quarter and third quarters, respectively. The Company also drilled, completed and tied-in six wells at the eight-well 16-15 pad by the fourth quarter of 2022. In all, 25 (25.0 net) new Montney wells were drilled and 27 (27.0 net) new Montney wells were brought onstream in 2022.

All wells on the 16-15 pad are now on production and have exhibited strong production rates, averaging gross peak 30-day production per well of 1,539 Boe/d (3.6 MMcf/d of shale gas and 940 Bbl/d of NGLs) with an average CGR of 262 Bbl/MMcf. Average gross peak 30-day production per well for Wapiti pads brought on production in 2022 was 1,582 Boe/d (4.2 MMcf/d of shale gas and 889 Bbl/d of NGLs) with an average CGR of 214 Bbl/MMcf.(1)

All-in DCET costs at the 16-15 pad averaged $7.9 million per well, while all-in DCET costs for the last three Wapiti pads averaged $7.6 million per well. The Company's go-forward Wapiti DCET cost assumption is approximately $8.3 million per well.

Sales volumes at Wapiti averaged 22,469 Boe/d (56% liquids) in 2022 compared to 13,488 Boe/d (61% liquids) in 2021. The increase was driven primarily by production from new wells that were brought onstream during the year as well as stronger than expected performance from wells in the southern areas of Paramount’s Wapiti land base. This increase in sales volumes was achieved notwithstanding the impacts of several unplanned outages and curtailments during the year. While liquids volumes at the Company's new southern-most pads have proven to be similar to those exhibited by the Company's earlier Wapiti wells, natural gas rates are proving to be considerably higher.

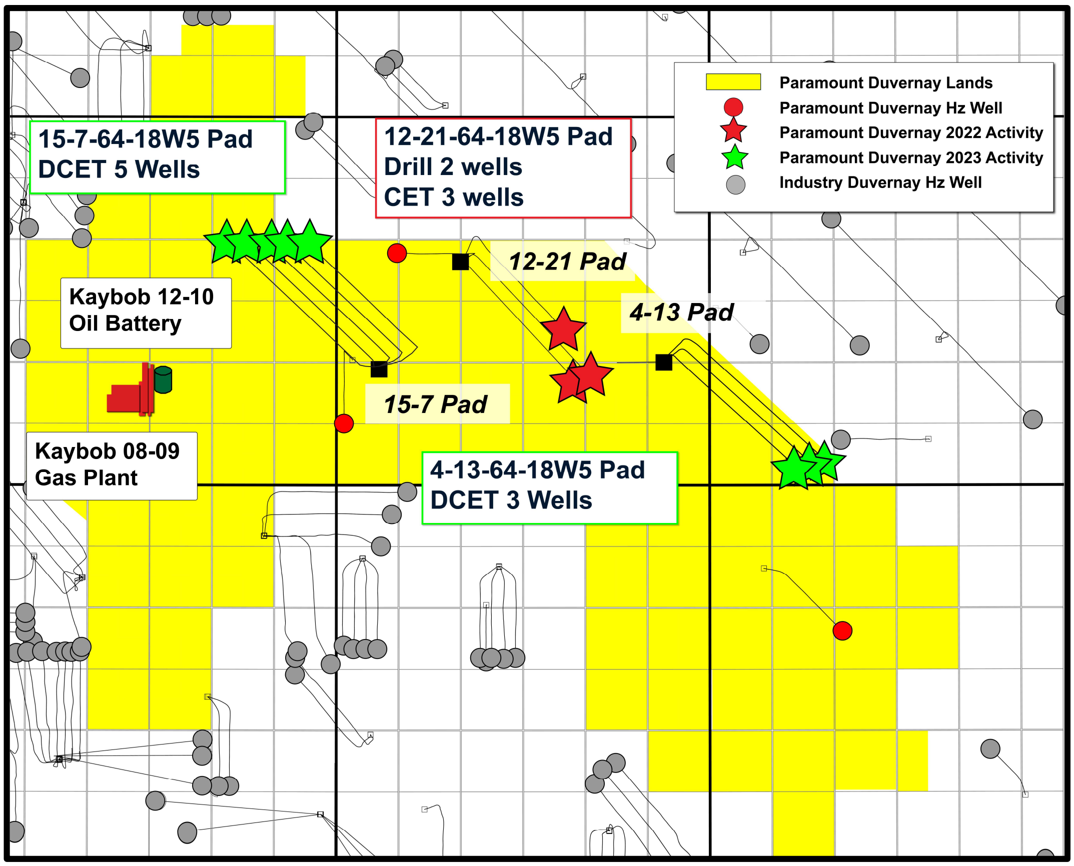
In 2023, the Company plans to drill 20 (20.0 net) wells and bring on production 13 (13.0 net) wells at Wapiti. The three-well 1-27 pad is scheduled to be completed over the first half of the year and brought on production by the third quarter. Drilling operations are scheduled to commence at the eight-well 8-15 pad in the first quarter and Paramount plans to complete and tie-in all eight wells by the second half of the 2023. Drilling and completions operations at the four-well 14-5 East pad are scheduled for the second half of 2023, with first production anticipated in early 2024. The Company now plans to drill all six wells at the 2-18 pad by the end of the 2023.

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 10% and liquids sales volumes were lower by approximately 2% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See "Oil and Gas Measures and Definitions" in the Advisories section.

KAYBOB REGION

The Kaybob Region, located in west-central Alberta, includes the Kaybob North Duvernay development, the Kaybob North Montney oil development and other low-decline, legacy shale gas and conventional natural gas producing properties. The Company holds 122,000 net acres of Duvernay rights and approximately 256,000 net acres of Montney rights and owns and operates extensive processing and gathering infrastructure in the Region.

The map below highlights the Company's Duvernay land position and planned activities at Kaybob North.



Kaybob Region sales volumes averaged 22,730 Boe/d (31% liquids) in 2022 compared to 22,588 Boe/d (28% liquids) in 2021. New well production offset natural declines in the year.

Capital expenditures in the Kaybob Region totaled $131.2 million in 2022. Development activities included bringing onstream three (3.0 net) Duvernay wells at Kaybob North, four (4.0 net) Duvernay wells at Smoky, four (2.5 net) Montney gas wells, two (2.0 net) Gething oil wells and one (1.0 net) Montney oil well.

In 2022, Paramount agreed to sell its Kaybob Smoky Duvernay and Kaybob South Duvernay assets for cash proceeds of approximately $370 million. Sales volumes from these assets were approximately 4,700 Boe/d (13.8 MMcf/d of shale gas and 2,400 Bbl/d of NGLs) in the fourth quarter of 2022. The assets included approximately 67,000 net acres of land, with 8.9 MMBoe of PDP, 36.1 MMBoe of TP and 60.3 MMBoe of P+P reserves based on the Company's December 31, 2022 reserves report. [(1)] The transaction

(1) See "Reserves Data" in the Advisories section.

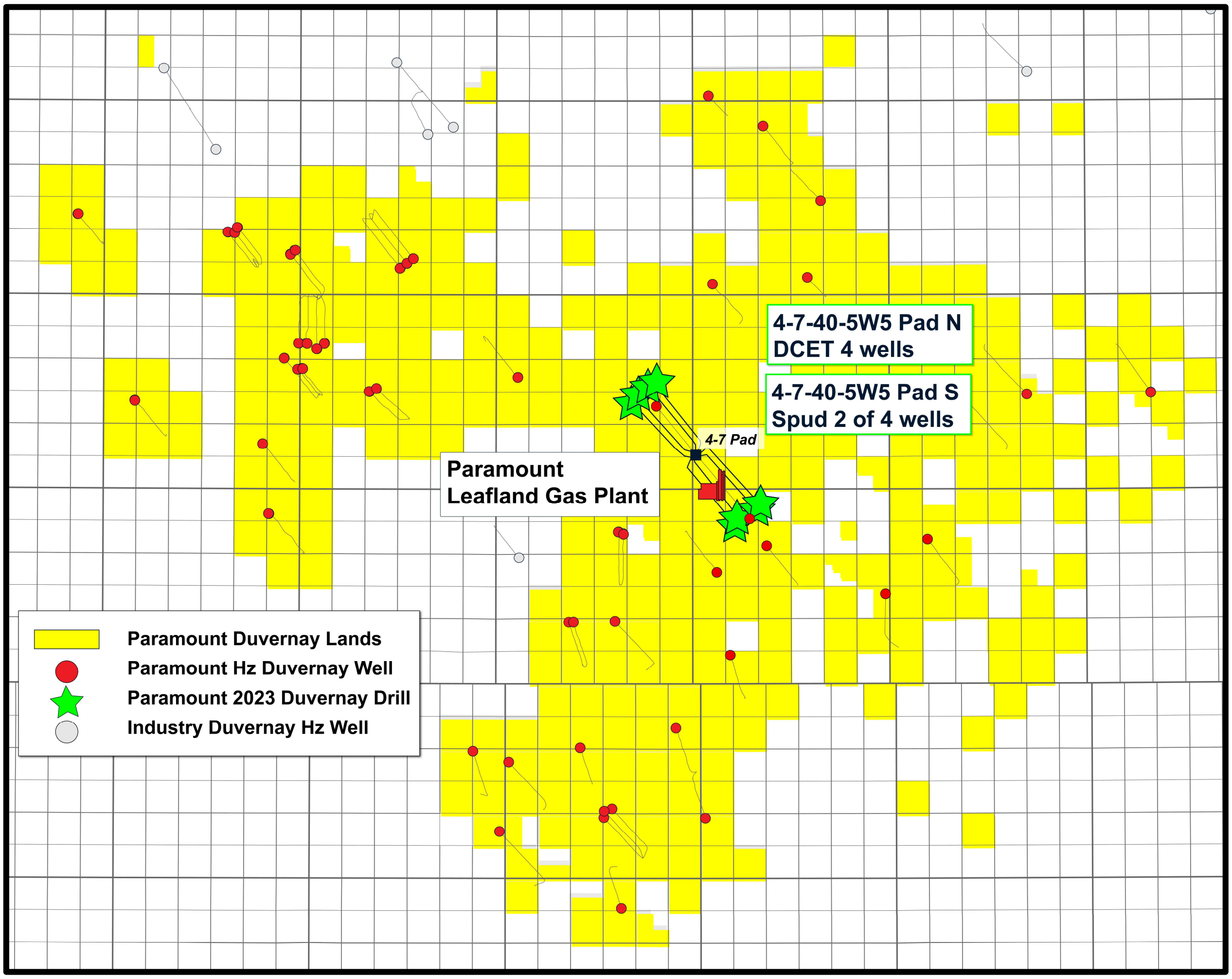
closed in January 2023. Also in 2022, Paramount sold approximately 60 kilometers of non-core resource roads in the Bigstone area of the Kaybob Region for cash proceeds of approximately $64 million.

In 2023, Paramount plans to advance the development of its Kaybob North Duvernay asset by drilling and bringing onstream a total of eight (8.0 net) wells. Drilling operations at the three-well 4-13 South pad commenced in early 2023 and the Company expects to complete and tie-in all three wells by the third quarter. The drilling of the five-well 15-7 pad is scheduled to commence in the second quarter and Paramount anticipates all five wells to come onstream late in the year.

Additional activities planned for 2023 include the optimization of existing infrastructure and the drilling, completion and tie-in of two (1.4 net) Montney gas wells.

CENTRAL ALBERTA AND OTHER REGION

The Central Alberta and Other Region includes approximately 240,000 net acres of Duvernay rights at Willesden Green in west-central Alberta as well as 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 7,423 Boe/d (26% liquids) in 2022 compared to 7,544 Boe/d (18% liquids) in 2021. Sales volumes were largely flat with production additions from the newly acquired Willesden Green properties offsetting lower production due to the July 2021 sale of the Birch field.

In 2022, Paramount significantly expanded its Duvernay holdings in the Willesden Green core area through two acquisitions at a total cost of approximately $98 million. Combined, the transactions more than tripled the size of the asset, adding approximately 180,000 net acres of Duvernay rights and approximately 400 undeveloped internally estimated drilling locations. (1)

Paramount has initiated the first two phases of its Willesden Green development in 2023. Planned activities in the year include the drilling and completion of four (4.0 net) Duvernay wells, an expansion of the Company's majority-owned Leafland natural gas processing plant ("Leafland Plant") and front-end

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

engineering and design of a second natural gas processing plant which is scheduled to be in-service by 2025.

The drilling of a four-well pad is planned to commence in the second quarter of 2023 with completion operations to follow over the third and fourth quarters. Paramount anticipates all four wells to come onstream in early 2024. The Company also anticipates commencing the drilling of two wells at a second four-well pad by the end of the year. Paramount, through its Fox Drilling subsidiary, is constructing a fifth super-spec walking rig that will be deployed in the Company's 2023 Willesden Green drilling program.

The expansion of liquids processing capacity at the Leafland Plant commenced in 2022 with front-end engineering and design and the pre-ordering of long-lead items. Once completed, the plant will be capable of processing approximately 22 MMcf/d of raw inlet gas and 6,000 Bbl/d of condensate. Startup of the newly expanded plant is anticipated to occur in the first quarter of 2024.

Planning is underway on the second phase of development at Willesden Green, including the advancement of a second to-be-newly constructed processing facility. The Company continues to anticipate growing production over the next five years in three phases, which will initially double mid-point Willesden Green production from 3,750 Boe/d (47% liquids) in 2023 to 7,500 Boe/d (59% liquids) in 2024. Production is then expected to average between 15,000 Boe/d and 20,000 Boe/d (59% liquids) for each of 2025 and 2026. In the third phase of development, production is expected to grow to approximately 30,000 Boe/d (58% liquids) by 2027.

With the 2022 acquisitions, Paramount controls approximately 240,000 net acres of contiguous land at Willesden Green with over 700 internally estimated Duvernay drilling locations, which supports a targeted full field development plateau production of over 50,000 Boe/d that can be sustained for over 20 years.[1]

Recently, the Company successfully completed a methane emissions reduction pilot project in the Willesden Green field which involved the replacement of 26 pneumatic chemical pumps with solar powered pumps. The pilot project is projected to reduce vented emissions by approximately 2,100 tonnes/CO_2e per year and is expected to generate carbon tax credits for future use or sale. The Company is currently evaluating a larger-scale project to replace additional pneumatic chemical pumps across its portfolio.

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

RESERVES AND FINDING AND DEVELOPMENT COSTS [1]

Paramount delivered substantial reserves additions in 2022.

- PDP reserves volumes increased 28% to 160 MMBoe.
- TP reserves volumes increased 31% to 445 MMBoe.
- P+P reserves volumes increased 15% to 759 MMBoe.
- In the Grande Prairie Region, where the majority of 2022 development activity occurred, PDP reserves were up 33%, TP reserves were up 35% and P+P reserves were up 10%.
- 2022 F&D costs were $9.58/Boe for PDP reserves (4.5x recycle ratio), $14.11/Boe for TP reserves (3.0x recycle ratio) and $14.87/Boe for P+P reserves (2.9x recycle ratio). [2]
- Three-year average F&D costs were $8.13/Boe for PDP reserves (3.4x recycle ratio), $7.72/Boe for TP reserves (3.5x recycle ratio) and $4.24/Boe for P+P reserves (6.5x recycle ratio). [2]

Total Company gross reserves at December 31, 2022 and 2021 are as follows:

	Proved [1]			Proved plus Probable [1]		
	2022	2021	*% Change*	**2022**	2021	*% Change*
Natural gas (Bcf)	**1,361.4**	1,034.0	*32*	**2,279.9**	2,009.9	*13*
NGLs (MBbl)	**213,851**	146,264	*46*	**372,985**	296,918	*26*
Crude oil (MBbl)	**3,901**	20,881	*(81)*	**5,803**	30,561	*(81)*
Total (MBoe)	**444,644**	339,476	*31*	**758,769**	662,469	*15*
Before Tax Future Net Revenue NPV$_{10}$ ($ millions)	**$5,798**	$3,573	*62*	**$9,085**	$6,235	*46*

(1) Certain reserves were re-classified from Tight Oil to NGLs in 2022.

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, 2022 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	**160,330**	2,545	2,509	**213,952**	3,905	3,151
Undeveloped	**284,314**	6,528	3,288	**544,817**	13,842	5,934
Total	**444,644**	**9,073**	**5,798**	**758,769**	**17,747**	**9,085**

(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.

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(1) Readers are referred to the advisories concerning "Reserves Data". Reserves evaluated by McDaniel and Associates Consultants Ltd. ("McDaniel") as of December 31, 2022 and December 31, 2021 in accordance with National Instrument 51-101 definitions, standards and procedures. Reserves are gross reserves. Net present values of future net revenue do not represent fair market value. Readers should refer to the Company's annual information forms for the years ended December 31, 2022 and December 31, 2021, which are available on SEDAR at www.sedar.com or on Paramount's website at www.paramountres.com, for a complete description of the reserves evaluations prepared by McDaniel for 2022 and 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.

(2) 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 and on the related non-GAAP financial measure of F&D capital.

Reserves Reconciliation

The reserves reconciliation highlights Paramount's strong replacement of production volumes. Excluding acquisitions and dispositions, additions to TP liquids reserves represented 424% of liquids production and additions to P+P liquids reserves represented 419% of liquids production. Additions to TP natural gas reserves represented 385% of natural gas production and additions to P+P natural gas reserves represented 324% of natural gas production.

The following table provides a summary reconciliation of Paramount's gross reserves for the year ended December 31, 2022. 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, 2022, 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)(2)			Proved plus Probable (1)(2)		
	Natural Gas	Liquids	Total	Natural Gas	Liquids	Total
	(Bcf)	(MBbl)	(MBoe)	(Bcf)	(MBbl)	(MBoe)
December 31, 2021	**1,034.0**	**167,145**	**339,476**	**2,009.9**	**327,479**	**662,469**
Extensions / improved recovery	382.4	63,415	**127,154**	340.6	70,386	**127,161**
Technical revisions	(18.9)	(4,729)	**(7,882)**	(55.8)	(13,398)	**(22,686)**
Economic factors	50.1	2,404	**10,755**	63.7	3,418	**14,039**
Acquisitions	21.5	3,919	**7,502**	29.1	5,306	**10,163**
Dispositions	(0.2)	(2)	**(40)**	(0.3)	(3)	**(55)**
Production	(107.5)	(14,400)	**(32,321)**	(107.5)	(14,400)	**(32,321)**
December 31, 2022	**1,361.4**	**217,752**	**444,644**	**2,279.9**	**378,788**	**758,769**

(1) Columns and rows may not add due to rounding.
(2) McDaniel did not evaluate any of the properties of Cavalier Energy in preparing the McDaniel Report and, accordingly, no reserves have been attributed to such properties.

Significant factors leading to the increase in 2022 total proved and probable reserves include:

- Extensions / improved recovery: Positive extensions were related to: (i) the acceleration of development plans in the Grande Prairie Region to a higher combined production plateau, (ii) the advancement of the Willesden Green Duvernay development, including the determination in November 2022 to proceed with the construction of new processing infrastructure to accommodate a material increase in the scope of development, and (iii) the further advancement of the Kaybob North Duvernay development, including increased well density.
- Technical revisions: Negative technical revisions were attributable to higher operating costs and shrinkage, as well as capital plan changes and well performance. These were partially offset by positive technical revisions related to performance in Wapiti.
- Economic factors: Increases were related to overall higher commodity price forecasts.
- Acquisitions: Were mostly attributable to producing assets in the Willesden Green Duvernay.

Finding and Development Costs and Recycle Ratios [1]

The following table sets out the Company's F&D costs and recycle ratios for the year ended December 31, 2022 and for the three years ended December 31, 2022.

	2022				Three-Year Average [5]			
	F&D Capital [2]	Reserve Additions [3]	F&D	Recycle Ratio [4]	F&D Capital [2]	Reserve Additions [3]	F&D	Recycle Ratio [4]
	($ millions)	(MMBoe)	($/Boe)	*(x)*	($ millions)	(MMBoe)	($/Boe)	*(x)*
TOTAL COMPANY								
Proved Developed Producing	577	60	**9.58**	4.5x	1,107	136	**8.13**	3.4x
Total Proved	1,835	130	**14.11**	3.0x	1,582	205	**7.72**	3.5x
Proved plus Probable	1,762	119	**14.87**	2.9x	961	227	**4.24**	6.5x
GRANDE PRAIRIE REGION								
Proved Developed Producing	433	45	**9.61**	5.1x	833	99	**8.44**	4.1x
Proved	901	91	**9.95**	4.9x	409	110	**3.73**	9.4x
Proved plus Probable	750	63	**11.82**	4.2x	(128)	107	**na**	na

(1) 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.
(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 in reserves from the prior year from extensions/improved recovery, technical revisions and economic factors.
(4) Recycle ratio is calculated by dividing netback, a non-GAAP measure, per Boe by the applicable F&D cost.
(5) The three-year average F&D costs were calculated by dividing total F&D capital over the period by the aggregate reserves additions in the period. The associated recycle ratios were calculated by dividing the weighted average netback, a non-GAAP measure, per Boe over the period by the three-year average F&D costs.

F&D capital increased in 2022 mainly as a result of higher forecast future well costs as well as increases related to acceleration of development in the Willesden Green core area, including the planned expansion of gathering and processing infrastructure.

LAND

Paramount's land position is summarized below: [1]

	December 31, 2022		December 31, 2021	
(thousands of acres)	**Gross** [2]	**Net** [3]	Gross [2]	Net [3]
Acreage assigned reserves	**792**	**645**	653	514
Acreage not assigned reserves	**1,983**	**1,130**	1,995	1,126
Total	**2,775**	**1,775**	2,648	1,640

(1) Excludes Cavalier Energy lands.
(2) 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.
(3) Net acres means gross acres multiplied by Paramount's working interest therein.

In addition to the land position above, Paramount, through its wholly-owned subsidiary Cavalier Energy, holds 276,000 net acres with Clearwater and Bluesky cold flow heavy oil potential out of a total of approximately 1.357 gross (1.312 million net) acres of land prospective for cold flow heavy oil and in-situ thermal recovery.

PRODUCT TYPE INFORMATION

This document 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. 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		Kaybob Region		Central Alberta and Other Region	
	2022	2021	2022	2021	2022	2021	2022	2021
Shale gas (MMcf/d)	232.9	207.9	166.9	138.8	38.5	38.6	27.5	30.5
Conventional natural gas (MMcf/d)	61.8	67.3	1.3	2.2	55.0	58.6	5.5	6.5
Natural gas (MMcf/d)	294.7	275.2	168.2	141.0	93.5	97.2	33.0	37.0
Condensate (Bbl/d)	31,228	28,328	27,095	25,253	3,192	2,295	941	781
Other NGLs (Bbl/d)	5,650	5,147	3,394	3,103	1,620	1,612	636	432
NGLs (Bbl/d)	36,878	33,475	30,489	28,356	4,812	3,907	1,577	1,213
Tight oil (Bbl/d)	480	487	–	–	261	355	219	131
Light and medium crude oil (Bbl/d)	2,200	2,174	4	5	2,066	2,129	130	40
Crude oil (Bbl/d)	2,680	2,661	4	5	2,327	2,484	349	171
Total (Boe/d)	88,672	82,001	58,519	51,869	22,730	22,588	7,423	7,544

	Annual			
	Karr		Wapiti	
	2022	2021	2022	2021
Shale gas (MMcf/d)	107.8	107.9	59.1	30.9
Conventional natural gas (MMcf/d)	0.5	1.3	0.8	0.9
Natural gas (MMcf/d)	108.3	109.2	59.9	31.8
NGLs (Bbl/d)	17,996	20,188	12,493	8,168
Light and Medium crude oil (Bbl/d)	–	–	4	5
Total (Boe/d)	36,050	38,381	22,469	13,488

	Q4							
	Total		Grande Prairie Region		Kaybob Region		Central Alberta and Other Region	
	2022	2021	2022	2021	2022	2021	2022	2021
Shale gas (MMcf/d)	260.0	220.4	188.4	156.5	41.9	35.6	29.7	28.2
Conventional natural gas (MMcf/d)	61.9	64.4	1.5	2.4	55.0	56.8	5.4	5.3
Natural gas (MMcf/d)	321.9	284.8	189.9	158.9	96.9	92.4	35.1	33.5
Condensate (Bbl/d)	34,616	29,797	29,146	26,272	4,354	2,184	1,116	1,341
Other NGLs (Bbl/d)	6,143	5,462	3,631	3,276	1,671	1,788	841	398
NGLs (Bbl/d)	40,759	35,259	32,777	29,548	6,025	3,972	1,957	1,739
Tight oil (Bbl/d)	629	497	–	–	262	355	367	142
Light and medium crude oil (Bbl/d)	2,335	2,048	–	6	2,045	2,000	290	42
Crude oil (Bbl/d)	2,964	2,545	–	6	2,307	2,355	657	184
Total (Boe/d)	97,370	85,265	64,434	56,035	24,477	21,725	8,459	7,505

	Q4			
	Karr		Wapiti	
	2022	2021	2022	2021
Shale gas (MMcf/d)	111.5	122.5	76.9	34.0
Conventional natural gas (MMcf/d)	0.4	1.5	1.1	0.9
Natural gas (MMcf/d)	111.9	124.0	78.0	34.9
NGLs (Bbl/d)	17,555	20,970	15,222	8,578
Light and Medium crude oil (Bbl/d)	-	-	-	6
Total (Boe/d)	36,209	41,629	28,225	14,406

The Company forecasts that 2023 annual sales volumes will average between 100,000 Boe/d and 105,000 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 2023 sales volumes are expected to average between 96,000 Boe/d and 101,000 Boe/d (55% shale gas and conventional natural gas combined, 38% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). Second half 2023 sales volumes are expected to average between 104,000 Boe/d and 109,000 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). The Company's preliminary 2024 guidance provides for annual sales volumes that will average between 110,000 Boe/d and 120,000 Boe/d (52% shale gas and conventional natural gas combined, 41% light and medium crude oil, tight oil and condensate combined and 7% 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) plus sales of commodities purchased less royalties, operating expense, transportation and NGLs processing expense and commodities purchased. Sales of commodities purchased and commodities purchased are treated as corporate items and not allocated to individual regions or properties. Netback is used by investors and management to compare the performance of the Company's producing assets between periods.

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

Refer to the table under the heading "Financial and Operating Results" in the press release included in this document for the calculation of netback and netback including risk management contract settlements for the years ended December 31, 2022 and 2021 and for the three months ended December 31, 2022 and 2021. Refer to the tables under "Grande Prairie Region – Karr Area" and "Grande Prairie Region – Wapiti Area" in the review of operations included in this document for the calculation of netback for the Grande Prairie Region and the Karr and Wapiti properties for the years ended December 31, 2022 and 2021 and for the three months ended December 31, 2022 and 2021.

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 expenditures related to Fox Drilling and Cavalier Energy and corporate capital expenditures, plus the change from the prior year in estimated future development capital included in the applicable 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, 2022, 2021 and 2020. Columns may not add due to rounding.

($ millions)	Total Company			
Proved Developed Producing	**2022**	2021	2020	3-year Total
Capital expenditures	**655**	275	221	1,151
Fox Drilling, Cavalier Energy and corporate	**(69)**	(6)	(2)	(77)
Change in estimated future development capital	**(10)**	(11)	54	34
F&D Capital – PDP	**577**	257	273	1,107
Total Proved	**2022**	2021	2020	3-year Total
Capital expenditures	**655**	275	221	1,151
Fox Drilling, Cavalier Energy and corporate	**(69)**	(6)	(2)	(77)
Change in estimated future development capital	**1,249**	221	(962)	509
F&D Capital – TP	**1,835**	490	(743)	1,582
Proved Plus Probable	**2022**	2021	2020	3-year Total
Capital expenditures	**655**	275	221	1,151
Fox Drilling, Cavalier Energy and corporate	**(69)**	(6)	(2)	(77)
Change in estimated future development capital	**1,176**	(93)	(1,196)	(112)
F&D Capital – P+P	**1,762**	176	(977)	961

($ millions)	Grande Prairie Region			
Proved Developed Producing	**2022**	2021	2020	3-year Total
Capital expenditures	**453**	229	197	879
Change in estimated future development capital	**(20)**	(22)	(4)	(45)
F&D Capital – PDP	**433**	207	193	833
Total Proved	**2022**	2021	2020	3-year Total
Capital expenditures	**453**	229	197	879
Change in estimated future development capital	**447**	(182)	(736)	(470)
F&D Capital – TP	**901**	47	(539)	409
Proved Plus Probable	**2022**	2021	2020	3-year Total
Capital expenditures	**453**	229	197	879
Change in estimated future development capital	**297**	(197)	(1,106)	(1,007)
F&D Capital – P+P	**750**	31	(909)	(128)

Non-GAAP Ratios

F&D costs, recycle ratio and netback and netback including risk management contract settlements presented on a $/Boe or $/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 and period; by (ii) the net changes to reserves in such reserves category from the prior period from extensions/improved recovery, technical revisions and economic factors, expressed in Boe. 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 forms for the years ended December 31, 2022, 2021 and 2020, which are 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" below for more information about this measure.

Recycle ratio is calculated by dividing the netback (a non-GAAP financial measure) per Boe for the period by the F&D costs for the period. 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 are the applicable F&D costs and recycle ratios for 2022, 2021 and 2020.

	Total Company					
	F&D ($/Boe)			Recycle Ratio (x)		
	2022	2021	2020	2022	2021	2020
Proved Developed Producing	$9.58	$6.22	$7.90	4.5x	4.3x	1.0x
Total Proved	$14.11	$6.72	na	3.0x	4.0x	na
Proved plus Probable	$14.87	$2.12	na	2.9x	12.6x	na

	Grande Prairie Region					
	F&D ($/Boe)			Recycle Ratio (x)		
	2022	2021	2020	2022	2021	2020
Proved Developed Producing	$9.61	$6.53	$8.79	5.1x	5.1x	1.3x
Total Proved	$9.95	$1.99	na	4.9x	16.8x	na
Proved plus Probable	$11.82	$0.59	na	4.2x	56.2x	na

Netback on a $/Boe or $/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 or $/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 and net debt are capital management measures that Paramount utilizes in managing its capital structure. These measures are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities. Refer to Note 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, 2022 and 2021 and (iii) a calculation of net debt as at December 31, 2022 and 2021.

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, 2022 and 2021:

Three months ended December 31 ($millions)	2022	2021
Cash from operating activities	306.9	191.8
Change in non-cash working capital	48.7	(20.1)
Geological and geophysical expense	2.1	2.9
Asset retirement obligations settled	7.0	7.0
Closure costs	–	–
Provisions	(24.0)	–
Settlements	–	(7.0)
Transaction and reorganization costs	–	–
Adjusted funds flow	340.7	174.6

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, 2022 and 2021:

Three months ended December 31 ($ millions)	2022	2021
Cash from operating activities	306.9	191.8
Change in non-cash working capital	48.7	(20.1)
Geological and geophysical expense	2.1	2.9
Asset retirement obligations settled	7.0	7.0
Closure costs	–	–
Provisions	(24.0)	–
Settlements	–	(7.0)
Transaction and reorganization costs	–	–
Adjusted funds flow	340.7	174.6
Capital expenditures	(169.6)	(65.7)
Geological and geophysical expense	(2.1)	(2.9)
Asset retirement obligation settled	(7.0)	(7.0)
Free cash flow	162.0	99.0

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, transportation and NGLs processing expenses, sales of commodities purchased and commodities purchased on a $/Bbl, $/Mcf or $/Boe basis.

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

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

ADVISORIES

Forward-looking Information

Certain statements in this 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:

- forecast sales volumes for 2023 and certain periods therein;
- planned capital expenditures in 2023 and the allocation thereof;
- planned abandonment and reclamation expenditures in 2023;
- forecast free cash flow in 2023;
- preliminary 2024 sales volumes, capital expenditure and free cash flow guidance;
- the Company's five-year outlook for 2027 average annual sales volumes, capital expenditures and cumulative free cash flow;
- the expectation that capital expenditures in 2023 and 2024 will be evenly split between sustaining and maintenance capital and growth;
- planned exploration, development and production activities, including the expected timing of drilling, completing and bringing new wells on production and the expected timing of completion and capacity of planned facilities;
- expected sales volumes in the Grande Prairie Region in the second half of 2023;
- go-forward DCET cost assumptions at Karr and Wapiti;
- expected sales volumes during certain periods at Willesden Green;
- internally estimated drilling locations and targeted plateau production volumes at Willesden Green and the time period over which targeted plateau production volumes may be maintained;
- expected reductions in emissions from a pilot project to replace pneumatic chemical pumps at Willesden Green and the expected generation of carbon credits from such project; 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 Russian invasion of the Ukraine;
- royalty rates, taxes and capital, operating, general & administrative and other costs;
- foreign currency exchange rates, interest rates and the rate and impacts of inflation;
- general business, economic and market conditions;
- the performance of wells and facilities;
- the availability to Paramount of the required capital to fund 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 expected and acceptable costs to carry out its activities;
- the ability of Paramount to secure adequate 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;
- 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 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 2024 sales volumes, capital expenditure and free cash flow guidance prior to finalization;
- the potential for changes to the Company's five-year outlook for 2027 average annual sales volumes, capital expenditures 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 production, future revenue, free cash flow, reserve additions, product yields (including condensate to natural gas ratios), resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate 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 expected and acceptable costs, including the potential effects of inflation and supply chain disruptions;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities);
- processing, pipeline, and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves estimates;
- general business, economic and market conditions;
- the ability to generate sufficient cash from operating activities to fund, or to otherwise finance, planned exploration, development and operational activities and meet current and future commitments and obligations (including 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 Indigenous 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 by the Company 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, 2022, which is available on SEDAR at www.sedar.com or on the Company's website at www.paramountres.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 2023 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 6, 2023 and effective December 31, 2022 (the "McDaniel Report"). The reserves referenced in this document are gross reserves. The price forecast used in the McDaniel Report is an average of the January 1, 2023 price forecasts for McDaniel and GLJ Petroleum Consultants Ltd. and the December 31, 2022 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. The reserves referenced in this document include reserves associated with the Kaybob Smoky and Kaybob South Duvernay properties that were subsequently disposed of in January 2023. Readers should refer to the Company's annual information form for the year ended December 31, 2022, which is available on SEDAR at www.sedar.com or on Paramount's website at www.paramountres.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. The annual information form also contains a description of the reserves associated with the Kaybob Smoky and Kaybob South Duvernay properties in the section titled "*Reserves and Other Oil and Gas Information - Impact of Kaybob Disposition*".

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", "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, 2022, the value ratio between crude oil and natural gas was approximately 23:1. 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 in the applicable category from technical revisions, economic factors and extensions/improved recovery, 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. 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.

This document contains information respecting Paramount's internal estimate of Duvernay drilling locations at Willesden Green. The referenced drilling locations represent future potential undeveloped gross locations as estimated effective December 31, 2022 by internal qualified reserves evaluators from Paramount. The referenced drilling locations were determined by Paramount's internal evaluators based on, among other matters, their assessment of available reservoir, geological and technical information, the economic thresholds necessary for development and potential future development plans. There is no certainty that the Company will drill any of the identified future potential undeveloped locations and there is no certainty that such locations will result in any reserves or production. The locations on which the Company will actually drill wells, including the number and timing thereof, will be dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil, NGLs and natural gas prices, costs, actual drilling results, additional reservoir, geological and technical information that is obtained and other factors. While certain of the estimated undeveloped locations have been de-risked by drilling existing wells in relative close proximity to such locations, many of the locations are further away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty as to whether wells will be drilled in such locations, and if wells are drilled in such locations there is more uncertainty that such wells will result in any reserves or production. There is no guarantee that any internally estimated future potential development locations will be included and assigned reserves in any future reserves report prepared for the Company.

Additional information respecting the Company's oil and gas properties and operations is provided in the Company's annual information form for the year ended December 31, 2022 which is available on SEDAR at www.sedar.com or on Paramount's website at www.paramountres.com.

Management's Discussion and Analysis
For the year ended December 31, 2022

This Management's Discussion and Analysis ("MD&A"), dated March 6, 2023 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, 2022 (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 year's presentation.

ABOUT PARAMOUNT

Paramount is an independent, publicly traded, liquids-rich natural gas 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 ("TSX") 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 the Kaybob North Duvernay development, the Kaybob North Montney oil development 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 also 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 cold flow heavy oil and in-situ thermal oil recovery; (ii) five triple-sized 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", "free cash flow", "net debt" and "net debt to adjusted funds flow", which are capital management measures used by Paramount; 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

	2022	2021	2020
FINANCIAL			
Petroleum and natural gas sales	**2,252.4**	1,383.6	626.7
Net income (loss)	**680.6**	236.9	(22.7)
Per share – basic ($/share)	***4.83***	1.77	*(0.17)*
Per share – diluted ($/share)	***4.63***	1.67	*(0.17)*
Cash from operating activities	**1,049.6**	482.1	80.9
Per share – basic ($/share) (1)	***7.45***	3.61	*0.61*
Per share – diluted ($/share) (1)	***7.14***	3.39	*0.61*
Adjusted funds flow (1)	**1,171.0**	499.8	150.0
Per share – basic ($/share)	***8.32***	*3.74*	*1.12*
Per share – diluted ($/share)	***7.97***	*3.51*	*1.12*
Free cash flow (1)	**471.1**	191.8	(113.7)
Per share – basic ($/share)	***3.35***	*1.44*	*(0.85)*
Per share – diluted ($/share)	***3.20***	*1.36*	*(0.85)*
Total assets	**4,337.3**	3,885.1	3,497.0
Investments in securities	**557.1**	372.1	59.5
Long-term debt	**159.4**	386.3	813.5
Net debt (1)	**161.2**	456.7	854.1
Total liabilities	**959.2**	1,278.7	1,459.2
Common shares outstanding (millions) (2)	**142.0**	139.2	132.3
OPERATING			
Sales volumes			
Natural gas (MMcf/d)	**294.7**	275.2	248.7
Condensate and oil (Bbl/d)	**33,908**	30,989	22,565
Other NGLs (Bbl/d)	**5,650**	5,147	4,325
Total (Boe/d)	**88,672**	82,001	68,340
% Liquids	***45%***	*44%*	39%
Realized prices (1)			
Natural gas ($/Mcf)	**6.24**	3.72	2.25
Condensate and oil ($/Bbl)	**117.07**	81.91	46.47
Other NGLs ($/Bbl)	**55.37**	41.84	15.63
Petroleum and natural gas sales ($/Boe)	**69.60**	46.23	25.05
Capital expenditures	**655.0**	274.6	220.2

(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 $/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.

(2) Common Shares are presented net of shares held in trust under the Company's restricted share unit plan (Common Shares): 2022: 0.8 million; 2021: 1.5 million; 2020: 1.9 million.

2022 OVERVIEW

Paramount's 2022 financial and operating results were highlighted by record annual production and cash flows. 2022 results included: (1)

- Record annual sales volumes of 88,672 Boe/d (45% liquids), an 8% increase relative to 2021.
- Record cash from operating activities of $1,049.6 million ($7.45 per basic share), a 118% increase compared to 2021.
- Record annual adjusted funds flow of $1,171.0 million ($8.32 per basic share), a 134% increase compared to 2021.
- Capital expenditures of $655.0 million, largely directed to the Grande Prairie Montney and Kaybob Duvernay developments.
- Record annual free cash flow of $471.1 million ($3.35 per basic share), a 146% increase compared to 2021.
- A more than doubling of the Company's regular monthly dividend from $0.06 to $0.125 per Common Share, representing the payment of an aggregate of $160.4 million in dividends in 2022.
- A reduction of net debt by $295.5 million to $161.2 million at year end, resulting in net debt to adjusted funds flow of 0.1x compared to 0.9x at December 31, 2021. In October 2022, the Company achieved its net debt target of $300 million.
- The achievement in September of monthly production in excess of 30,000 Boe/d at Wapiti for the first time.
- Abandonment and reclamation expenditures of $36.1 million, net of $10.0 million in funding under the Alberta Site Rehabilitation Program ("ASRP").

Paramount successfully executed its strategy of accretive acquisitions and divestitures in 2022:

- Acquired over 90,000 net acres of Duvernay lands at Willesden Green and 1,300 Boe/d of production (4.0 MMcf/d of shale gas, 580 Bbl/d of NGLs and 60 Bbl/d of tight oil) for approximately $38 million in the second quarter.
- Acquired approximately 90,000 net acres of Duvernay lands at Willesden Green and 1,700 Boe/d of production (4.6 MMcf/d of shale gas 700 Bbl/d of NGLs and 230 Bbl/d of tight oil) for approximately $60 million in the third quarter.
- Closed the disposition of non-core infrastructure assets comprised of approximately 60 kilometers of resource roads in the Bigstone area of the Kaybob Region for cash proceeds of approximately $64 million in the fourth quarter.

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(1) Adjusted funds flow, free cash flow, net debt and net debt to adjusted funds flow are capital management measures used by Paramount. Cash from operating activities per basic share, adjusted funds flow per basic share and free cash flow per basic share are supplementary financial measures. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures.

In January 2023, Paramount closed the sale of its Kaybob Smoky and Kaybob South Duvernay properties and certain other minor interests in the Kaybob Region for cash proceeds of approximately $370 million (the "Kaybob Disposition"). These properties had average sales volumes of approximately 4,700 Boe/d (13.8 MMcf/d of shale gas and 2,400 Bbl/d of NGLs) and a netback of approximately $21 million in the fourth quarter of 2022. (1) The assets and liabilities associated with the Kaybob Disposition have been presented as held for sale at December 31, 2022 in the Consolidated Financial Statements.

Following the Kaybob Disposition, in January 2023 Paramount paid a special cash dividend of $1.00 per Common Share and repaid all remaining drawings under its $1.0 billion revolving credit facility. At January 31, 2023, Paramount had a cash balance of approximately $110 million.

Although the Company leveraged robust commodity prices and operational success in 2022 to generate record cash flows, it continues to observe persistent, inflationary cost pressures across its operations. Paramount has responded to these pressures by seeking additional efficiencies in its capital program and operations and through advance planning and ordering aimed at mitigating future cost increases and potential shortages of supplies and services. However, these response measures have not fully offset the inflationary cost pressures that are currently being experienced. See "Risk Factors" in this MD&A for a further description of the risks posed by inflation and other risks that may affect the Company.

2022 RESULTS COMPARED TO GUIDANCE

On December 9, 2022, Paramount issued a press release, which is available at www.sedar.com or www.paramountres.com, announcing revised full year 2022 average sales volumes guidance of between 88,000 Boe/d and 90,000 Boe/d (45% liquids) and fourth quarter 2022 sales volumes guidance of between 97,000 Boe/d and 101,000 Boe/d (45% liquids). Full year 2022 average sales volumes were 88,672 Boe/d (45% liquids) and fourth quarter 2022 sales volumes were 97,370 Boe/d (45% liquids), in line with the revised guidance in each case.

Capital expenditures in 2022, which included the pre-ordering of approximately $25 million in materials for future development, totaled $655 million versus the $640 million upper range of previous guidance. Spending was largely directed to the Grande Prairie Montney and Kaybob Duvernay developments.

Free cash flow of $471.1 million in 2022 was $28.9 million less than previous guidance of $500 million, primarily as a result of higher than forecast capital expenditures and unscheduled outages that impacted production.

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(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.

REVISED GUIDANCE

Paramount is reaffirming its 2023 sales volumes guidance. Paramount is increasing its 2023 guidance for capital expenditures by $50 million as a result of anticipated inflationary cost pressures. Capital expenditures in 2023 and 2024 are expected to be evenly split between: (i) sustaining and maintenance capital; and (ii) growth. The Company is revising its 2023 free cash flow expectations to reflect lower natural gas prices, updated capital expenditures in 2023 and revised foreign exchange rates and other assumptions.

2023 Guidance

Annual average sales volumes (Boe/d)	100,000 to 105,000 (46% liquids)
First half average sales volumes (Boe/d)	96,000 to 101,000 (45% liquids)
Second half average sales volumes (Boe/d)	104,000 to 109,000 (47% liquids)
Capital expenditures	$700 to $750 million (~50% to growth) ($650 to $700 million prior guidance)
Abandonment and reclamation expenditures	$55 million
Free cash flow (1)	$375 million ($630 million prior guidance)

The Company's midpoint 2023 sustaining and maintenance capital program and regular monthly dividend would remain fully funded down to an average WTI price of about US$55/Bbl in 2023. The Company's total midpoint 2023 capital program and regular monthly dividend would remain fully funded down to an average WTI price of about US$71/Bbl in 2023. (2) Paramount remains committed to prudently managing its capital resources and has the flexibility to adjust its capital expenditure plans depending on commodity prices, inflationary cost pressures and other factors.

Paramount is reaffirming its preliminary 2024 guidance for sales volumes and capital expenditures. Paramount is revising its preliminary free cash flow expectations for 2024 to reflect lower natural gas prices and updated foreign exchange rates and other assumptions.

Preliminary 2024 Guidance (3)

Annual average sales volumes (Boe/d)	110,000 to 120,000 (48% liquids)
Capital expenditures	$700 to $800 million (~50% to growth)
Free cash flow (4)	$465 million ($620 million prior guidance)

(1) The stated free cash flow forecast is based on the following assumptions for 2023: (i) the midpoint of stated capital expenditures and sales volumes, (ii) $55 million in abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $55.20/Boe (US$80.00/Bbl WTI, US$3.50/MMBtu NYMEX, $3.08/GJ AECO), (v) a $US/$CAD exchange rate of $0.755, (vi) royalties of $8.30/Boe, (vii) operating costs of $11.40/Boe and (vii) transportation and processing costs of $3.55/Boe.
(2) Assuming no changes to the other forecast assumptions for 2023.
(3) All 2024 guidance is based on preliminary planning and current market conditions and is subject to change.
(4) The stated free cash flow estimate is based on the following assumptions for 2024: (i) the midpoint of stated capital expenditures and sales volumes, (ii) $40 million in abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $53.50/Boe (US$75.00/Bbl WTI, US$3.50/MMBtu NYMEX, $3.08/GJ AECO), (v) a $US/$CAD exchange rate of $0.755, (vi) royalties of $8.30/Boe, (vii) operating costs of $10.55/Boe and (vii) transportation and processing costs of $3.60/Boe.

FREE CASH FLOW PRIORITIES

Paramount's free cash flow priorities continue to be the maintenance of conservative leverage levels and the delivery of superior shareholder returns through a combination of dividends, investments in growth opportunities and opportunistic share buybacks.

CONSOLIDATED RESULTS

Net Income (Loss)

Paramount recorded net income of $680.6 million for the year ended December 31, 2022 compared to $236.9 million for the year ended December 31, 2021. Significant factors contributing to the change are shown below:

Year ended December 31	
Net income – 2021	**236.9**
• Higher netback in 2022, mainly due to higher commodity prices and sales volumes	590.2
• Provisions reversal in 2022 compared to an expense in 2021	45.9
• Lower interest and financing expense in 2022	40.7
• Loss on settlement of dissent payment entitlement in 2021	22.6
• Higher depletion, depreciation and impairment reversals expense in 2022	(152.9)
• Higher income tax expense in 2022	(99.6)
• Other	(3.2)
Net income – 2022	**680.6**

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 expense 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**

Cash From Operating Activities

Cash from operating activities for the year ended December 31, 2022 was $1,049.6 million compared to $482.1 million for the year ended December 31, 2021. Significant factors contributing to the change are shown below:

Year ended December 31	
Cash from operating activities – 2021	**482.1**
• Higher netback in 2022, mainly due to higher commodity prices and sales volumes	590.2
• Provisions reversal in 2022 compared to an expense in 2021	45.9
• Lower payments on risk management contract settlements in 2022	39.3
• Lower interest and financing expense in 2022	36.3
• Change in non-cash working capital	(131.1)
• Higher asset retirement obligations settled in 2022	(10.7)
• Other	(2.4)
Cash from operating activities – 2022	**1,049.6**

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**

Adjusted Funds Flow

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	2022	2021	2020
Cash from operating activities	**1,049.6**	482.1	80.9
Change in non-cash working capital (1)	**98.4**	(32.7)	17.9
Geological and geophysical expense (2)	**8.8**	8.0	8.5
Asset retirement obligations settled (1)	**36.1**	25.4	35.0
Provisions (3)	**(21.9)**	24.0	4.7
Settlements (3)	**–**	(7.0)	–
Transaction and reorganization costs (4)	**–**	–	3.0
Adjusted funds flow (5)	**1,171.0**	499.8	150.0
Adjusted funds flow ($/Boe) (6)	**36.18**	16.70	6.00

(1) Refer to the "Consolidated Statements of Cash Flows" in the Consolidated Financial Statements.
(2) Refer to Note 5 in the Consolidated Financial Statements.
(3) Refer to Note 16 in the Consolidated Financial Statements.
(4) Refer to the "Consolidated Statements of Comprehensive Income (Loss)" in the Company's consolidated financial statements as at and for the year ended December 31, 2021.
(5) 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.
(6) 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, 2022 was $1,171.0 million compared to $499.8 million for the year ended December 31, 2021. Significant factors contributing to the change are shown below:

Year ended December 31	
Adjusted funds flow – 2021	**499.8**
• Higher netback in 2022, mainly due to higher commodity prices and sales volumes	590.2
• Lower payments on risk management contract settlements in 2022	39.3
• Lower interest and financing expense in 2022	36.3
• Other	5.4
Adjusted funds flow – 2022	**1,171.0**

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 contracts 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**

Free Cash Flow

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	2022	2021	2020
Cash from operating activities	**1,049.6**	482.1	80.9
Change in non-cash working capital (1)	**98.4**	(32.7)	17.9
Geological and geophysical expense (2)	**8.8**	8.0	8.5
Asset retirement obligations settled (1)	**36.1**	25.4	35.0
Provisions (3)	**(21.9)**	24.0	4.7
Settlements (3)	**–**	(7.0)	–
Transaction and reorganization costs (4)	**–**	–	3.0
Adjusted funds flow	**1,171.0**	499.8	150.0
Capital expenditures (1)	**(655.0)**	(274.6)	(220.2)
Geological and geophysical expense (2)	**(8.8)**	(8.0)	(8.5)
Asset retirement obligations settled (1)	**(36.1)**	(25.4)	(35.0)
Free cash flow (5)	**471.1**	191.8	(113.7)

(1) Refer to the "Consolidated Statements of Cash Flows" in the Consolidated Financial Statements.
(2) Refer to Note 5 in the Consolidated Financial Statements.
(3) Refer to Note 16 in the Consolidated Financial Statements.
(4) Refer to the "Consolidated Statements of Comprehensive Income (Loss)" in the Company's consolidated financial statements as at and for the year ended December 31, 2021.
(5) 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.

Free cash flow for the year ended December 31, 2022 was $471.1 million compared to $191.8 million for the year ended December 31, 2021. Significant factors contributing to the change are shown below:

Year ended December 31	
Free cash flow – 2021	**191.8**
• Higher adjusted funds flow (described in "Adjusted Funds Flow" section above)	671.2
• Higher capital expenditures in 2022	(380.4)
• Higher asset retirement obligations settled in 2022	(10.7)
• Higher geological and geophysical expense in 2022	(0.8)
Free cash flow – 2022	**471.1**

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**

OPERATING RESULTS

Netback

Year ended December 31	2022		2021	
		($/Boe)(1)(2)		($/Boe)(1)(2)
Natural gas revenue (3)	671.1	6.24	373.3	3.72
Condensate and oil revenue (3)	1,448.9	117.07	926.5	81.91
Other NGLs revenue (3)	114.2	55.37	78.6	41.84
Royalty and other revenue (3)	18.2	–	5.2	–
Petroleum and natural gas sales (4)	2,252.4	69.60	1,383.6	46.23
Royalties (4)	(335.3)	(10.36)	(127.0)	(4.24)
Operating expense (4)	(407.1)	(12.58)	(340.4)	(11.37)
Transportation and NGLs processing (4)	(123.7)	(3.82)	(114.5)	(3.83)
Sales of commodities purchased (4)	272.0	8.41	75.5	2.52
Commodities purchased (4)	(267.0)	(8.25)	(76.1)	(2.54)
Netback (5)	1,391.3	43.00	801.1	26.77
Risk management contract settlements (6)	(179.0)	(5.53)	(218.3)	(7.29)
Netback including risk management contract settlements (7)	1,212.3	37.47	582.8	19.48

(1) Natural gas revenue shown per Mcf.
(2) When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures.
(3) Refer to Note 15 in the Consolidated Financial Statements. Royalty and other revenue for the year ended December 31, 2022 includes $11.9 million related to proceeds from a business interruption insurance claim.
(4) Refer to "Consolidated Statements of Comprehensive Income" in the Consolidated Financial Statements.
(5) Netback is a non-GAAP financial measure. Netback per $/Boe is a non-GAAP ratio. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures.
(6) Refer to Note 14 in the Consolidated Financial Statements.
(7) Netback including risk management contract settlements is a non-GAAP financial measure. Netback including risk management contract settlements per $/Boe is a non-GAAP ratio. Refer to the "Specified Financial Measures" section of this MD&A for more information on these measures.

Petroleum and natural gas sales were $2,252.4 million in 2022, an increase of $868.8 million from the prior year mainly due to higher commodity prices and sales volumes.

The impact of changes in 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, 2021	373.3	926.5	78.6	5.2	1,383.6
Effect of changes in prices	271.4	435.1	27.9	–	734.4
Effect of changes in sales volumes	26.4	87.3	7.7	–	121.4
Change in royalty and other revenue	–	–	–	13.0	13.0
Year ended December 31, 2022	**671.1**	**1,448.9**	**114.2**	**18.2**	**2,252.4**

Royalty and other revenue for the year ended December 31, 2022 includes $11.9 million related to proceeds from a business interruption insurance claim arising from outages at the third-party Wapiti natural gas processing plant (the "Wapiti Plant") in 2020 and 2021.

Petroleum and natural gas sales were $1,383.6 million in 2021, an increase of $756.9 million from 2020, mainly due to higher commodity prices and sales volumes.

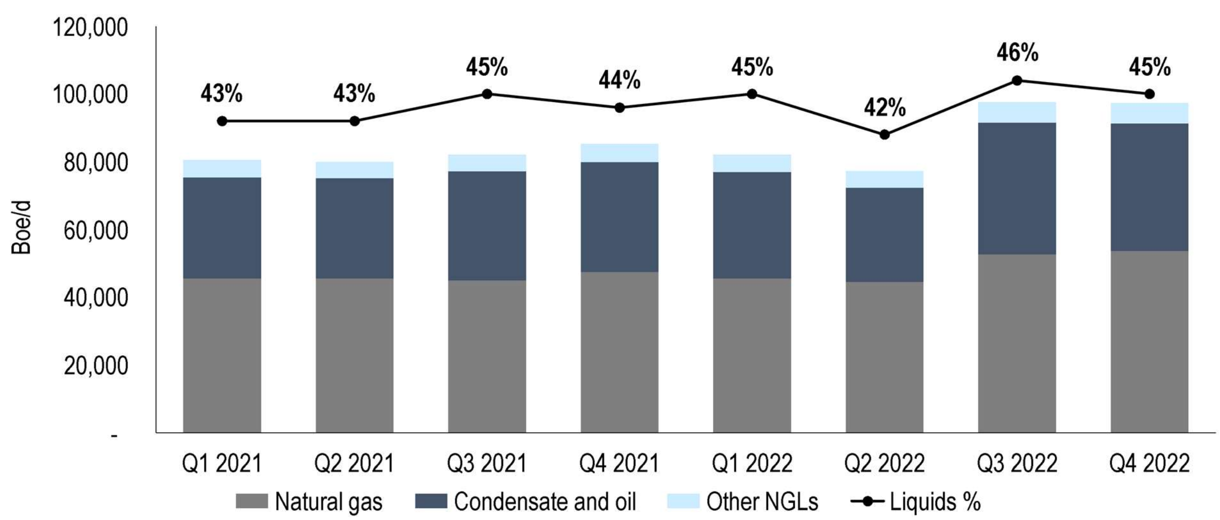
The impact of changes in prices and sales volumes on petroleum and natural gas sales are as follows:

	Natural gas	Condensate and oil	Other NGLs	Royalty and other	Total
Year ended December 31, 2020	204.9	383.8	24.7	13.3	626.7
Effect of changes in 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	–	–	–	(8.1)	(8.1)
Year ended December 31, 2021	**373.3**	**926.5**	**78.6**	**5.2**	**1,383.6**

Sales Volumes

	Year ended December 31											
	Natural gas (MMcf/d) (1)			Condensate and oil (Bbl/d) (1)			Other NGLs (Bbl/d) (1)			Total (Boe/d) (1)		
	2022	2021	% Chg	2022	2021	% Chg	2022	2021	% Chg	2022	2021	% Chg
Karr	**108.3**	109.2	(1)	**15,723**	17,858	(12)	**2,273**	2,330	(2)	**36,050**	38,381	(6)
Wapiti	**59.9**	31.8	*88*	**11,376**	7,400	*54*	**1,121**	773	*45*	**22,469**	13,488	*67*
Grande Prairie	**168.2**	141.0	*19*	**27,099**	25,258	*7*	**3,394**	3,103	*9*	**58,519**	51,869	*13*
Kaybob	**93.5**	97.2	*(4)*	**5,519**	4,779	*15*	**1,620**	1,612	–	**22,730**	22,588	*1*
Central Alberta and Other	**33.0**	37.0	*(11)*	**1,290**	952	*36*	**636**	432	*47*	**7,423**	7,544	*(2)*
Total	**294.7**	275.2	*7*	**33,908**	30,989	*9*	**5,650**	5,147	*10*	**88,672**	82,001	*8*

(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 averaged 88,672 Boe/d (45% liquids) for the year ended December 31, 2022, a new annual record for the Company, compared to 82,001 Boe/d (44% liquids) for the year ended December 31, 2021. The increase in annual production was mainly the result of production from new wells brought onstream towards the end of 2021 and during 2022 that more than offset the impact of additional downtime related to turnarounds and outages at third-party midstream facilities and associated infrastructure.

At Karr, 2022 sales volumes averaged 36,050 Boe/d (50% liquids) compared to 38,381 Boe/d (53% liquids) in 2021, largely due to Karr production being shut-in for approximately three weeks in the second quarter of 2022 as a result of planned turnarounds at two third-party midstream facilities in addition to unexpected infrastructure downtime in the fourth quarter of 2022. This impacted 2022 average production by an estimated 3,300 Boe/d. Production from 16 new wells brought onstream in 2022 in addition to 10 new wells brought onstream in the second half of 2021 offset declines.

Average sales volumes at Wapiti increased to 22,469 Boe/d (56% liquids) in 2022 compared to 13,488 Boe/d (61% liquids) in 2021. The increase was mainly due to 27 new wells being brought on production in 2022 in addition to three new wells being brought on production in the fourth quarter of 2021. Production at Wapiti in 2022 was impacted by an estimated 3,100 Boe/d due to a planned turnaround in the second quarter as well as unplanned outages and curtailments at the third-party Wapiti Plant and associated infrastructure at various times during the year.

Kaybob Region sales volumes averaged 22,730 Boe/d (31% liquids) in 2022 compared to 22,588 Boe/d (28% liquids) in 2021 as production from 14 (12.5 net) new wells brought onstream in 2022, including four Kaybob Montney gas wells, four Kaybob Smoky Duvernay wells and three Kaybob North Duvernay wells, more than offset declines.

Sales volumes in the Central Alberta and Other Region averaged 7,423 Boe/d (26% liquids) in 2022 compared to 7,544 Boe/d (18% liquids) in 2021 as the impacts of non-core property dispositions completed in 2021 of approximately 1,300 Boe/d (23% liquids) were mostly offset by additional production at Willesden Green from two acquisitions completed in 2022 that added approximately 1,100 Boe/d (44% liquids) of production.

Commodity Prices

Year Ended December 31	2022	2021	% Change
Natural Gas (1)			
Paramount realized natural gas price ($/Mcf)	6.24	3.72	68
AECO daily spot ($/GJ)	5.04	3.44	47
AECO monthly index ($/GJ)	5.27	3.38	56
Dawn ($/MMBtu)	7.92	4.55	74
NYMEX (US$/MMBtu)	6.51	3.72	75
Malin daily index (US$/MMBtu)	8.38	3.94	113
Condensate and Oil (1)			
Paramount realized condensate & oil price ($/Bbl)	117.07	81.91	43
Edmonton light sweet oil ($/Bbl)	119.73	80.31	49
Edmonton condensate ($/Bbl)	121.28	85.88	41
West Texas Intermediate crude oil (US$/Bbl)	94.23	67.91	39
Other NGLs (1)			
Paramount realized Other NGLs price ($/Bbl)	55.37	41.84	32
Conway – propane ($/Bbl)	59.63	54.87	9
Belvieu – butane ($/Bbl)	71.06	61.83	15
Foreign Exchange			
$CAD / 1 $US	1.30	1.25	4

(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-priced 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 20,000 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 include the impacts of sales under fixed-price physical contracts. In 2022, a total of 57,000 GJ/d and 12,000 MMBtu/d of natural gas was sold under fixed price physical contracts at prices of CAD$3.83/GJ and US$4.03/MMBtu, respectively (2021 – 102,000 GJ/d of natural gas at CAD$2.72/GJ).

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 had the following basis differential physical sales contracts at December 31, 2022:

	Volume	Location	Average price	Remaining term
Condensate	5,244 Bbl/d	FSPL (1)	WTI + US$0.50/Bbl	January 2023 – March 2023
Peace sweet crude oil	3,103 Bbl/d	Peace (2)	WTI – US$3.73/Bbl	January 2023 – December 2023

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

Subsequent to December 31, 2022, the Company entered into the following basis differential physical sales contracts:

	Volume	Location	Average price	Remaining term
Natural gas	20,000 MMBtu/d	AECO	NYMEX – US$0.94/MMBtu (1)	April 2023 – October 2023
Natural gas	10,000 MMBtu/d	Dawn	NYMEX – US$0.19/MMBtu (1)	April 2023 – October 2023

(1) "NYMEX" refers to NYMEX pricing at Henry Hub.

The Company's propane and butane volumes are sold under monthly and long-term contracts. The terms of contracts in place in 2022, along with higher benchmark prices, resulted in an increase in Paramount's realized Other NGLs prices in 2022 compared to 2021.

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	2022	2021
Fair value, beginning of year	5.4	(22.7)
Changes in fair value	(160.1)	(190.1)
Settlements paid by Paramount	166.5	218.2
Fair value, end of year	11.8	5.4

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

The following table summarizes the Company's financial and physical commodity contracts at March 6, 2023:

	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Average Price [(1)]
Oil					
Condensate – Basis (Physical Sale) (Bbl/d)	5,244	–	–	–	WTI + US$0.50/Bbl
Sweet Crude Oil – Basis (Physical Sale) (Bbl/d)	3,146	3,112	3,078	3,078	WTI – US$3.73/Bbl
Natural gas					
NYMEX Collars (MMBtu/d)	20,000	–	–	–	US$7.50/MMBtu (Floor) US$12.13/MMBtu (Ceiling)
AECO Collars (GJ/d)	20,000	–	–	–	CAD$7.25/GJ (Floor) CAD$9.60/GJ (Ceiling)
Chicago Index Swap (Sale) (MMBtu/d) [(2)]	5,000	–	–	–	Daily – US$0.09/MMBtu
AECO – Basis (Physical Sale) (MMBtu/d)	–	20,000	20,000	6,739	NYMEX – US$0.94/MMBtu
Dawn – Basis (Physical Sale) (MMBtu/d)	–	10,000	10,000	3,370	NYMEX – US$0.19/MMBtu

(1) Average price is calculated using a weighted average of notional volumes and prices.
(2) "Chicago Index" refers to Chicago Citygate Index pricing. These contracts convert price exposure of Chicago monthly index to daily index.

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. Changes in the fair value of the Company's foreign currency exchange contracts are as follows:

Year ended December 31	2022	2021
Fair value, beginning of year	0.4	–
Changes in fair value	(22.7)	0.3
Settlements paid by Paramount	12.5	0.1
Fair value, end of year	(9.8)	0.4

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

The Company had the following foreign currency exchange contracts at March 6, 2023:

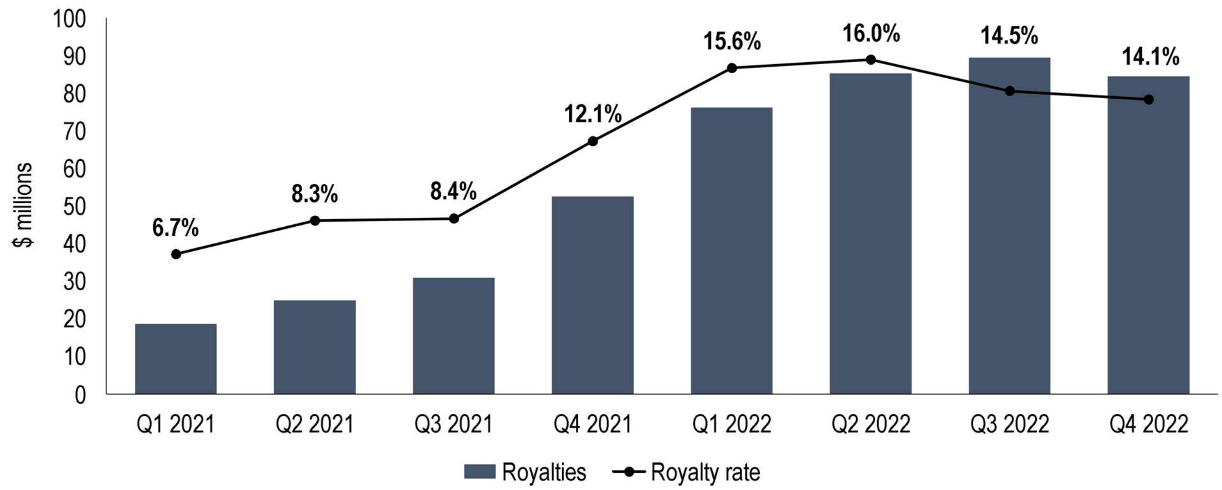
Instruments	Aggregate amount / notional	Average rate [(1)]	Remaining term
Forwards and Swaps (Sale)	US$60 million / month	1.3199 CAD$/US$1.00	January 2023 – June 2023
Swaps (Sale)	US$40 million / month	1.3427 CAD$/US$1.00	July 2023 – December 2023
Swaps (Sale)	US$30 million / month	1.3433 CAD$/US$1.00	January 2024 – June 2024
Swaps (Sale)	US$10 million / month	1.3400 CAD$/US$1.00	July 2024 – December 2024

(1) Average rate is calculated using a weighted average of notional volumes and foreign currency exchange rates.

Royalties

Year ended December 31	2022	Rate	2021	Rate
Royalties	335.3	15.0%	127.0	9.2%
$/Boe [(1)]	*10.36*		*4.24*	

(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.

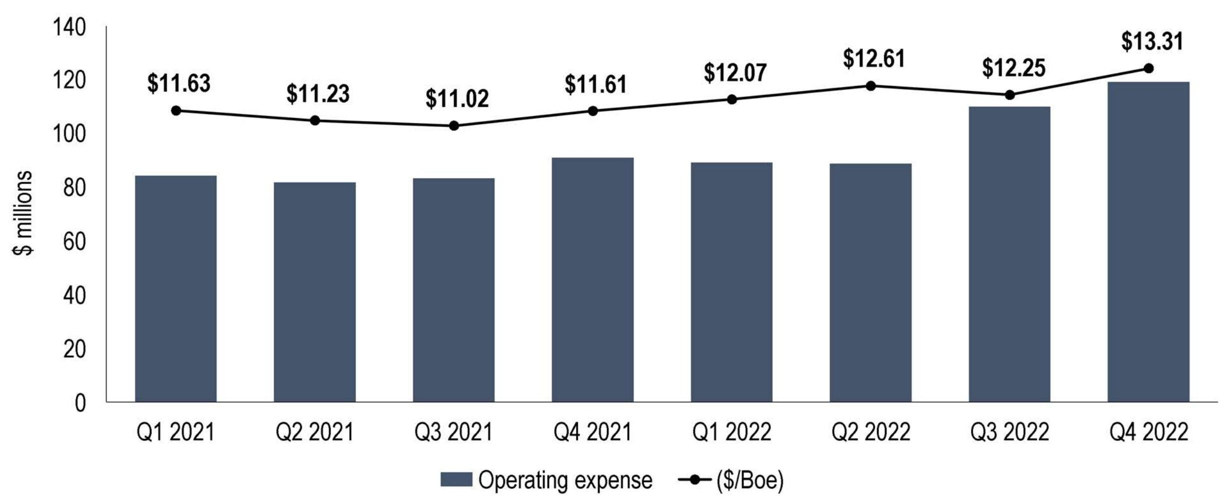


Royalties were $335.3 million for the year ended December 31, 2022 compared to $127.0 million in the same period in 2021. Royalties increased in 2022 due to both higher petroleum and natural gas sales revenue and higher royalty rates. Royalty rates increased in 2022 due to higher commodity prices and a greater proportion of Karr and Wapiti wells having fully utilized new well royalty incentives.

Operating Expense

Year ended December 31	2022	2021	% Change
Operating expense	407.1	340.4	20
$/Boe (1)	*12.58*	*11.37*	*11*

(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 $407.1 million for the year ended December 31, 2022 compared to $340.4 million in 2021. Operating expenses were higher in 2022 compared to 2021 due to higher processing fees, mainly related to increased production at Wapiti, increased maintenance activities, including workovers, and higher power and chemical costs. Operating expenses in 2022 include the impact of continued inflationary cost pressures across a number of categories, including processing fees, maintenance activities, chemicals and labour.

Operating costs at Karr were $149.3 million or $11.35/Boe for the year ended December 31, 2022 compared to $134.1 million or $9.57/Boe in 2021. Per unit operating costs in 2022 at Karr were higher mainly due to higher processing fees, increased maintenance activities, including workovers, as well as lower production in 2022.

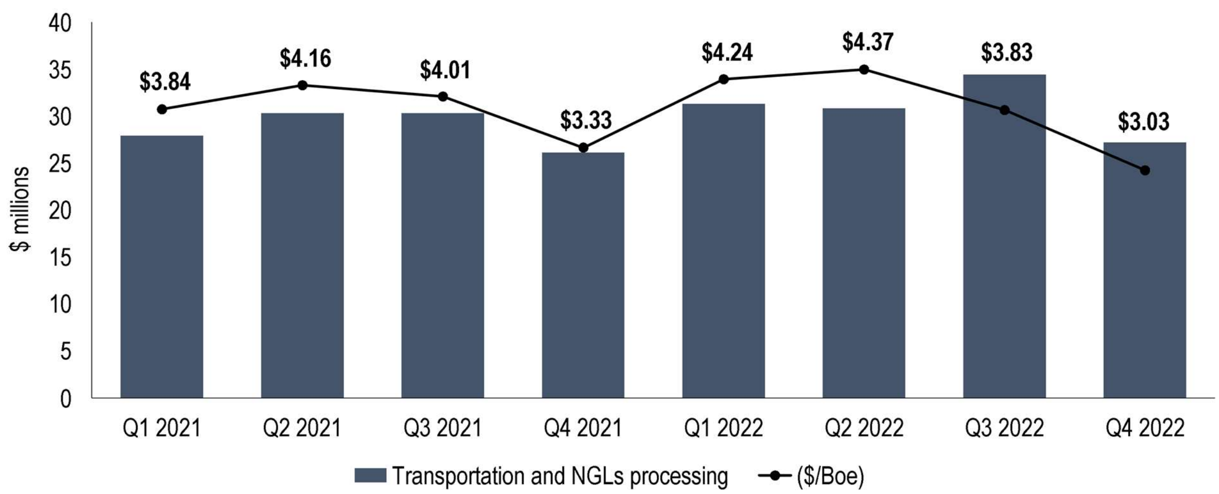
Operating costs at Wapiti were $98.3 million or $11.99/Boe for the year ended December 31, 2022 compared to $71.2 million or $14.46/Boe in 2021, mainly due to higher production in 2022.

Total Company operating expenses were $12.58/Boe for the year ended December 31, 2022 compared to $11.37/Boe in 2021, mainly due to the changes described above.

Transportation and NGLs Processing

Year ended December 31	2022	2021	% Change
Transportation and NGLs processing	123.7	114.5	8
$/Boe (1)	*3.82*	*3.83*	–

(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 $123.7 million for the year ended December 31, 2022 compared to $114.5 million in the same period in 2021. Transportation and NGLs processing costs increased in 2022 mainly as a result of higher production. Fourth quarter transportation and NGLs processing expense includes the impact of 13th month adjustments for volumes shipped in the year.

Sales of Commodities Purchased and Commodities Purchased

Year ended December 31	2022	2021	% Change
Sales of commodities purchased	272.0	75.5	260
Commodities purchased	(267.0)	(76.1)	251

Paramount purchases commodities from third parties to fulfill sales commitments and for blending purposes. For 2022, sales of commodities purchased increased to $272.0 million compared to $75.5 million in 2021. Sales of commodities purchased were higher in 2022 compared to 2021 mainly due to more volumes purchased from third parties and higher commodity prices.

Other Items

Year ended December 31	2022	2021
Depletion and depreciation	335.8	300.5
Change in asset retirement obligations	(39.8)	138.9
ASRP funding	(10.0)	(9.7)
Reversals of petroleum and natural gas asset impairments	–	(296.6)
Exploration and evaluation expense	30.6	38.9
Gain on sale of oil and gas assets	(65.6)	(72.1)
Accretion of asset retirement obligations	44.9	42.6

Depletion and depreciation expense was $335.8 million in 2022 compared to $300.5 million in 2021. The increase in depletion and depreciation expense in 2022 was mainly attributable to higher sales volumes.

For the year ended December 31, 2022, the Company recorded a recovery of $39.8 million (2021 – a charge of $138.9 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 were mainly due to revisions in the credit-adjusted risk-free rate used to discount obligations.

Exploration and evaluation expense was $30.6 million for the year ended December 31, 2022 compared to $38.9 million in 2021. The decrease in 2022 was primarily due to lower expenses related to expired mineral leases.

In October 2022, the Company closed the sale of approximately 60 kilometers of operated resources roads in the Kaybob cash-generating unit ("CGU") (the "Roads Disposition") for cash proceeds of $64.2 million. A gain of $62.4 million was recognized on the sale. Annual operating expenses are expected to increase by approximately $8 million as a result of the Roads Disposition (approximately $0.20/Boe based on the midpoint of forecast 2023 sales volumes).

Accretion of asset retirement obligations was $44.9 million for the year ended December 31, 2022, relatively consistent compared to $42.6 million for the same period in 2021.

Effective January 1, 2022, Northern CGU petroleum and natural gas assets were combined with the Central Alberta CGU to form the Central Alberta and Other CGU.

Paramount sold its non-operated Birch assets in northeast British Columbia in 2021, which were included in the Central Alberta and Other CGU, for proceeds of approximately $85 million. A $14.0 million reversal of previously recorded impairment charges and a gain of $36.1 million was recognized in 2021 in connection with the sale. These assets 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.

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

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. For additional information on impairment reversals in 2021, refer to Note 6 in the Consolidated Financial Statements.

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 2022 and 2021, Paramount focused its activities in the Zama area, which was shut-in during 2019.

Abandonment and reclamation expenditures for the year ended December 31, 2022 totaled $36.1 million, net of $10.0 million in funding under the ASRP. Activities in 2022 included the abandonment of 74 wells, including 42 under the Company’s ongoing area-based closure program at Zama.

The Company's budget for abandonment and reclamation activities in 2023 remains unchanged at approximately $55 million. The majority of 2023 activities will be performed at Zama and Hawkeye.

As at December 31, 2022, estimated undiscounted, uninflated asset retirement obligations were $1,296.0 million (December 31, 2021 – $1,318.7 million). As at December 31, 2022, the Company’s discounted asset retirement obligations were $540.1 million (discounted at 8.5 percent per annum and using an inflation rate of 2.0 percent per annum) compared to $651.1 million as at December 31, 2021 (discounted at 7.0 percent per annum and using an inflation rate of 2.0 percent per annum). For further details concerning the Company’s asset retirement obligations, refer to Note 9 in the Consolidated Financial Statements.

OTHER ASSETS

Investments in Securities

As at December 31	2022	2021
Level one fair value hierarchy securities ("Level One Securities")	477.3	300.2
Level three fair value hierarchy securities ("Level Three Securities")	79.8	71.9
	557.1	372.1

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.

At December 31, 2022, the Company owned 37.3 million common shares of NuVista Energy Ltd. ("NuVista Shares") (December 31, 2021 – 39.8 million) having a carrying value of $464.9 million (December 31, 2021 – $276.7 million), which were included in Investments in Securities and classified as Level One Securities.

As a result of changes in the fair value estimates of its investments in securities, the Company recorded $235.3 million, before tax, to other comprehensive income ("OCI") for the year ended December 31, 2022.

In 2022, Paramount disposed of 2.5 million NuVista Shares as well as investments in other Level One and Level Three Securities for aggregate proceeds of $56.8 million, resulting in $12.9 million of accumulated net gains, net of tax, being reclassified from reserves to retained earnings.

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

Year ended December 31	2022	2021
Investments in securities, beginning of year	372.1	59.5
Changes in fair value of Level One Securities	222.4	256.0
Changes in fair value of Level Three Securities	12.9	60.8
Changes in fair value of warrants – recorded in earnings	0.4	–
Acquired – cash	1.8	1.0
Acquired – non-cash	4.3	–
Proceeds of dispositions – cash	(52.8)	(5.2)
Proceeds of dispositions – non-cash	(4.0)	–
Investments in securities, end of year	557.1	372.1

Fox Drilling

Fox Drilling owns five triple-sized drilling rigs that are used to drill Company wells, four of which are walking rigs. A fifth walking rig is currently under construction. 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. All 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, 2022, Cavalier Energy holds approximately 1.357 million gross (1.312 million net) acres of land located primarily in the Athabasca and Peace River regions of Alberta that are prospective for cold flow heavy oil and in-situ thermal oil recovery. Cavalier Energy holds 276,000 net acres with Clearwater and Bluesky cold flow heavy oil potential. 9 (2.0 net) Clearwater wells were drilled on these lands by a third-party in 2022 under farmout arrangements.

Other Strategic Investments

Paramount also holds approximately 104,000 gross (86,000 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	2022	2021
General and administrative	42.7	41.6
Share-based compensation	25.3	18.8
Interest and financing	6.4	47.1
Settlement of dissent payment entitlement	–	22.6
Deferred income tax expense	185.2	85.6
Other	(27.5)	16.2

General and administrative expense was $42.7 million for the year ended December 31, 2022, relatively similar to the same period in 2021.

Interest and financing expense was lower for the year ended December 31, 2022 compared to 2021 mainly due to lower average debt balances under the Company's financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility"). Interest and financing expense in 2022 was reduced by $10.2 million related to the impacts of $500 million of floating-to-fixed interest rate swaps, which were terminated in December 2022 for a payment to the Company of $10.3 million.

In June 2021, Paramount received $67 million cash in settlement of dissent proceedings with respect to one of its prior investments. A loss of $22.6 million was recognized on the settlement.

Deferred income tax expense was $185.2 million for the year ended December 31, 2022 compared to $85.6 million recorded in 2021. The Company has tax pools in excess of $4 billion at December 31, 2022, the majority of which are immediately deductible.

Other

Provisions

The Company recorded provisions of $24.0 million in 2021 and $1.6 million in the second quarter of 2022 with respect to arrangements with a service provider. Paramount had unsettled claims against the same service provider with respect to certain related matters which were not recognized in the Consolidated Financial Statements.

The Company reached an agreement with the service provider with respect to these arrangements and certain related matters, resulting in a recovery of $24.0 million being recorded to provisions in the fourth quarter of 2022.

Settlements

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

CAPITAL EXPENDITURES AND LAND AND PROPERTY ACQUISITIONS

Capital Expenditures

Year ended December 31	2022	2021
Drilling, completion, equipping and tie-ins	494.6	257.6
Facilities and gathering	97.6	11.0
Drilling rigs	22.1	4.7
Corporate	40.7	1.3
Capital expenditures	**655.0**	274.6
Grande Prairie Region	453.3	228.6
Kaybob Region	131.2	14.5
Central Alberta and Other Region	2.1	25.2
Fox Drilling and Cavalier	27.7	5.0
Corporate	40.7	1.3
Capital expenditures	**655.0**	274.6

Land and Property Acquisitions

Year ended December 31	2022	2021
Land and property acquisitions	**145.8**	5.4

Capital expenditures totaled $655.0 million for the year ended December 31, 2022 compared to $274.6 million in 2021. Expenditures in 2022 were mainly directed to drilling and completion programs in the Grande Prairie and Kaybob Regions. Significant capital program activities in 2022 included the following:

- At Karr, the Company drilled 23 (18.8) net wells, including 5.0 (0.8 net) non-operated wells, and completed and brought-on production 16 (12.6 net) wells, including 4 (0.6 net) non-operated wells. The Company also brought into service one new water disposal well and completed debottlenecking initiatives to support higher production in 2023.

- At Wapiti, Paramount drilled and completed 25 (25.0 net) wells and brought-on production 27 (27.0 net) wells.

- In the Kaybob Region, the Company drilled 13 (11.5 net) wells, completed 15 (13.5 net) wells and brought-on production 14 (12.5 net) wells.

- Fox Drilling and Cavalier capital expenditures included $16.8 million related to construction of a fifth super-spec walking rig that is expected to be completed and deployed in mid-2023.

- Corporate capital expenditures included $25.6 million related to the purchases of materials for future development.

For the year ended December 31, 2022, land and property acquisitions included $98.3 million for acquisitions completed in the Willesden Green Duvernay and $24.1 million for an asset acquisition in the Grande Prairie Region.

Cavalier entered into a farm-out agreement with Rubellite Energy Inc. ("Rubellite") in 2022 under which Rubellite may earn up to a 60 percent working interest in 61.25 gross sections of Cavalier’s Clearwater formation rights in the Peavine area of Alberta by drilling wells or making certain qualifying capital expenditures. A director and significant shareholder of Paramount is also the President and Chief Executive Officer, a director and significant shareholder of Rubellite.

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. These measures are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities. Readers are referred to the Specified Financial Measures section of this MD&A and Note 18 – Capital Structure of the Consolidated Financial Statements for important additional information concerning these measures.

As at December 31	2022	2021
Cash and cash equivalents	**(2.5)**	(1.7)
Accounts receivable (1)	**(216.5)**	(139.7)
Prepaid expenses and other	**(9.1)**	(7.3)
Accounts payable and accrued liabilities	**229.9**	219.1
Long-term debt	**159.4**	386.3
Net Debt	**161.2**	456.7

(1) Excludes accounts receivable relating to lease incentives and subleases (December 31, 2022 – $6.7 million, December 31, 2021 – $2.2 million).

Net debt does not account for the $557.1 million carrying value of the Company's investments in securities as at December 31, 2022.

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, available capacity under the Paramount Facility, the terms of which are described further below, and, from time to time, cash and cash equivalents.

Based on the forecasts of 2023 sales volumes and the pricing assumptions set out in this MD&A under "Revised Guidance", Paramount expects to fully fund budgeted 2023 capital expenditures and abandonment and reclamation expenditures 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 certain periods should expenditures exceed cash from operating activities and cash and cash equivalents.

The ability of cash from operating activities to satisfy the Company's funding requirements in 2023 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 currency 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 the first quarter of 2022, Paramount sold a portion of its investments in securities for aggregate cash proceeds of $51.0 million and, in October 2022, the Company completed the Roads Disposition for cash proceeds of $64.2 million. Proceeds from these dispositions were used to reduce indebtedness under the Paramount Facility. In January 2023, Paramount completed the Kaybob Disposition for cash proceeds of $370 million and repaid all remaining drawings 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.

Paramount Facility

The Paramount Facility is a $1.0 billion financial covenant-based senior secured revolving bank credit facility. The maturity date of the Paramount Facility is May 3, 2026. At Paramount's request, the credit limit of the Paramount Facility can be increased by up to $250 million 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, Canadian Dollar Offered Rates, or Adjusted Term SOFR, 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 also 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, 2022.

The Company had undrawn letters of credit outstanding under the Paramount Facility totaling $2.2 million at December 31, 2022 (December 31, 2021 – $2.3 million) 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. The PSG is valid to June 30, 2023. At December 31, 2022, $24.2 million in undrawn letters of credit were outstanding under the LC Facility (December 31, 2021 – $38.7 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 and redeemable by Paramount, in whole or in part, at any time prior to the Maturity Date.

In November 2021, Paramount delivered notices to redeem all $35.0 million of the Convertible Debentures at a redemption price of 107.50 percent of the principal amount 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 5.2 million 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.

Cash Flow Hedges

The Company had the following electricity swaps at December 31, 2022:

Contract type	Aggregate notional	Remaining term	Average fixed contract rate	Reference	Fair value
Electricity Swaps	240 MWh/d (1)	January 2023 – December 2023	$84.00/MWh	AESO Pool Price (2)	7.9
Electricity Swaps	240 MWh/d (1)	January 2024 – December 2024	$66.13/MWh	AESO Pool Price (2)	2.4
Electricity Swaps	120 MWh/d (1)	January 2025 – December 2025	$73.25/MWh	AESO Pool Price (2)	0.5
					10.8

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

In 2022, the Company entered into floating-to-fixed price swaps on 120 MWh/d of electricity, which were designated as cash flow hedges, to manage exposure to variable market prices by fixing the underlying AESO Pool Price on a portion of the Company's anticipated power requirements for 2023, 2024 and 2025 (2021 – floating-to-fixed electricity price swaps on 120 MWh/d of electricity for 2023 and 2024).

The Company has classified its electricity swaps as cash flow hedges and applied hedge accounting. There were no changes to the critical terms of the hedging relationships and no hedge ineffectiveness was identified on the floating-to-fixed electricity swaps.

In December 2022, Paramount terminated all $500 million notional amount of its floating-to-fixed interest rate swaps for aggregate cash proceeds to the Company of $10.3 million. For the year ended December 31, 2022, interest and financing expense was reduced by $10.2 million relating to the impact of the Company's floating-to-fixed interest rate swaps.

Share Capital

At March 3, 2023, Paramount had 142.1 million Common Shares outstanding (net of 0.8 million Common Shares held in trust under the Company's restricted share unit plan) and 11.2 million options to acquire Common Shares outstanding, of which 2.9 million options are exercisable.

For the year ended December 31, 2022, Paramount issued 2.1 million Common Shares on the exercise of stock options to acquire Common Shares.

Dividends

In July 2021, Paramount implemented a regular monthly dividend with respect to its Common Shares. Dividends declared for the year ended December 31, 2022 totaled $1.13 per Common Share (2021 – $0.20 per Common Share). The Company paid a special cash dividend of $1.00 per Common Share on January 25, 2023 to shareholders of record on January 18, 2023 and regular monthly dividends of $0.125 per Common Share on January 31, 2023 and February 28, 2023 to shareholders of record on January 16, 2023 and February 15, 2023, respectively.

Normal Course Issuer Bid

In June 2022, Paramount implemented a normal course issuer bid (the "2022 NCIB") under which the Company may purchase up to 7.6 million Common Shares for cancellation. The 2022 NCIB will terminate on the earlier of June 29, 2023 and the date on which the maximum number of Common Shares that can be acquired pursuant to the 2022 NCIB are purchased. Any purchases of Common Shares under the 2022 NCIB will be effected through the facilities of the TSX or alternative Canadian trading systems at the market price at the time of purchase. The Company has not made any purchases of Common Shares under the 2022 NCIB to date.

Paramount previously implemented a normal course issuer bid in June 2021 (the "2021 NCIB") under which the Company purchased and cancelled 197,500 Common Shares at a total cost of $2.7 million ($13.69 per share). The 2021 NCIB expired on June 29, 2022.

FOURTH QUARTER RESULTS

Netback

Three months ended December 31	2022		2021	
		($/Boe)(1)(2)		($/Boe)(1)(2)
Natural gas revenue	194.2	6.56	124.7	4.76
Condensate and oil revenue	375.1	108.50	281.1	94.46
Other NGLs revenue	27.3	48.25	27.4	54.61
Royalty and other revenue	1.1	–	1.3	–
Petroleum and natural gas sales	597.7	66.72	434.5	55.40
Royalties	(84.4)	(9.43)	(52.5)	(6.69)
Operating expense	(119.2)	(13.31)	(91.0)	(11.61)
Transportation and NGLs processing	(27.2)	(3.03)	(26.1)	(3.33)
Sales of commodities purchased	102.7	11.47	22.1	2.82
Commodities purchased	(100.4)	(11.21)	(22.3)	(2.85)
Netback (3)	369.2	41.21	264.7	33.74
Risk management contract settlements	(23.0)	(2.57)	(72.4)	(9.23)
Netback including risk management contract settlements (4)	346.2	38.64	192.3	24.51

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

Fourth quarter 2022 petroleum and natural gas sales were $597.7 million, an increase of $163.2 million from the fourth quarter of 2021, 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, 2021	124.7	281.1	27.4	1.3	434.5
Effect of changes in prices	53.2	48.5	(3.6)	–	98.1
Effect of changes in sales volumes	16.3	45.5	3.5	–	65.3
Change in royalty and other revenue	–	–	–	(0.2)	(0.2)
Three months ended December 31, 2022	194.2	375.1	27.3	1.1	597.7

Sales Volumes

	Three months ended December 31											
	Natural gas (MMcf/d) (1)			Condensate and oil (Bbl/d) (1)			Other NGLs (Bbl/d) (1)			Total (Boe/d) (1)		
	2022	2021	% Chg	2022	2021	% Chg	2022	2021	% Chg	2022	2021	% Chg
Karr	111.9	124.0	(10)	15,308	18,521	(17)	2,247	2,449	(8)	36,209	41,629	(13)
Wapiti	78.0	34.9	123	13,838	7,757	78	1,384	827	67	28,225	14,406	96
Grande Prairie	189.9	158.9	20	29,146	26,278	11	3,631	3,276	11	64,434	56,035	15
Kaybob	96.9	92.4	5	6,661	4,539	47	1,671	1,788	(7)	24,477	21,725	13
Central Alberta and Other	35.1	33.5	5	1,773	1,525	16	841	398	111	8,459	7,505	13
Total	321.9	284.8	13	37,580	32,342	16	6,143	5,462	12	97,370	85,265	14

(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 2022 averaged 97,370 Boe/d (45% liquids) compared to 85,265 Boe/d (44% liquids) in the fourth quarter of 2021.

At Karr, fourth quarter 2022 sales volumes averaged 36,209 Boe/d (48% liquids) compared to 41,629 Boe/d (50% liquids) in the same period in 2021, largely due to unexpected infrastructure downtime and extreme cold weather in the fourth quarter of 2022 that impacted quarterly average production by approximately 2,900 Boe/d. Production from 16 new wells brought onstream in 2022 partially offset declines. In early 2023, four new wells were brought onstream.

Sales volumes at Wapiti increased to 28,225 Boe/d (54% liquids) in the fourth quarter of 2022 compared to 14,406 Boe/d (60% liquids) in the fourth quarter of 2021. The increase mainly resulted from development activities where the Company brought 27 new wells on production in 2022, in addition to three new wells being brought onstream in the fourth quarter of 2021. Production at Wapiti in the fourth quarter of 2022 was impacted by an estimated 3,400 Boe/d due to unplanned outages and curtailments at the third-party Wapiti Plant and associated infrastructure.

Kaybob Region sales volumes were 24,477 Boe/d (34% liquids) in the fourth quarter of 2022, 13 percent higher than the fourth quarter of 2021, mainly due to 14 (12.5 net) new wells being brought on-stream in 2022, including four Kaybob Smoky Duvernay wells, four Kaybob Montney gas wells and three Kaybob North Duvernay wells.

Sales volumes in the Central Alberta and Other Region were 8,459 Boe/d (31% liquids) in the fourth quarter of 2022 compared to 7,505 Boe/d (26% liquids) in the same period in 2021, mainly due to two Willesden Green Duvernay acquisitions completed in 2022 adding approximately 2,800 Boe/d (44% liquids) of production, which more than offset declines.

Commodity Prices

Three months ended December 31	2022	2021	% Change
Natural Gas (1)			
Paramount realized natural gas price ($/Mcf)	**6.56**	4.76	*38*
AECO daily spot ($/GJ)	**4.85**	4.41	*10*
AECO monthly index ($/GJ)	**5.29**	4.68	*13*
Dawn ($/MMBtu)	**7.14**	5.86	*22*
NYMEX (US$/MMBtu)	**6.09**	4.85	*26*
Malin daily index (US$/MMBtu)	**14.36**	5.36	*168*
Condensate and Oil (1)			
Paramount realized condensate & oil price ($/Bbl)	**108.50**	94.46	*15*
Edmonton light sweet oil ($/Bbl)	**108.15**	92.14	*17*
Edmonton condensate ($/Bbl)	**115.50**	100.17	*15*
West Texas Intermediate crude oil (US$/Bbl)	**82.64**	77.19	*7*
Other NGLs (1)			
Paramount realized Other NGLs price ($/Bbl)	**48.25**	54.61	*(12)*
Conway – propane ($/Bbl)	**46.45**	65.95	*(30)*
Belvieu – butane ($/Bbl)	**55.77**	78.18	*(29)*
Foreign Exchange			
$CAD / 1 $US	**1.36**	1.26	*8*

(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 include the impacts of sales under fixed-price physical contracts. In the fourth quarter of 2022, a total of 27,000 GJ/d and 7,000 MMBtu/d of natural gas was sold under fixed price physical contracts at prices of CAD$3.78/GJ and US$4.03/MMBtu, respectively (fourth quarter of 2021 – 117,000 GJ/d at CAD$3.16/GJ).

The Company's propane and butane volumes are sold under monthly and long-term contracts. The terms of contracts in place in 2022 resulted in a smaller decrease in Paramount's realized Other NGLs prices in the fourth quarter of 2022 relative to changes in benchmark prices.

Royalties were $84.4 million in the fourth quarter of 2022, $31.9 million higher than the same period in 2021, primarily as a result of both higher royalty rates and higher petroleum and natural gas sales. Royalty rates increased in 2022 due to higher commodity prices and a greater proportion of Karr and Wapiti wells having fully utilized new well royalty incentives.

Operating expenses were $119.2 million in the fourth quarter of 2022 compared to $91.0 million in the same period in 2021. Operating expenses were higher in 2022 compared to 2021 mainly due to higher processing fees related to increased production at Wapiti, higher power costs and increased workover and maintenance activities.

Operating costs at Karr were $38.5 million or $11.55/Boe in the fourth quarter of 2022 compared to $36.0 million or $9.38/Boe in the same period in 2021. Per unit operating costs at Karr in the fourth quarter of 2022 were higher mainly due to increased processing fees and lower production in 2022.

Operating costs at Wapiti were $31.4 million or $12.11/Boe in the fourth quarter of 2022 compared to $18.9 million or $14.26/Boe in the same period in 2021, mainly due to higher production in 2022.

Total company per unit operating expenses were $13.31/Boe in the fourth quarter of 2022 compared to $11.61/Boe, mainly due to the changes described above.

Transportation and NGLs processing costs were $27.2 million in the fourth quarter of 2022 compared to $26.1 million in the same period in 2021, mainly due to higher production volumes.

Sales of commodities purchased were $102.7 million in the fourth quarter of 2022 compared $22.1 million in the same period in 2021, mainly due to greater volumes purchased for balancing and blending purposes from third-parties and higher commodity prices.

Net Income

Three months ended December 31	2022	2021
Petroleum and natural gas sales	597.7	434.5
Royalties	(84.4)	(52.5)
Sales of commodities purchased	102.7	22.1
Revenue	616.0	404.1
Gain on risk management contracts	8.1	14.1
	624.1	418.2
Expenses		
Operating expense	119.2	91.0
Transportation and NGLs processing	27.2	26.1
Commodities purchased	100.4	22.3
General and administrative	13.6	11.9
Share-based compensation	13.1	7.7
Depletion and depreciation	95.2	100.4
Exploration and evaluation	4.7	9.2
Gain on sale of oil and gas assets	(63.7)	–
Interest and financing expense (income)	(2.2)	9.0
Accretion of asset retirement obligations	11.6	10.5
Other	(23.4)	(7.5)
	295.7	280.6
Income before tax	328.4	137.6
Income tax expense		
Deferred	68.5	36.6
Net income	259.9	101.0
Net income per common share ($/share)		
Basic	1.83	0.75
Diluted	1.76	0.70

Paramount recorded net income of $259.9 million for the three months ended December 31, 2022 compared to $101.0 million in the same period in 2021. Significant factors contributing to the change are shown below:

Three months ended December 31	
Net income – 2021	**101.0**
• Higher netback in 2022, mainly due to higher commodity prices and sales volumes	104.5
• Gain on sale of oil and gas assets in 2022	63.7
• Provisions reversal in 2022	24.0
• Interest and financing income in 2022 compared to expense in 2021, mainly due to the termination of interest rate swaps in 2022	11.2
• Higher income tax expense in 2022	(31.9)
• Lower gain on risk management contracts in 2022 compared to 2021	(6.0)
• Other	(6.6)
Net income – 2022	259.9

Cash From Operating Activities

Three months ended December 31	2022	2021
Operating activities		
Net income	259.9	101.0
Add (deduct):		
Items not involving cash	102.7	77.7
Asset retirement obligations settled	(7.0)	(7.0)
Change in non-cash working capital	(48.7)	20.1
Cash from operating activities	306.9	191.8

Cash from operating activities for the three months ended December 31, 2022 was $306.9 million compared to $191.8 million for the same period in 2021. Significant factors contributing to the change are shown below:

Three months ended December 31	
Cash from operating activities – 2021	**191.8**
• Higher netback in 2022, mainly due to higher commodity prices and sales volumes	104.5
• Lower payments on risk management contract settlements in 2022	49.4
• Provisions reversal in 2022	24.0
• Interest and financing income in 2022 compared to expense in 2021, mainly due to the termination of interest rate swaps in 2022	13.5
• Change in non-cash working capital	(68.8)
• Other	(7.5)
Cash from operating activities – 2022	306.9

Adjusted Funds Flow

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:

Three months ended December 31	2022	2021
Cash from operating activities	306.9	191.8
Change in non-cash working capital	48.7	(20.1)
Geological and geophysical expense	2.1	2.9
Asset retirement obligations settled	7.0	7.0
Provisions	(24.0)	–
Settlements	–	(7.0)
Adjusted funds flow (1)	340.7	174.6
Adjusted funds flow ($/Boe) (2)	38.02	22.25

(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 2022 was $340.7 million compared to $174.6 million in the same period in 2021. Significant factors contributing to the change are shown below:

Three months ended December 31	
Adjusted funds flow – 2021	**174.6**
• Higher netback in 2022, mainly due to higher commodity prices and sales volumes	104.5
• Lower payments on risk management contract settlements in 2022	49.4
• Interest and financing income in 2022 compared to expense in 2021, mainly due to the termination of interest rate swaps in 2022	13.5
• Other	(1.3)
Adjusted funds flow – 2022	**340.7**

Free Cash Flow

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:

Three months ended December 31	2022	2021
Cash from operating activities	**306.9**	191.8
Change in non-cash working capital	**48.7**	(20.1)
Geological and geophysical expense	**2.1**	2.9
Asset retirement obligations settled	**7.0**	7.0
Provisions	**(24.0)**	–
Settlements	**–**	(7.0)
Adjusted funds flow	**340.7**	174.6
Capital expenditures	**(169.6)**	(65.7)
Geological and geophysical expense	**(2.1)**	(2.9)
Asset retirement obligation settled	**(7.0)**	(7.0)
Free cash flow [1]	**162.0**	99.0

(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.

Free cash flow in the fourth quarter of 2022 was $162.0 million compared to $99.0 million in the same period in 2021. Significant factors contributing to the change are shown below:

Three months ended December 31	
Free cash flow – 2021	**99.0**
• Higher adjusted funds flow (described in "Adjusted Funds Flow" section above)	166.1
• Higher capital expenditures in 2022	(103.9)
• Lower geological and geophysical expense in 2022	0.8
Free cash flow – 2022	**162.0**

Capital Expenditures by Region

Three months ended December 31	2022	2021
Grande Prairie Region	135.8	57.7
Kaybob Region	11.4	3.8
Central Alberta and Other Region	1.0	2.6
Fox and Cavalier	12.1	1.0
Corporate	9.3	0.6
Capital expenditures	169.6	65.7

Capital expenditures in the fourth quarter of 2022 totaled $169.6 million, with the majority of spending directed towards drilling and completion programs in the Grande Prairie Region.

QUARTERLY INFORMATION

	2022				2021			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	597.7	618.9	536.2	499.6	434.5	369.2	299.8	280.1
Revenue	616.0	607.4	493.7	472.2	404.1	369.6	288.4	270.1
Net income (loss)	259.9	221.9	182.2	16.6	101.0	292.7	(74.3)	(82.5)
Per share – basic ($/share)	*1.83*	*1.57*	*1.29*	*0.12*	*0.75*	*2.20*	*(0.56)*	*(0.62)*
Per share – diluted ($/share)	*1.76*	*1.51*	*1.24*	*0.11*	*0.70*	*2.06*	*(0.56)*	*(0.62)*
Cash from operating activities (1)	306.9	248.9	318.9	174.9	191.8	97.0	112.1	81.3
Per share – basic ($/share)	*2.17*	*1.76*	*2.26*	*1.25*	*1.42*	*0.73*	*0.84*	*0.61*
Per share – diluted ($/share)	*2.08*	*1.69*	*2.16*	*1.20*	*1.33*	*0.68*	*0.84*	*0.61*
Adjusted funds flow (1)	340.7	334.3	258.3	237.8	174.6	148.4	86.0	90.9
Per share – basic ($/share)	*2.40*	*2.37*	*1.83*	*1.70*	*1.29*	*1.12*	*0.65*	*0.69*
Per share – diluted ($/share)	*2.31*	*2.27*	*1.75*	*1.63*	*1.21*	*1.04*	*0.65*	*0.69*
Free cash flow (1)	162.0	137.5	68.3	103.4	99.0	73.8	(2.4)	21.6
Per share – basic ($/share)	*1.14*	*0.97*	*0.48*	*0.74*	*0.73*	*0.56*	*(0.02)*	*0.16*
Per share – diluted ($/share)	*1.10*	*0.93*	*0.46*	*0.71*	*0.69*	*0.52*	*(0.02)*	*0.16*
Dividends declared ($/share)	0.35	0.30	0.28	0.20	0.14	0.06	–	–
Sales volumes								
Natural gas (MMcf/d)	321.9	315.9	267.2	272.9	284.8	269.7	273.1	273.1
Condensate and oil (Bbl/d)	37,580	38,804	27,750	31,375	32,342	32,177	29,543	29,854
Other NGLs (Bbl/d)	6,143	6,144	5,021	5,276	5,462	5,017	4,938	5,170
Total (Boe/d)	97,370	97,601	77,312	82,137	85,265	82,150	79,995	80,540
Liquids %	*45%*	*46%*	*42%*	*45%*	*44%*	*45%*	*43%*	*43%*
Realized prices (1)								
Natural gas ($/Mcf)	6.56	6.39	6.75	5.18	4.76	3.89	3.01	3.14
Condensate and oil ($/Bbl)	108.50	112.56	134.65	117.53	94.46	84.42	77.96	69.20
Other NGLs ($/Bbl)	48.25	51.20	62.80	61.64	54.61	47.05	32.11	32.29
Petroleum and natural gas ($/Boe)	66.72	68.92	76.22	67.59	55.40	48.86	41.18	38.64

(1) Adjusted funds flow and free cash flow are capital management measures 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 commodity prices.

- Fourth quarter 2022 earnings include deferred income tax expense of $68.5 million, a provision reversal of $24.0 million and $6.9 million related to the impacts of $500 million of floating-to-fixed interest rate swaps that were terminated in December 2022.
- Third quarter 2022 earnings include the impacts of record production volumes and petroleum and natural gas sales revenue.
- Second quarter 2022 earnings include deferred income tax expense of $55.5 million, a recovery of $46.9 million related to changes in the discounted carrying value of asset retirement obligations in respect of properties that had a nil carrying value and a $41.3 million loss on risk management contracts.
- First quarter 2022 earnings include a $152.0 million loss on risk management contracts.
- 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 $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.

OTHER INFORMATION

Contractual Obligations

Paramount had the following contractual obligations at December 31, 2022: (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	–	–	161.9	–	**161.9**
Transportation and processing commitments (2)	242.9	470.8	421.1	828.0	**1,962.8**
Asset retirement obligations (3)	37.7	71.2	63.5	1,123.7	**1,296.1**
Finance lease and other commitments (4)	18.2	20.5	6.9	24.6	**70.2**
	298.8	**562.5**	**653.4**	**1,976.3**	**3,491.0**

(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 $0.7 million at December 31, 2022 (December 31, 2021 – $13.0 million).
(3) Undiscounted, uninflated asset retirement obligations estimated as at December 31, 2022. Estimated costs and timing of settlement are revised from time-to-time based on new information.
(4) Includes future commitments of $13.8 million relating to new leases expected to commence in 2023.

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 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.

NEW AND UPDATED ACCOUNTING POLICIES AND STANDARDS

Future Changes in Accounting Standards

The International Accounting Standards Board has announced amendments to accounting standards and interpretations and new accounting standards that are effective for annual periods beginning on or after January 1, 2023. 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.

DISCLOSURE CONTROLS AND PROCEDURES

As of the year ended December 31, 2022, 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 under the supervision 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, 2022.

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, under the supervision 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, 2022. 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, 2022.

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, 2022, 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 Annual Information Form, which is available under the Company's profile on SEDAR at www.sedar.com.

Global economies, including that of Canada, have recently experienced inflation across broad categories of goods and services. In addition, the Russian invasion of the Ukraine has resulted in additional volatility in global financial and commodity markets and has increased the potential for supply chain constraints and disruptions.

The Company continues to monitor its supply chain and the availability and cost of materials and third-party services. While the Company has not, to date, experienced material interruptions in the availability of supplies or services, it is experiencing persistent, inflationary cost pressures across its operations. Paramount has responded to these pressures by seeking additional efficiencies in its capital program and operations and through advance planning and ordering aimed at mitigating future cost increases and potential shortages of supplies and services. However, these response measures have not fully offset the inflationary cost pressures that have been experienced.

The existence and economic impact of these conditions and the response thereto increases the Company's exposure to the risks described in the Risk Factors of the Annual Information Form section under "Volatility of NGLs, Natural Gas and Oil Prices and Price Differentials", "Uncertainty as to Costs", "Availability of Equipment, Materials and Services", "Market Price of Common Shares", "Investment Risk" and "Hedging, Interest Rates and Foreign Currency Exchange Rates".

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.

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

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.

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 regulatory, partner or other approvals 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: 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.

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.

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 credit-adjusted risk-free discount and inflation rates 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.

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.

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 fair value of the stock 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.

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.

PRODUCT TYPE INFORMATION

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. 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.

	2022				2021				Annual		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	2022	2021	2020
SALES VOLUMES – TOTAL COMPANY BY PRODUCT TYPE											
Shale gas (MMcf/d)	**260.0**	253.8	203.7	213.1	220.4	207.1	205.8	197.8	232.9	207.9	156.7
Conventional natural gas (MMcf/d)	**61.9**	62.1	63.5	59.8	64.4	62.6	67.3	75.3	61.8	67.3	92.0
Natural gas (MMcf/d)	**321.9**	315.9	267.2	272.9	284.8	269.7	273.1	273.1	294.7	275.2	248.7
Condensate (Bbl/d)	**34,616**	35,747	25,374	29,064	29,797	29,670	26,784	27,017	31,228	28,328	19,334
Other NGLs (Bbl/d)	**6,143**	6,144	5,021	5,276	5,462	5,017	4,938	5,170	5,650	5,147	4,325
NGLs (Bbl/d)	**40,759**	41,891	30,395	34,340	35,259	34,687	31,722	32,187	36,878	33,475	23,659
Tight oil (Bbl/d)	**629**	449	402	437	497	475	494	479	480	487	462
Light and medium crude oil (Bbl/d)	**2,335**	2,608	1,974	1,874	2,048	2,032	2,265	2,358	2,200	2,174	2,768
Crude oil (Bbl/d)	**2,964**	3,057	2,376	2,311	2,545	2,507	2,759	2,837	2,680	2,661	3,230
Total (Boe/d)	**97,370**	97,601	77,312	82,137	85,265	82,150	79,995	80,540	88,672	82,001	68,340

SALES VOLUMES – BY REGION BY PRODUCT TYPE											
GRANDE PRAIRIE REGION											
Shale gas (MMcf/d)	**188.4**	188.2	138.8	151.4	156.5	145.8	132.2	120.6	166.9	138.8	77.2
Conventional natural gas (MMcf/d)	**1.5**	1.4	1.0	1.1	2.4	2.2	2.1	2.0	1.3	2.2	1.4
Natural gas (MMcf/d)	**189.9**	189.6	139.8	152.5	158.9	148.0	134.3	122.6	168.2	141.0	78.6
Condensate (Bbl/d)	**29,146**	30,610	22,511	26,042	26,272	26,639	24,086	23,974	27,095	25,253	15,991
Other NGLs (Bbl/d)	**3,631**	3,758	2,914	3,267	3,276	3,274	2,874	2,984	3,394	3,103	1,964
NGLs (Bbl/d)	**32,777**	34,368	25,425	29,309	29,548	29,913	26,960	26,958	30,489	28,356	17,955
Light and medium crude oil (Bbl/d)	**–**	5	5	6	6	9	4	–	4	5	14
Crude oil (Bbl/d)	**–**	5	5	6	6	9	4	–	4	5	14
Total (Boe/d)	**64,434**	65,981	48,736	54,737	56,035	54,586	49,345	47,385	58,519	51,869	31,076

KAYBOB REGION											
Shale gas (MMcf/d)	**41.9**	38.5	37.9	35.7	35.6	36.9	39.3	42.1	38.5	38.6	43.8
Conventional natural gas (MMcf/d)	**55.0**	54.8	56.7	53.6	56.8	54.4	58.0	65.8	55.0	58.6	82.1
Natural gas (MMcf/d)	**96.9**	93.3	94.6	89.3	92.4	91.3	97.3	107.9	93.5	97.2	125.9
Condensate (Bbl/d)	**4,354**	4,157	2,092	2,130	2,184	2,072	2,319	2,611	3,192	2,295	2,885
Other NGLs (Bbl/d)	**1,671**	1,666	1,585	1,558	1,788	1,415	1,569	1,677	1,620	1,612	1,812
NGLs (Bbl/d)	**6,025**	5,823	3,677	3,688	3,972	3,487	3,888	4,288	4,812	3,907	4,697
Tight oil (Bbl/d)	**262**	208	253	322	355	368	354	342	261	355	301
Light and medium crude oil (Bbl/d)	**2,045**	2,434	1,946	1,832	2,000	1,979	2,224	2,321	2,066	2,129	2,709
Crude oil (Bbl/d)	**2,307**	2,642	2,199	2,154	2,355	2,347	2,578	2,663	2,327	2,484	3,010
Total (Boe/d)	**24,477**	24,021	21,642	20,726	21,725	21,054	22,688	24,938	22,730	22,588	28,685

	2022				2021				Annual		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	2022	2021	2020
CENTRAL ALBERTA AND OTHER REGION											
Shale gas (MMcf/d)	29.7	27.1	27.0	26.0	28.2	24.4	34.3	35.1	27.5	30.5	35.7
Conventional natural gas (MMcf/d)	5.4	5.9	5.8	5.1	5.3	6.0	7.2	7.5	5.5	6.5	8.5
Natural gas (MMcf/d)	35.1	33.0	32.8	31.1	33.5	30.4	41.5	42.6	33.0	37.0	44.2
Condensate (Bbl/d)	1,116	980	771	892	1,341	959	379	433	941	781	458
Other NGLs (Bbl/d)	841	720	522	451	398	328	495	509	636	432	549
NGLs (Bbl/d)	1,957	1,700	1,293	1,343	1,739	1,287	874	942	1,577	1,213	1,007
Tight oil (Bbl/d)	367	241	149	115	142	107	140	136	219	131	161
Light and medium crude oil (Bbl/d)	290	169	23	36	42	44	37	37	130	40	46
Crude oil (Bbl/d)	657	410	172	151	184	151	177	173	349	171	207
Total (Boe/d)	8,459	7,599	6,934	6,674	7,505	6,510	7,962	8,217	7,423	7,544	8,579

SALES VOLUMES – KARR BY PRODUCT TYPE											
Shale gas (MMcf/d)	111.5	112.9	94.2	112.8	122.5	113.0	106.3	89.1	107.8	107.9	55.6
Conventional natural gas (MMcf/d)	0.4	0.5	0.4	0.5	1.5	1.4	1.3	1.1	0.5	1.3	0.7
Natural gas (MMcf/d)	111.9	113.4	94.6	113.3	124.0	114.4	107.6	90.2	108.3	109.2	56.3
Condensate (Bbl/d)	15,308	16,799	13,551	17,246	18,521	18,328	18,458	16,095	15,723	17,858	10,028
Other NGLs (Bbl/d)	2,247	2,394	1,978	2,475	2,449	2,477	2,281	2,108	2,273	2,330	1,361
NGLs (Bbl/d)	17,555	19,193	15,529	19,721	20,970	20,805	20,739	18,203	17,996	20,188	11,389
Total (Boe/d)	36,209	38,088	31,295	38,611	41,629	39,878	38,679	33,230	36,050	38,381	20,777

SALES VOLUMES – WAPITI BY PRODUCT TYPE											
Shale gas (MMcf/d)	76.9	75.3	44.6	38.6	34.0	32.8	25.9	31.5	59.1	30.9	21.6
Conventional natural gas (MMcf/d)	1.1	0.9	0.6	0.6	0.9	0.8	0.8	0.9	0.8	0.9	0.7
Natural gas (MMcf/d)	78.0	76.2	45.2	39.2	34.9	33.6	26.7	32.4	59.9	31.8	22.3
Condensate (Bbl/d)	13,838	13,811	8,960	8,796	7,751	8,311	5,628	7,879	11,372	7,395	5,963
Other NGLs (Bbl/d)	1,384	1,364	936	792	827	797	593	876	1,121	773	603
NGLs (Bbl/d)	15,222	15,175	9,896	9,588	8,578	9,108	6,221	8,755	12,493	8,168	6,566
Light and medium crude oil (Bbl/d)	–	5	5	6	6	9	4	–	4	5	14
Crude oil (Bbl/d)	–	5	5	6	6	9	4	–	4	5	14
Total (Boe/d)	28,225	27,893	17,441	16,126	14,406	14,708	10,666	14,155	22,469	13,488	10,299

The Company forecasts that 2023 annual sales volumes will average between 100,000 Boe/d and 105,000 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 2023 sales volumes are expected to average between 96,000 Boe/d and 101,000 Boe/d (55% shale gas and conventional natural gas combined, 38% light and medium crude oil, tight oil and condensate combined and 7% other NGLs). Second half 2023 sales volumes are expected to average between 104,000 Boe/d and 109,000 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). The Company's preliminary 2024 guidance provides for annual sales volumes that will average between 110,000 Boe/d and 120,000 Boe/d (52% shale gas and conventional natural gas combined, 41% light and medium crude oil, tight oil and condensate combined and 7% other NGLs).

SPECIFIED FINANCIAL MEASURES

Non-GAAP Financial Measures

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

Netback equals petroleum and natural gas sales (the most directly comparable measure disclosed in the Company's primary financial statements) plus sales of commodities purchased less royalties, operating expense, transportation and NGLs processing expense and commodities purchased. Sales of commodities purchased and commodities purchased are treated as corporate items and not allocated to individual regions or properties. Netback is used by investors and Management to compare the performance of the Company's producing assets between periods.

Netback including risk management contract settlements equals netback after including (or deducting) risk management contract settlements received (paid). Netback including risk management contract settlements is used by investors and Management to assess the performance of the producing assets after incorporating Management's risk management strategies. Refer to "Operating Results – Netback" and "Fourth Quarter Results – Netback" in this MD&A for calculations of netback and netback including risk management contract settlements for the years ended December 31, 2022 and 2021 and for the three months ended December 31, 2022 and 2021.

Non-GAAP Ratios

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

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

Capital Management Measures

Adjusted funds flow, free cash flow, 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 the (i) the years ended December 31, 2022, 2021 and 2020 is provided in this MD&A under "Consolidated Results – Adjusted Funds Flow" and (ii) the three months ended December 31, 2022, and 2021 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 the (i) the years ended December 31, 2022, 2021 and 2020 is provided in this MD&A under "Consolidated Results – Free Cash Flow" and (ii) the three months ended December 31, 2022, and 2021 is provided in this MD&A under "Fourth Quarter Results – Free Cash Flow".

A calculation of net debt as at December 31, 2022 and 2021 is provided in this MD&A under "Liquidity and Capital Resources". At December 31, 2022, Paramount's net debt to adjusted funds flow (determined on a trailing four quarter basis) was 0.1x (December 31, 2021 – 0.9x).

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) petroleum and natural gas sales, adjusted funds flow, revenue, royalties, operating expenses, transportation and NGLs processing expenses, sales of commodities purchased and commodities purchased 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, revenue, royalties, operating expenses, transportation and NGLs processing expenses, sales of commodities purchased and commodities purchased on a $/Bbl, $/Mcf or $/Boe basis are calculated by dividing petroleum and natural gas sales, adjusted funds flow, revenue, royalties, operating expenses, transportation and NGLs processing expenses, sales of commodities purchased and commodities purchased, as applicable, over the referenced period by the aggregate units (Bbl, Mcf or Boe) produced 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:

- forecast sales volumes for 2023 and certain periods therein;
- planned capital expenditures in 2023 and the allocation thereof;
- forecast free cash flow in 2023;
- planned abandonment and reclamation expenditures and activities in 2023;
- preliminary 2024 sales volumes, capital expenditure and free cash flow guidance;
- the expected impact on operating expenses of the Roads Disposition;
- the expectation that the Company will be able to fund budgeted capital expenditures and net abandonment and reclamation expenditures in 2023 with cash from operating activities;
- the expectation that changes to accounting standards and interpretations will not have a material impact on the Company's Consolidated Financial Statements on adoption;
- the anticipation that legal proceedings will not have a material impact on Paramount's financial position;
- the potential payment of future dividends; and
- the potential impacts of inflation and the Russian invasion of the Ukraine.

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 Russian invasion of the Ukraine;
- royalty rates, taxes and capital, operating, general & administrative and other costs;
- foreign currency exchange rates, interest rates and the rate and impacts of inflation;
- general business, economic and market conditions;
- the performance of wells and facilities;
- the availability to Paramount of the required capital to fund 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 expected and acceptable costs to carry out its activities;
- the ability of Paramount to secure adequate 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;
- 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 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 2024 sales volumes, capital expenditures and free cash flow guidance prior to finalization;
- changes in foreign currency exchange rates, interest rates and the rate of inflation;
- the uncertainty of estimates and projections relating to future production, revenue, free cash flow, reserves additions, product yields (including condensate to natural gas ratios), resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate 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 expected and acceptable costs, including the potential effects of inflation and supply chain disruptions;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities);
- processing, pipeline and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves estimates;
- general business, economic and market conditions;
- the ability to generate sufficient cash from operating activities to fund, or to otherwise finance planned exploration, development and operational activities and meet current and future commitments and obligations (including 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 Indigenous 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 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, 2022, 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 2023 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		**Natural Gas**	
Bbl	Barrels	Mcf	Thousands of cubic feet
Bbl/d	Barrels per day	MMcf/d	Millions of cubic feet per day
NGLs	Natural gas liquids	GJ	Gigajoules
Condensate	Pentane and heavier hydrocarbons	GJ/d	Gigajoules per day
WTI	West Texas Intermediate	MMBtu	Millions of British Thermal Units
		MMBtu/d	Millions of British Thermal Units per day
Oil Equivalent		NYMEX	New York Mercantile Exchange
Boe	Barrels of oil equivalent	AECO	AECO-C reference price
Boe/d	Barrels of oil equivalent per day		

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, 2022, the value ratio between crude oil and natural gas was approximately 23:1. 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.

Consolidated Financial Statements
As at December 31, 2022 and 2021 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 6, 2023

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, 2022 and 2021, and the consolidated statements of comprehensive income, consolidated statements of cash flows and consolidated statements of shareholders' equity for the years ended December 31, 2022 and 2021, 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, 2022 and 2021, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2022 and 2021 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.

Valuation of level three investments in securities

As discussed in notes 1(m) and 7 in the consolidated financial statements, the Company measures its Level 1 and Level 3 investments in securities at fair value with the corresponding fair value change recognized in other comprehensive income. The valuation is performed by the Company using a fair value hierarchy: Level 1 are valuations based on quoted prices (unadjusted) in active markets; and level 3 are valuations based on unobservable inputs for the assets. As at December 31, 2022, the Company held level three investments in securities of $79.8 million. The level three investments in 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 operational results of the entities. The valuation of the level three investments in securities is a key audit matter given the inherently subjective nature of significant unobservable inputs that require judgment.	To test the Company's estimated valuation of level three investments in securities, we performed the following audit procedures, amongst others: • We involved our internal valuation specialists to evaluate the appropriateness of the underlying valuation methodology used for each significant investment. • Our internal valuation specialists assessed the implied valuation metrics derived from the Company’s valuation conclusions for each investment against that of observable public company and transactions, as appropriate. • Confirmed the number of shares owned in securities with the entities. • We evaluated the completeness and accuracy of the Company’s disclosures relating to investments to assess appropriateness and completeness with IFRS disclosure requirements.

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 6, 2023

CONSOLIDATED BALANCE SHEETS
($ millions)

As at December 31	Note	2022	2021
ASSETS			
Current assets			
Cash and cash equivalents	17	2.5	1.7
Accounts receivable	14	223.2	141.9
Risk management – current	14	19.7	5.8
Prepaid expenses and other		9.1	7.3
Assets held for sale	4	251.7	–
		506.2	156.7
Lease receivable	9	–	0.5
Investments in securities	7	557.1	372.1
Risk management – long-term	14	2.9	0.7
Exploration and evaluation	5	485.7	539.9
Property, plant and equipment, net	6	2,456.3	2,269.7
Deferred income tax	13	329.1	545.5
		4,337.3	3,885.1
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	14	229.9	219.1
Risk management – current	14	9.8	6.5
Asset retirement obligations and other – current	9	40.7	30.4
Liabilities associated with assets held for sale	4	2.0	–
		282.4	256.0
Long-term debt	8	159.4	386.3
Risk management – long-term	14	–	3.1
Asset retirement obligations and other – long-term	9	517.4	633.3
		959.2	1,278.7
Commitments and contingencies	20		
Shareholders' equity			
Share capital	10	2,267.1	2,251.9
Retained earnings (accumulated deficit)		517.6	(15.5)
Reserves	11	593.4	370.0
		3,378.1	2,606.4
		4,337.3	3,885.1

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 6, 2023

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

($ millions, except as noted)

Year ended December 31	Note	2022	2021
Petroleum and natural gas sales		2,252.4	1,383.6
Royalties		(335.3)	(127.0)
Sales of commodities purchased		272.0	75.5
Revenue	15	2,189.1	1,332.1
Loss on risk management contracts	14	(182.7)	(189.8)
		2,006.4	1,142.3
Expenses			
Operating expense		407.1	340.4
Transportation and NGLs processing		123.7	114.5
Commodities purchased		267.0	76.1
General and administrative		42.7	41.6
Share-based compensation	12	25.3	18.8
Depletion, depreciation and impairment reversals	6	286.0	133.1
Exploration and evaluation	5	30.6	38.9
Gain on sale of oil and gas assets	5,6	(65.6)	(72.1)
Interest and financing	8,14	6.4	47.1
Accretion of asset retirement obligations	9	44.9	42.6
Settlement of dissent payment entitlement	7	–	22.6
Other	16	(27.5)	16.2
		1,140.6	819.8
Income before tax		865.8	322.5
Income tax expense			
Deferred	13	185.2	85.6
		185.2	85.6
Net income		680.6	236.9
Other comprehensive income, net of tax	11		
Items that will be reclassified to net income			
Change in fair value of cash flow hedges, net of tax		20.4	8.9
Reclassification to net income, net of tax		(6.8)	7.7
Items that will not be reclassified to net income			
Change in fair value of securities, net of tax	7	208.3	284.8
Comprehensive income		902.5	538.3
Net income per common share ($/share)	10		
Basic		4.83	1.77
Diluted		4.63	1.67

See the accompanying notes to these Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS
($ millions)

Year ended December 31	Note	2022	2021
Operating activities			
Net income		680.6	236.9
Add (deduct):			
Items not involving cash	17	503.5	237.9
Asset retirement obligations settled	9	(36.1)	(25.4)
Change in non-cash working capital		(98.4)	32.7
Cash from operating activities		1,049.6	482.1
Financing activities			
Net repayment of revolving long-term debt	8	(229.5)	(430.2)
Lease liabilities – principal repayments	9	(7.3)	(7.7)
Convertible debentures issued, net of issue costs	8	–	34.9
Dividends	10	(160.4)	(27.4)
Common Shares issued, net of issue costs	10	21.2	10.6
Common Shares repurchased under NCIB	10	–	(2.7)
Common Shares purchased under RSU plan	12	(17.2)	(10.8)
Cash used in financing activities		(393.2)	(433.3)
Investing activities			
Capital expenditures	5,6	(655.0)	(274.6)
Land and property acquisitions	5,6	(145.8)	(5.4)
Proceeds of disposition	6,7	119.1	170.7
Investments	7	(1.8)	(1.0)
Proceeds from dissent payment entitlement, net	7	–	66.8
Change in non-cash working capital		29.5	(8.2)
Cash used in investing activities		(654.0)	(51.7)
Net increase (decrease)		2.4	(2.9)
Foreign exchange on cash and cash equivalents		(1.6)	–
Cash and cash equivalents, beginning of year		1.7	4.6
Cash and cash equivalents, end of year		2.5	1.7

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	2022		2021	
		Shares (millions)		*Shares (millions)*	
Share capital					
Balance, beginning of year		*139.2*	2,251.9	*132.3*	2,207.4
Issued on exercise of Paramount Options	10,12	*2.1*	27.9	*1.5*	13.7
Issued on conversion of convertible debentures	8,10	–	–	*5.2*	35.5
Common Shares repurchased and cancelled under NCIB	10	–	–	*(0.2)*	(2.7)
Change in Common Shares for RSU plan	12	*0.7*	(12.7)	*0.4*	(2.0)
Balance, end of year		*142.0*	2,267.1	*139.2*	2,251.9
Retained earnings (accumulated deficit)					
Balance, beginning of year			(15.5)		(235.1)
Net income			680.6		236.9
Dividends	10		(160.4)		(27.4)
Recognition of deferred income tax asset	13		–		9.5
Reclassification of accumulated gain on securities	7,11		12.9		0.6
Balance, end of year			517.6		(15.5)
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			370.0		65.5
Other comprehensive income			221.9		301.4
Contributed surplus			14.4		3.7
Reclassification of accumulated gain on securities	7		(12.9)		(0.6)
Balance, end of year			593.4		370.0
Total Shareholders' Equity			3,378.1		2,606.4

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-rich natural gas 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 the Company's registered office is Suite 4700, 888 – 3rd Street SW, Calgary, Alberta T2P 5C5. The consolidated group includes wholly-owned subsidiaries Fox Drilling Limited Partnership ("Fox Drilling"), Cavalier Energy Inc. ("Cavalier") and MGM Energy.

These consolidated financial statements, as at December 31, 2022 and 2021 and for the years then ended (the "Consolidated Financial Statements"), were authorized for issuance by Paramount's Board of Directors on March 6, 2023.

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. Certain comparative figures have been reclassified to conform to the current year's presentation.

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.

Paramount purchases commodities from third parties from time-to-time to fulfill sales commitments and for blending purposes. The Company sells these products to its customers. These transactions are presented as separate revenue and expense items in the consolidated statements of comprehensive income.

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.

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 drilling rigs (the "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 derecognized.

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 costs 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 three CGUs: Grande Prairie, Kaybob and Central Alberta and Other. The Company's E&E assets, consisting mainly of undeveloped land, are aggregated together into a single group 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. When an acquisition does not qualify as a business combination, the assets are measured at the fair value of the consideration paid (including any liabilities assumed) on the acquisition date.

i) 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.

j) Asset Retirement Obligations

Asset retirement obligations arise from legal and/or constructive obligations to abandon and reclaim petroleum and natural gas 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 petroleum and natural gas assets and are depleted on the same basis as the underlying assets. 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 depletion, depreciation and impairment reversals.

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 abandonment and reclamation of a property is complete.

k) Foreign Currency Translation

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

l) 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.

m) 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 certain of 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 contracts, foreign currency exchange contracts and other derivatives not accounted for as cash flow hedges 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 7 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 incorporated 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 generally 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.

In certain circumstances, financial instruments originally designated for hedge accounting may be de-designated for hedge accounting, in which case changes in their fair values over time are recognized in net earnings.

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. Cumulative changes in OCI are included in Reserves, which is presented within shareholders' equity in the consolidated balance sheet.

Compound Financial Instruments

In January 2021, the Company issued convertible debentures, all of which were converted into class A common shares of Paramount ("Common Shares") in the fourth quarter of 2021. These convertible debentures were compound financial instruments that contained both a liability and an equity component, which were initially recognized at fair value. The fair value of the liability component was 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 was 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 was classified within shareholders' equity. The liability component was carried at amortized cost and 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, was recorded as interest and financing expense. The equity component was not remeasured subsequent to initial recognition. The accreted liability and equity components of the convertible debentures were reclassified to share capital on their conversion into Common Shares in the fourth quarter of 2021.

n) 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.

o) 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.

p) 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 Cavalier 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 awards 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 Contributed Surplus. Upon vesting of awards, the related Contributed Surplus is reclassified to Share Capital.

q) 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 any convertible debentures outstanding during the period. For Paramount Options, the number of dilutive Common Shares is determined using the treasury stock method. For convertible debentures that were outstanding in 2021, net income was increased by the after-tax interest and financing expense on the convertible debentures and the number of diluted Common Shares was increased by shares issuable on conversion of the convertible debentures, when dilutive to the calculation of diluted net income per share.

r) 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.

s) Government Grants

Government grants are recognized when there is reasonable assurance that the relevant conditions of the grant are met and 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 reduction in depletion, depreciation and impairment reversals expense in the consolidated statement of comprehensive income for the year in which the related eligible costs are incurred.

t) Assets Held for Sale

The Company classifies non-current assets as held for sale if their carrying amounts will be recovered through sale instead of continuing use. This condition is met when the sale is highly probable and the assets are available for immediate sale in their present condition. For the sale to be highly probable, Management must be at least committed to a plan to sell the assets and have initiated an active program to locate a buyer. The assets must also be actively marketed for sale at a price that is reasonable in relation to their current fair value and the sale should be expected to be completed within one year from the date of classification.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and recoverable amount, with impairments or impairment reversals recognized in the consolidated statement of comprehensive income. Non-current assets classified as held for sale and their associated liabilities are presented in current assets and current liabilities within the consolidated balance sheet and are not depleted, depreciated or amortized.

2. New and Updated Accounting Policies and Standards

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, 2023. 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.

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

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.

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 regulatory, partner or other approvals 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: 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.

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.

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 credit-adjusted risk-free discount and inflation rates 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.

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.

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 fair value of the stock 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.

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.

4. Assets Held for Sale

In December 2022, Paramount entered into an agreement to sell its Kaybob Smoky and Kaybob South Duvernay properties and certain other minor interests in the Kaybob region, all of which were included in the Kaybob CGU, for gross proceeds of $375 million before customary closing adjustments. The transaction closed in January 2023.

The assets and liabilities associated with the sale have been presented as held for sale at December 31, 2022, as follows:

As at December 31	2022
Property, plant and equipment, net	**217.7**
Exploration and evaluation	**34.0**
Assets held for sale	**251.7**
Asset retirement obligations	**2.0**
Liabilities associated with assets held for sale	**2.0**

5. Exploration and Evaluation

Year ended December 31	2022	2021
Balance, beginning of year	**539.9**	612.1
Additions	**0.4**	1.3
Land acquisitions	**34.7**	8.9
Change in asset retirement provision	**(0.2)**	1.3
Transfers to property, plant and equipment	**(33.1)**	(14.0)
Expired lease costs	**(21.8)**	(29.8)
Dry hole	**–**	(1.1)
Dispositions	**(0.2)**	(38.8)
Transfer to assets held for sale (see Note 4)	**(34.0)**	–
Balance, end of year	**485.7**	539.9

Cavalier entered into a farm-out agreement with Rubellite Energy Inc. ("Rubellite") in 2022 under which Rubellite may earn up to a 60 percent working interest in 61.25 gross sections of Cavalier's Clearwater formation rights in the Peavine area of Alberta by drilling wells or making certain qualifying capital expenditures. A director and significant shareholder of Paramount is also the President and Chief Executive Officer, a director and significant shareholder of Rubellite.

Exploration and Evaluation Expense

Year ended December 31	2022	2021
Geological and geophysical expense	8.8	8.0
Dry hole expense	–	1.1
Expired lease costs	21.8	29.8
	30.6	38.9

At December 31, 2022, the Company assessed its E&E assets for indicators of potential impairment or impairment reversal and none were identified.

6. Property, Plant and Equipment

Year ended December 31, 2022	Petroleum and natural gas assets	Drilling rigs	Right-of-use assets	Other	Total
Cost					
Balance, December 31, 2021	4,317.6	167.1	16.1	50.7	4,551.5
Additions	623.5	22.0	9.0	15.0	669.5
Land and property acquisitions	116.1	–	–	–	116.1
Transfers	36.7	(3.6)	–	–	33.1
Dispositions	(9.9)	(3.9)	(0.1)	–	(13.9)
Derecognition	–	(28.6)	(0.2)	(6.2)	(35.0)
Change in asset retirement provision	(67.4)	–	–	–	(67.4)
Transfer to assets held for sale (see Note 4)	(359.3)	–	–	–	(359.3)
Cost, December 31, 2022	4,657.3	153.0	24.8	59.5	4,894.6
Accumulated depletion and depreciation					
Balance, December 31, 2021	(2,119.6)	(109.5)	(11.7)	(41.0)	(2,281.8)
Depletion and depreciation	(325.6)	(9.5)	(3.5)	(3.5)	(342.1)
Dispositions	5.3	3.6	0.1	–	9.0
Derecognition	–	28.6	0.2	6.2	35.0
Transfer to assets held for sale (see Note 4)	141.6	–	–	–	141.6
Accumulated depletion and depreciation, December 31, 2022	(2,298.3)	(86.8)	(14.9)	(38.3)	(2,438.3)
Net book value, December 31, 2021	2,198.0	57.6	4.4	9.7	2,269.7
Net book value, December 31, 2022	2,359.0	66.2	9.9	21.2	2,456.3

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)**
Impairment reversals	296.6	–	–	–	**296.6**
Dispositions	117.4	–	0.2	–	**117.6**
Accumulated depletion and depreciation, 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**

Effective January 1, 2022, Northern CGU petroleum and natural gas assets were combined with the Central Alberta CGU to form the Central Alberta and Other CGU.

In 2022, the Company closed two property acquisitions in the Willesden Green area of Alberta, which is included in the Central Alberta and Other CGU, for total cash consideration of $98.3 million. Both of these acquisitions were accounted for as asset acquisitions, with an aggregate $91.1 million being allocated to property, plant and equipment, $9.5 million allocated to exploration and evaluation assets and $2.3 million allocated to asset retirement obligations.

In October 2022, the Company closed the sale of approximately 60 kilometers of operated resources roads in the Kaybob CGU for cash proceeds of $64.2 million. A gain of $62.4 million was recognized on the sale.

In the fourth quarter of 2022, Fox Drilling permanently decommissioned two of its conventional drilling rigs. A charge of $2.6 million was recorded to depletion and depreciation expense to derecognize the carrying value of the rigs.

Paramount sold its non-operated Birch assets in northeast British Columbia in 2021, which were included in the Central Alberta and Other CGU, for proceeds of approximately $85 million. A $14.0 million reversal of previously recorded impairment charges and gain of $36.1 million was recognized in 2021 in connection with the sale.

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

Depletion, Depreciation and Impairment Reversal

Year ended December 31	2022	2021
Depletion and depreciation	335.8	300.5
Change in asset retirement obligations	(39.8)	138.9
Alberta site rehabilitation program funding	(10.0)	(9.7)
Reversals of petroleum and natural gas asset impairments	–	(296.6)
	286.0	133.1

At December 31, 2022, the Company assessed its property, plant and equipment assets for indicators of potential impairment and none were identified.

For the year ended December 31, 2022, the Company recorded a recovery of $39.8 million (December 31, 2021 – a charge of $138.9 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 were mainly due to 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 represented 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 the 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.

7. Investments in Securities

As at December 31	2022	2021
Level one fair value hierarchy securities ("Level One Securities")	477.3	300.2
Level three fair value hierarchy securities ("Level Three Securities")	79.8	71.9
	557.1	372.1

At December 31, 2022, the Company owned 37.3 million common shares of NuVista Energy Ltd. ("NuVista Shares") (December 31, 2021 – 39.8 million) having a carrying value of $464.9 million (December 31, 2021 – $276.7 million), which were included in investments in securities and classified as Level One Securities.

As a result of changes in the fair value estimates of its investments in securities, the Company recorded $235.3 million, before tax, to OCI for the year ended December 31, 2022.

In 2022, Paramount disposed of 2.5 million NuVista Shares as well as investments in other Level One and Level Three Securities for aggregate proceeds of $56.8 million, resulting in $12.9 million of accumulated net gains, net of tax, being reclassified from reserves to retained earnings.

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

Year ended December 31	2022	2021
Investments in securities, beginning of year	372.1	59.5
Changes in fair value of Level One Securities	222.4	256.0
Changes in fair value of Level Three Securities	12.9	60.8
Changes in fair value of warrants – recorded in earnings	0.4	–
Acquired – cash	1.8	1.0
Acquired – non-cash	4.3	–
Proceeds of dispositions – cash	(52.8)	(5.2)
Proceeds of dispositions – non-cash	(4.0)	–
Investments in securities, end of year	557.1	372.1

Settlement of Dissent Payment Entitlement

In June 2021, Paramount received $67 million cash in settlement of dissent proceedings with respect to one of its prior investments. A loss of $22.6 million was recognized in 2021 on the settlement.

8. Long-Term Debt

As at December 31	2022	2021
Paramount Facility (1)	159.4	386.3

(1) Presented net of $2.4 million in unamortized transaction costs (December 31, 2021 – $2.8 million).

Paramount Facility

The Company has a $1.0 billion financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility"). The maturity date of the Paramount Facility is May 3, 2026. At Paramount's request, the credit limit of the Paramount Facility can be increased by up to $250 million 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, Canadian Dollar Offered Rates or Adjusted Term SOFR, 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 also 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, 2022.

The Company had undrawn letters of credit outstanding under the Paramount Facility totaling $2.2 million at December 31, 2022 (December 31, 2021 – $2.3 million) 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. The PSG is valid to June 30, 2023. At December 31, 2022, $24.2 million in undrawn letters of credit were outstanding under the LC Facility (December 31, 2021 – $38.7 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 at any time prior to the Maturity Date, were convertible by the holder into Common Shares and redeemable by Paramount.

In November 2021, Paramount delivered notices to redeem all $35.0 million of the Convertible Debentures at a redemption price of 107.50 percent of the principal amount 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 5.2 million 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, 2022	**Current**	**Long-term**	**Total**
Asset retirement obligations	37.7	502.4	**540.1**
Lease liabilities	3.0	15.0	**18.0**
Asset retirement obligations and other	**40.7**	**517.4**	**558.1**

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**

Asset Retirement Obligations

Year ended December 31	**2022**	**2021**
Asset retirement obligations, beginning of year	**651.1**	419.5
Additions	**4.7**	1.3
Change in estimates	**(16.3)**	23.8
Change in discount rate	**(95.7)**	206.4
Obligations settled – cash	**(36.1)**	(25.4)
Obligations settled – funding under Alberta site rehabilitation program	**(10.0)**	(9.7)
Dispositions	**(0.5)**	(7.4)
Transfer to liabilities associated with assets held for sale (see Note 4)	**(2.0)**	–
Accretion expense	**44.9**	42.6
Asset retirement obligations, end of year	**540.1**	651.1

As at December 31, 2022, estimated undiscounted, uninflated asset retirement obligations were $1,296.0 million (December 31, 2021 – $1,318.7 million). Asset retirement obligations have been determined using a credit-adjusted risk-free discount rate of 8.5 percent per annum (December 31, 2021 – 7.0 percent per annum) and an inflation rate of 2.0 percent per annum (December 31, 2021 – 2.0 percent per annum). 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. A weighted average incremental borrowing rate of approximately 5.6 percent was used to determine the discounted amount of the liabilities in 2022 (2021 – 5.4 percent). For the year ended December 31, 2022, total cash payments made in respect of these lease liabilities, net of sublease arrangements, were $7.6 million, (2021 – $8.4 million) of which $0.3 million (December 31, 2021 – $0.7 million) was recognized in interest and financing expense.

For the year ended December 31, 2022, 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 (2021 – $2.5 million).

At December 31, 2022, $0.4 million (December 31, 2021 – $2.7 million) was receivable by the Company in respect of sublease arrangements for Paramount's office space, of which $0.4 million (December 31, 2021 – $2.2 million) was classified as current and $nil (December 31, 2021 – $0.5 million) was classified as non-current. For the year ended December 31, 2022, $2.3 million (2021 – $2.6 million) was received in respect of office sublease arrangements, of which $0.1 million (2021 – $0.2 million) was recognized in interest revenue.

In 2022, Paramount recognized a lease liability of $14.0 million and a lease incentive receivable of $6.3 million related to a new 14 year lease.

At December 31, 2022, the undiscounted minimum cash lease payments payable by the Company under lease arrangements and receivable amounts due to the Company in respect of sublease arrangements are as follows:

	Lease Payments	Sublease Receivables
Within one year	2.9	0.4
After one year but not more than five years	7.5	–
More than five years	15.3	–
	25.7	0.4

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, 2022, 142.0 million (December 31, 2021 – 139.2 million) Common Shares were outstanding, net of 0.8 million (December 31, 2021 – 1.5 million) Common Shares held in trust under the RSU plan and no preferred shares were outstanding.

In July 2021, Paramount implemented a regular monthly dividend with respect to its Common Shares. Dividends paid for the year ended December 31, 2022 totaled $160.4 million (2021 – $27.4 million) or $1.13 per Common Share (2021 – $0.20 per Common Share). Subsequent to December 31, 2022, the Company declared and paid a special cash dividend of $1.00 per Common Share totaling $142.9 million and two months of regular monthly dividends totaling $0.25 per Common Share or $35.7 million.

In June 2022, Paramount implemented a normal course issuer bid (the "2022 NCIB") under which the Company may purchase up to 7.6 million Common Shares for cancellation. The 2022 NCIB will terminate on the earlier of June 29, 2023 and the date on which the maximum number of Common Shares that can be acquired pursuant to the 2022 NCIB are purchased. Purchases of Common Shares under the NCIB will be effected through the facilities of the Toronto Stock Exchange or alternative Canadian trading systems at the market price at the time of purchase. The Company has not made any purchases of Common Shares under the 2022 NCIB to date.

Paramount previously implemented a normal course issuer bid in June 2021 (the "2021 NCIB") under which the Company purchased and cancelled 197,500 Common Shares at a total cost of $2.7 million ($13.69 per share). The 2021 NCIB expired on June 29, 2022.

For the year ended December 31, 2022, Paramount issued 2.1 million Common Shares on the exercise of Paramount Options (see Note 12).

Weighted Average Common Shares and Diluted Net Income

Year ended December 31	2022		2021	
	Wtd. Avg. Shares (millions)	**Net income**	*Wtd. Avg. Shares (millions)*	Net income
Net income – basic	***140.8***	**680.6**	*133.6*	236.9
Dilutive effect of Convertible Debentures	**–**	**–**	*4.8*	2.2
Dilutive effect of Paramount Options	***6.2***	**–**	*4.4*	–
Net income – diluted	***147.0***	**680.6**	*142.8*	239.1

Paramount Options and Convertible Debentures that can be exchanged for Common Shares are potentially dilutive and are included in the diluted per share calculations when they are dilutive to net income per share. Common Shares held in trust under the RSU plan are not included in the calculation of weighted average shares outstanding.

For the year ended December 31, 2022, 2.5 million Paramount Options were anti-dilutive (2021 – 3.8 million).

11. Reserves

Reserves at December 31, 2022 include unrealized gains and 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.

The changes in reserves are as follows:

Year ended December 31, 2022	Unrealized gains (losses) on cash flow hedges	Unrealized gains (losses) on securities	Contributed surplus	Total reserves
Balance, beginning of year	(5.3)	204.5	170.8	**370.0**
Other comprehensive income, before tax	17.8	235.3	–	**253.1**
Deferred tax	(4.2)	(27.0)	–	**(31.2)**
Reclassification of accumulated gain on securities, net of tax (see Note 7)	–	(12.9)	–	**(12.9)**
Share-based compensation (see Note 12)	–	–	21.1	**21.1**
Paramount Options exercised	–	–	(6.7)	**(6.7)**
Balance, end of year	**8.3**	**399.9**	**185.2**	**593.4**

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**

12. Share-Based Compensation

Paramount Options

	2022		2021	
	Paramount Options (millions)	Weighted average exercise price ($/share)	*Paramount Options (millions)*	Weighted average exercise price ($/share)
Balance, beginning of year	***11.0***	**9.55**	*9.7*	6.91
Granted	***2.5***	**28.65**	*3.2*	16.31
Exercised [(1)]	***(2.1)***	**10.73**	*(1.5)*	7.03
Cancelled or forfeited	***(0.1)***	**10.90**	*(0.3)*	8.49
Expired	***–***	**–**	*(0.1)*	15.97
Balance, end of year	***11.3***	**13.55**	*11.0*	9.55
Options exercisable, end of year	***3.1***	**8.28**	*2.7*	9.23

(1) For Paramount Options exercised during the year ended December 31, 2022, the weighted average market price of Common Shares on the dates exercised was $30.12 per share (2021 – $17.05 per share).

The weighted average remaining contractual life and exercise prices of Paramount Options outstanding as at December 31, 2022 are as follows:

	Paramount Options Outstanding			Paramount Options Exercisable		
Exercise Price	**Number *(millions)***	**Remaining contractual life *(years)***	**Weighted average exercise price**	**Number *(millions)***	**Remaining contractual life *(years)***	**Weighted average exercise price**
$1.64 – $6.99	3.6	3.0	4.56	1.1	3.0	4.70
$7.00 – $15.99	2.3	1.8	7.42	1.4	1.8	7.39
$16.00 – $23.99	2.9	4.3	16.31	0.6	3.9	16.63
$24.00 – $36.12	2.5	5.3	28.61	–	4.3	30.23
	11.3	**3.6**	**13.55**	**3.1**	2.6	**8.28**

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 2022	**Options awarded in 2021**
Weighted average exercise price ($ / share)	**28.65**	16.31
Volatility (%)	**45**	44
Expected life of share options (years)	**3.9**	4.3
Pre-vest annual forfeiture rate (%)	**11.5**	12.9
Risk-free interest rate (%)	**3.1**	0.8
Dividend yield (%)	**5.3**	1.5
Weighted average fair value of awards per option ($ / option)	**7.19**	5.18

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 vested over five years and expire in September 2024. As at December 31, 2022, there were 3.7 million Cavalier Options outstanding and no Cavalier Options have been exercised.

Restricted Share Unit Plan – Shares Held in Trust

	2022		2021	
Year ended December 31	***Shares (millions)***		***Shares (millions)***	
Balance, beginning of year	***1.5***	**3.5**	*1.9*	1.5
Shares purchased	***0.5***	**17.2**	*1.1*	10.8
Change in vested and unvested shares	***(1.2)***	**(4.5)**	*(1.5)*	(8.8)
Balance, end of year	***0.8***	**16.2**	*1.5*	3.5

Employee Benefit Costs

Year ended December 31	2022	2021
Stock option plans	8.4	6.8
RSU plan	16.9	12.0
Share-based compensation expense	25.3	18.8
Salaries and benefits	55.6	52.6
	80.9	71.4

13. Income Tax

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

Year ended December 31	2022	2021
Income before tax	865.8	322.5
Effective statutory income tax rate (1)	23.0%	23.1%
Expected income tax expense	199.1	74.5
Effect on income taxes of:		
Change in statutory and other rates	1.0	2.2
Share-based compensation	1.9	1.6
Gain on sale of oil and gas assets	(6.5)	(0.1)
Settlement of dissent payment entitlement	–	2.6
Change in unrecognized deferred income tax asset	(9.5)	0.5
Non-deductible items and other	(0.8)	4.3
Income tax expense	185.2	85.6

(1) Combined federal and provincial statutory tax rates for the Company. The change in the effective statutory income tax rate results from variations in income by province.

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

As at December 31	2022	2021
Property, plant and equipment	(409.4)	(412.8)
Investments in securities	(52.5)	(32.5)
Asset retirement obligations	124.2	149.4
Non-capital losses and scientific research & experimental development	665.3	821.4
Other	1.5	20.0
Deferred income tax asset	329.1	545.5

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

Year ended December 31	2022	2021
Deferred income tax asset, beginning of year	545.5	658.8
Deferred income tax expense	(185.2)	(85.6)
Deferred income tax expense included in OCI	(31.2)	(37.1)
Deferred income tax recovery recognized in accumulated deficit	–	9.5
Other	–	(0.1)
Deferred income tax asset, end of year	329.1	545.5

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.

The Company has $154.1 million (December 31, 2021 – $151.3 million) of deductible temporary differences and unused tax losses that expire between 2029 and 2042 for which no deferred income tax asset has been recorded.

14. Financial Instruments and Risk Management

Financial Instruments

Financial instruments at December 31, 2022 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 risk management assets and liabilities for the year ended December 31, 2022 are as follows:

Year ended December 31, 2022	Financial commodity contracts	Foreign currency exchange contracts	Interest rate swaps	Electricity swaps	Total
Fair value of asset (liability), December 31, 2021	5.4	0.4	(9.6)	0.7	(3.1)
Changes in fair value – profit or loss (1)	(160.1)	(22.7)	5.0	–	(177.8)
Changes in fair value – OCI	–	–	12.9	10.1	23.0
Risk management contract settlements paid (received) (2)	166.5	12.5	(8.3)	–	170.7
Fair value of asset (liability), December 31, 2022	11.8	(9.8)	–	10.8	12.8
Risk management asset – current	11.8	–	–	7.9	19.7
Risk management asset – long-term	–	–	–	2.9	2.9
Risk management asset, December 31, 2022	11.8	–	–	10.8	22.6
Risk management liability – current	–	(9.8)	–	–	(9.8)
Risk management liability, December 31, 2022	–	(9.8)	–	–	(9.8)

(1) Changes in fair value of ($182.8) million related to financial commodity and foreign currency exchange contracts are recorded as loss on risk management contracts. Changes in fair value of $5.0 million related to interest rate swaps not accounted for as cash flow hedges are recorded in interest and financing expense.

(2) Payments on risk management contract settlements related to financial commodity and foreign currency exchange contracts totaled $179.0 million. Risk management contract settlements relating to interest rate swap and electricity swap contracts, where hedge accounting is applied, are recorded in interest and financing and operating expense, respectively.

Changes in the fair value of risk management assets and liabilities 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 paid (received) (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 related to financial commodity and foreign currency exchange contracts are recorded as loss on risk management contracts. Changes in fair value of ($1.9) million related to interest rate swaps not accounted for as cash flow hedges are recorded in interest and financing expense.
(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, where hedge accounting is applied, are recorded in interest and financing and operating expense, respectively.

The Company had the following risk management contracts as at December 31, 2022:

Instruments	Aggregate amount / notional	Average price or rate	Remaining term
Financial Commodity Contracts (1)			
Natural Gas			
NYMEX Collars	20,000 MMBtu/d	US$7.50/MMBtu (Floor) US$12.13/MMBtu (Ceiling)	January 2023 – March 2023
AECO Collars	20,000 GJ/d	CAD$7.25/GJ (Floor) CAD$9.60/GJ (Ceiling)	January 2023 – March 2023
Chicago Index Swap (Sale) (2)	5,000 MMBtu/d	Daily – US$0.09/MMBtu	January 2023 – March 2023
Foreign Currency Exchange Contracts			
Forwards and Swaps	US$40 million / month	1.2953 CAD$/US$1.00	January 2023 – March 2023
Forwards	US$20 million / month	1.3025 CAD$/US$1.00	April 2023 – June 2023
Electricity Contracts (3)			
Swaps	240 MWh/d (4)	$84.00/MWh	January 2023 – December 2023
Swaps	240 MWh/d (4)	$66.13/MWh	January 2024 – December 2024
Swaps	120 MWh/d (4)	$73.25/MWh	January 2025 – December 2025

(1) "NYMEX" means New York Mercantile Exchange.
(2) "Chicago Index" refers to Chicago Citygate Index pricing. These contracts convert price exposure of Chicago monthly index to daily index.
(3) Reference electricity rate: Floating hourly rate established by the Alberta Electric System Operator.
(4) "MWh" means megawatt-hour.

Subsequent to December 31, 2022, the Company entered into the following foreign currency exchange contracts:

Instruments	Aggregate amount / notional	Average price or rate	Remaining term
Swaps	US$20 million / month	1.3375 CAD$/US$1.00	February 2023 – December 2023
Swaps	US$20 million / month	1.3479 CAD$/US$1.00	March 2023 – December 2023
Swaps	US$30 million / month	1.3433 CAD$/US$1.00	January 2024 – June 2024
Swaps	US$10 million / month	1.3400 CAD$/US$1.00	July 2024 – December 2024

In December 2022, Paramount terminated all $500 million notional amount of its floating-to-fixed interest rate swaps for aggregate cash proceeds to the Company of $10.3 million. For the year ended December 31, 2022, interest and financing expense was reduced by $10.2 million relating to the impact of floating-to-fixed interest rate swaps.

In 2022, the Company entered into floating-to-fixed price swaps on 120 MWh/d of electricity, which were designated as cash flow hedges, to manage exposure to variable market prices by fixing the underlying AESO Pool Price on a portion of the Company's anticipated power requirements for 2023, 2024 and 2025 (2021 – floating-to-fixed electricity price swaps on 120 MWh/d of electricity for 2023 and 2024).

The Company has classified its electricity swaps as cash flow hedges and applied hedge accounting. There were no changes to the critical terms of the hedging relationships and no hedge ineffectiveness was identified on the floating-to-fixed electricity swaps.

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, 2022 to independent fluctuations in commodity prices, with all other variables held constant. The impact of fluctuating commodity prices on the Company’s December 31, 2022 open financial commodity contract positions would have resulted in an unrealized gain (loss) impacting income before income tax as follows: [(1)]

	Increase in Commodity Price	Decrease in Commodity Price
	NYMEX Henry Hub	NYMEX Henry Hub
Income before income tax	(1.6)	1.6

(1) Sensitivities are based on 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 foreign currency exchange contracts, U.S. dollar denominated and other financial instruments outstanding at December 31, 2022 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, 2022 open foreign currency exchange contracts, U.S. dollar denominated and other financial instruments would have resulted in an unrealized gain (loss) impacting income before income tax as follows: [(1)]

	Increase in C$/US$ Foreign Currency Exchange Rate	Decrease in C$/US$ Foreign Currency Exchange Rate
Income before income tax	(6.7)	6.7

(1) Sensitivities are based on a C$0.05 increase or decrease in C$/US$ foreign currency exchange rates at December 31, 2022, 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, 2022 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 credit and other financial risks and to maintain adequate levels of liquidity. The Company's risk management contracts 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, 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.

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)]

	2023	2024	2025	2026	Total
Accounts payable & accrued liabilities	229.9	–	–	–	229.9
Paramount Facility	–	–	–	161.8	161.8
	229.9	–	–	161.8	391.7

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

Accounts Payable and Accrued Liabilities

As at December 31	2022	2021
Trade and accrued payables	222.8	209.9
Joint operation and other payables	7.1	9.2
	229.9	219.1

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	2022	2021
Revenue receivable	202.2	118.1
Joint operation and other receivables	21.0	23.8
	223.2	141.9

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 1 percent as at December 31, 2022 (December 31, 2021 – 3 percent).

For the year ended December 31, 2022, the Company had sales to one customer totaling $487.7 million, which exceeded ten percent of total sales. The customer has an investment grade credit rating.

15. Revenue By Product

Year ended December 31	2022	2021
Natural gas	671.1	373.3
Condensate and oil	1,448.9	926.5
Other natural gas liquids	114.2	78.6
Royalty and other	18.2	5.2
Royalties	(335.3)	(127.0)
Sales of commodities purchased	272.0	75.5
	2,189.1	1,332.1

Royalty and other revenue for the year ended December 31, 2022 includes $11.9 million related to the Company's business interruption insurance claim arising from outages that occurred at a third-party natural gas processing facility in 2020 and 2021.

16. Other

Year ended December 31	2022	2021
Provisions	(21.9)	24.0
Settlements	–	(7.0)
Other	(5.6)	(0.8)
	(27.5)	16.2

Provisions

The Company recorded provisions of $24.0 million in 2021 and $1.6 million in the second quarter of 2022 with respect to arrangements with a service provider. Paramount had unsettled claims against the same service provider with respect to certain related matters which were not recognized in the Consolidated Financial Statements.

The Company reached an agreement with the service provider with respect to these arrangements and certain related matters, resulting in a recovery of $24.0 million being recorded to provisions in the fourth quarter of 2022.

Settlements

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

17. Consolidated Statement of Cash Flows – Selected Information

Items Not Involving Cash

Year ended December 31	2022	2021
Risk management contracts	3.7	(28.5)
Share-based compensation	25.3	18.8
Depletion, depreciation and impairment reversals	286.0	133.1
Exploration and evaluation	21.8	30.9
Gain on sale of oil and gas assets	(65.6)	(72.1)
Accretion of asset retirement obligations	44.9	42.6
Settlement of dissent payment entitlement	–	22.6
Deferred income tax	185.2	85.6
Other	2.2	4.9
	503.5	237.9

Supplemental Cash Flow Information

Year ended December 31	2022	2021
Interest paid (1)	2.1	36.7

(1) Interest paid in 2022 is net of $7.8 million received on settlement of interest rate swaps. Interest paid in 2021 includes $9.7 million paid on settlement of interest rate swaps.

Components of Cash and Cash Equivalents

As at December 31	2022	2021
Cash	2.5	1.7
Cash equivalents	–	–
	2.5	1.7

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	2022	2021
Cash and cash equivalents	(2.5)	(1.7)
Accounts receivable [(1)]	(216.5)	(139.7)
Prepaid expenses and other	(9.1)	(7.3)
Accounts payable and accrued liabilities	229.9	219.1
Long-term debt	159.4	386.3
Net Debt	161.2	456.7

(1) Excludes accounts receivable relating to lease incentives and subleases (December 31, 2022 – $6.7 million, December 31, 2021 – $2.2 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	2022	2021
Cash from operating activities	**1,049.6**	482.1
Change in non-cash working capital	**98.4**	(32.7)
Geological and geophysical expense	**8.8**	8.0
Asset retirement obligations settled	**36.1**	25.4
Closure costs	**–**	–
Provisions	**(21.9)**	24.0
Settlements	**–**	(7.0)
Transaction and reorganization costs	**–**	–
Adjusted funds flow	**1,171.0**	499.8

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.

	2022	2021
Net debt, as at December 31	**161.2**	456.7
Adjusted funds flow, trailing four quarters ended December 31	**1,171.0**	499.8
Net debt to adjusted funds flow ratio, December 31	**0.1x**	0.9x

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	2022	2021
Cash from operating activities	**1,049.6**	482.1
Change in non-cash working capital	**98.4**	(32.7)
Geological and geophysical expense	**8.8**	8.0
Asset retirement obligations settled	**36.1**	25.4
Closure costs	**–**	–
Provisions	**(21.9)**	24.0
Settlements	**–**	(7.0)
Transaction and reorganization costs	**–**	–
Adjusted funds flow	**1,171.0**	499.8
Capital expenditures	**(655.0)**	(274.6)
Geological and geophysical expense	**(8.8)**	(8.0)
Asset retirement obligations settled	**(36.1)**	(25.4)
Free cash flow	**471.1**	191.8

19. Compensation of Key Management Personnel

Year ended December 31	2022	2021
Salaries and benefits	**2.9**	1.9
Share-based compensation	**7.6**	3.8
	10.5	5.7

20. Commitments and Contingencies

Paramount had the following commitments as at December 31, 2022:

	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)	242.9	891.9	828.0
Other commitments (2)	15.8	19.8	9.4
	258.7	**911.7**	**837.4**

(1) Certain of the transportation and processing commitments are secured by outstanding letters of credit totaling $0.7 million at December 31, 2022 (December 31, 2021 – $13.0 million).
(2) Includes commitments of $13.8 million relating to new leases expected to commence in 2023.

Commitments – Physical Sales Contracts

The Company had the following basis differential physical sales contracts at December 31, 2022:

	Volume	Location	Average price	Remaining term
Condensate	5,244 Bbl/d	FSPL (1)	WTI + US$0.50/Bbl	January 2023 – March 2023
Peace sweet crude oil	3,103 Bbl/d	Peace (2)	WTI – US$3.73/Bbl	January 2023 – December 2023

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

Subsequent to December 31, 2022, the Company entered into the following basis differential physical sales contracts:

	Volume	Location	Average price	Remaining term
Natural gas	20,000 MMBtu/d	AECO	NYMEX – US$0.94/MMBtu [(1)]	April 2023 – October 2023
Natural gas	10,000 MMBtu/d	Dawn	NYMEX – US$0.19/MMBtu [(1)]	April 2023 – October 2023

(1) "NYMEX" refers to NYMEX pricing at Henry Hub.

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 government authorities. All tax and royalty filings are subject to subsequent government audit and potential reassessments. Accordingly, the final amounts may differ materially from amounts estimated and recorded.

CORPORATE INFORMATION

EXECUTIVE OFFICERS

J. H. T. Riddell
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
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R. M. MacDonald (1) (3) (4)
Independent Businessman
Oakville, Ontario

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

S. L. Riddell Rose
President and Chief Executive Officer
Perpetual Energy Inc.
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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AUDITORS

Ernst & Young LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
(“POU”)