Corporate Presentation

November 2023

Advisories

- In the interest of providing information regarding Paramount Resources Ltd. ("Paramount", "PRL" or the "Company") and its future plans and operations, this presentation contains certain forward-looking information and statements. The projections, estimates and forecasts contained in such forward-looking information and statements necessarily involve a number of assumptions and are subject to both known and unknown risks and uncertainties that may cause the Company's actual performance and financial results in future periods to differ materially from these projections, estimates and forecasts. The Advisories Appendix attached hereto lists some of the material assumptions, risks and uncertainties that these projections, estimates and forecasts are based on and are subject to. Readers are encouraged to carefully review the Advisories Appendix.
- All dollar amounts in this presentation are expressed in Canadian dollars, unless otherwise noted.
- Reserves and production information are presented in accordance with Canadian standards.
- The Advisories Appendix attached hereto contains additional information concerning the oil and gas measures and terms, reserves data and non-GAAP financial measures and other specified financial measures contained in this presentation.
- The forward-looking information and statements contained in this presentation are made effective as of November 1, 2023. Certain internally estimated play data contained in this presentation was prepared effective November 1, 2023. In each case, events or information subsequent to the applicable effective dates have not been incorporated.
- This presentation includes references to sales volumes of "natural gas", "condensate and oil", "NGLs", "other NGLs" and "Liquids". "Natural gas" refers to shale gas and conventional natural gas combined. "Condensate and oil" refers to condensate, light and medium crude oil, tight oil and heavy crude oil combined. "NGLs" refers to condensate and other NGLs combined. "Other NGLs" refers to ethane, propane and butane combined. "Liquids" refers to condensate and oil and other NGLs combined. Readers are referred to the Product Type Information section of the Advisories Appendix for more information about sales volumes by the specific product types of shale gas, conventional natural gas, NGLs, light and medium crude oil, tight oil and heavy crude oil.

Corporate Overview

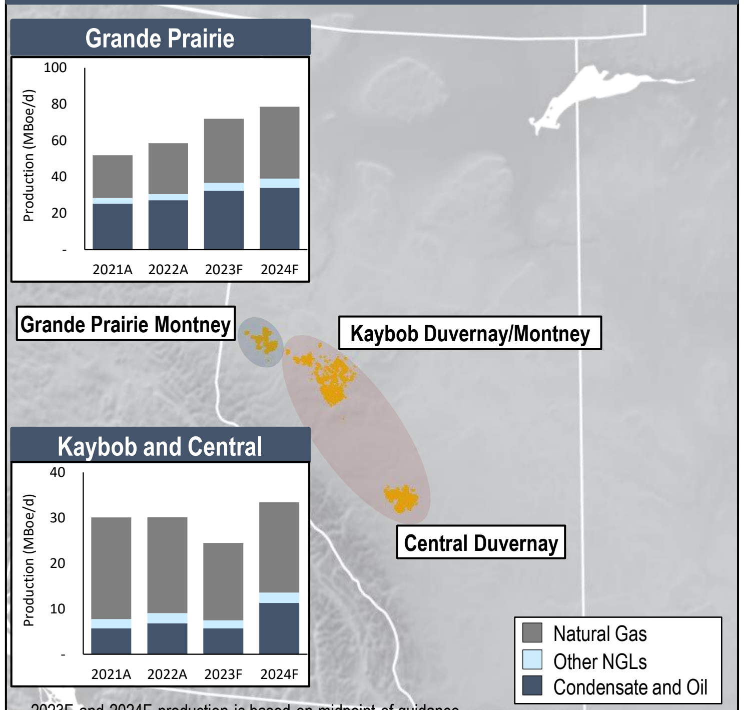
Paramount has significant land positions in the most liquids-rich areas of the prolific Montney and Duvernay resource plays

- Founded in 1976 (IPO'd in 1978)
- Significant insider ownership (~46%) [1]
- Total Proved Reserves: 445 MMBoe (49% liquids) [2]
  - NPV_{10} ~$5.8 Bn ($41.18 / basic share)
- Proved + Probable Reserves: 759 MMBoe (50% liquids) [2]
  - NPV_{10} ~$9.1 Bn ($64.52 / basic share)
- 3Q23 Production: 98,644 Boe/d (45% liquids)

Market Snapshot (TSX-POU)	
Shares Outstanding (MM)	144.3
Market Capitalization ($MM) [3]	~$4,800
Bank Debt at September 30, 2023 ($MM)	$0
Cash and Cash Equivalents at Sep. 30, 2023 ($MM)	~$45
Investments in Securities at Sep. 30, 2023 ($MM)	~$580
Monthly Dividend ($/share | Annualized Yield) [4]	$0.125 | 4.5%

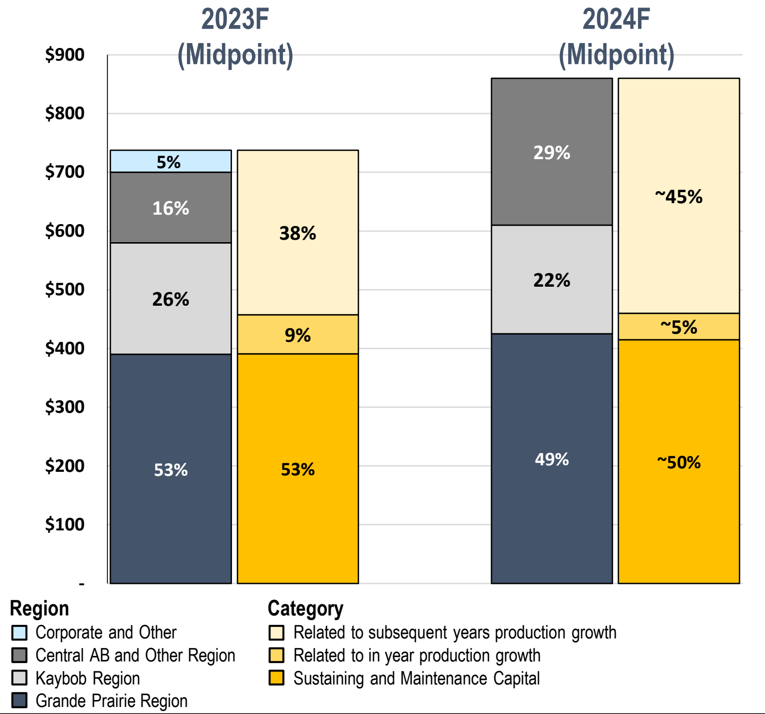
Guidance Summary [5]	2023F	2024F
Sales volumes (MBoe/d) (% Liquids)	95-98 (46%)	108-116 (47%)
CapEx ($MM)	$725-$750 *(~50% to growth)*	$830-$890 *(~50% to growth)*
ARO ($MM)	$55	$40
Mid-point FCF ($MM) [6]	~$165	~$350
Annualized base dividend ($MM) [7]	~$215	~$215

Focus Areas

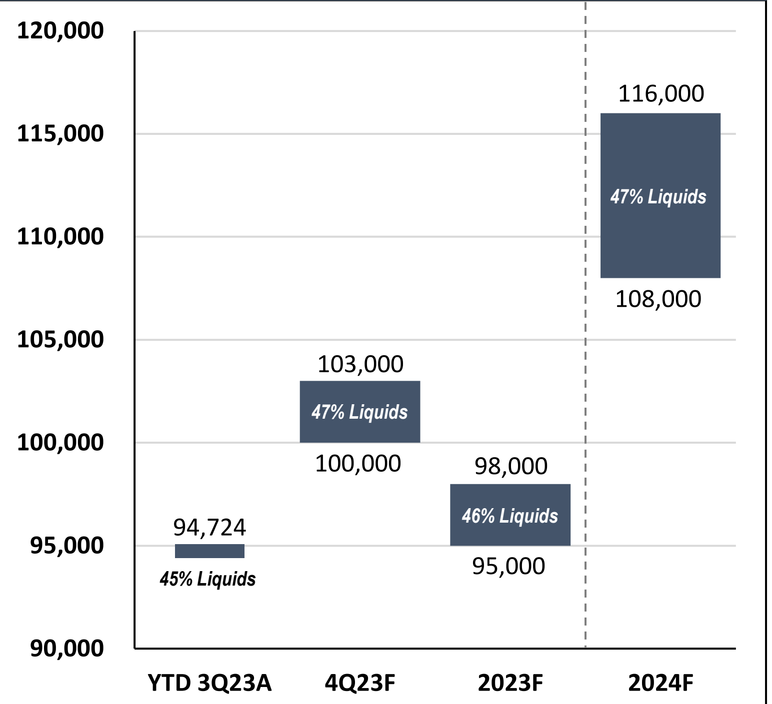


2023F and 2024F production is based on midpoint of guidance

Capital Expenditure Outlook ($MM)



Production Outlook Range (Boe/d)



(1) Consists of class A common shares ("Common Shares") held by directors, officers and other insiders. (2) 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"). "NPV10" 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. See Advisories Appendix – Reserves Data. (3) 144.3MM Common Shares at $33.56/share. (4) Annualized yield is obtained by dividing 12 months of the stated monthly dividend by a Common Share price of $33.56. (5) See Advisories Appendix – Forward Looking Information for a breakdown of the pricing, cost, expenditure and other assumptions for the last quarter of 2023 and annual 2024 on which the estimates are based. (6) FCF means free cash flow. Free cash flow is a capital management measure used by Paramount. See Advisories Appendix – Specified Financial Measures. (7) Based on current monthly dividend of $0.125 per share and current shares outstanding.

Delivering on Free Cash Flow Priorities

With an undrawn $1.0 billion credit facility at quarter end, Paramount is well positioned to deliver on its FCF priorities

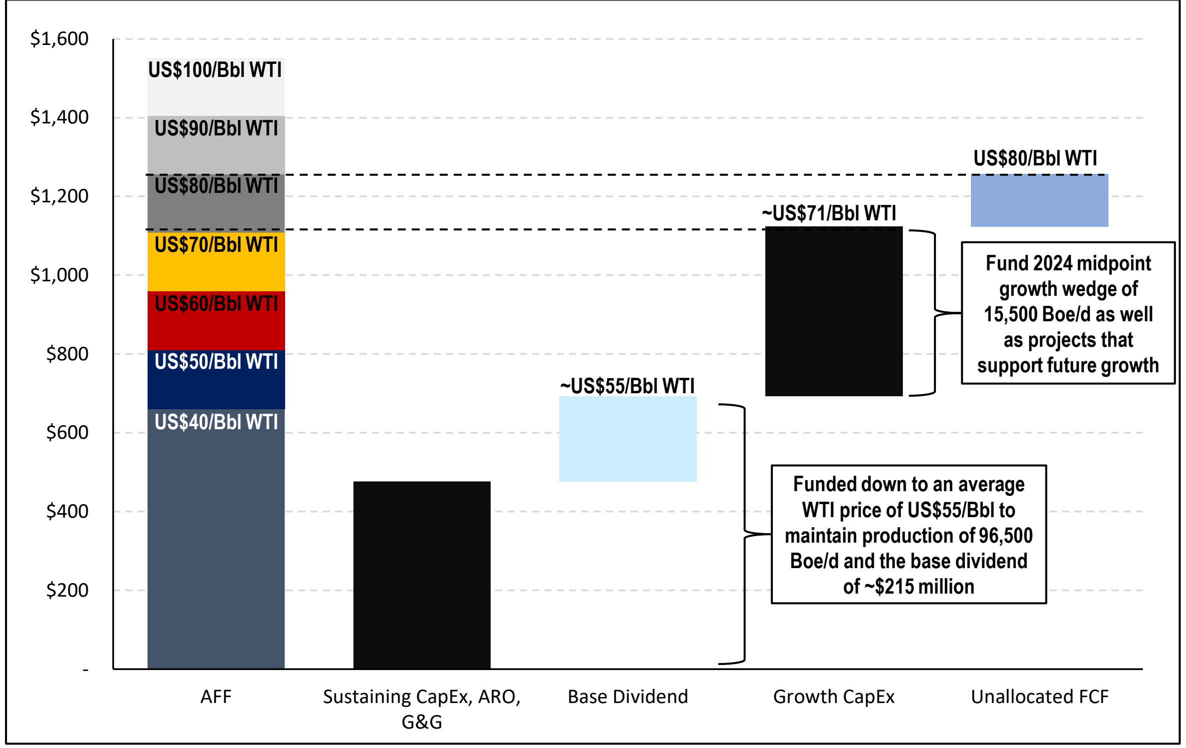
- Paramount's free cash flow priorities continue to be the maintenance of conservative leverage levels and the delivery of attractive shareholder returns through a combination of:
  - Dividends, including the flexibility for incremental returns through further special dividends
  - Investments in growth opportunities
  - Opportunistic share buybacks
- Cumulative $3.58/share (~$510MM) cash dividends from Jul. 2021 to Oct. 2023
  - Increased monthly base dividend four times since inception
  - Special cash dividend of $1.00/share in January 2023

Guidance (1)(2)

		2023F	2024F
Midpoint of Sales Volumes Guidance	*(MBoe/d)*	*96.5*	*112*
FCF Guidance	*($MM)*	~$165	~$350
Midpoint of CapEx Guidance	*($MM)*	~$738	~$860
ARO Guidance	*($MM)*	~$55	~$40
Geological & Geophysical Expense ("G&G")	*($MM)*	~$7	~$7
Illustrative Adjusted Funds Flow ("AFF")	*($MM)*	**~$965**	**~$1,255**

- Paramount's midpoint 2024 sustaining and maintenance capital program and regular monthly dividend would remain fully funded down to an average WTI price of about US$55/Bbl (3)
- The Company's total midpoint 2024 capital program and regular monthly dividend would remain fully funded down to an average WTI price of about US$71/Bbl (3)

Illustrative 2024 AFF Estimates ($MM) (1)(2)



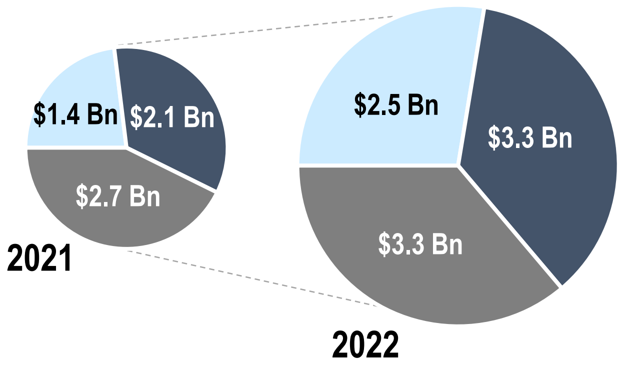
(1) See Advisories Appendix – Forward Looking Information for a breakdown of the pricing, cost, expenditure and other assumptions for the last quarter of 2023 and annual 2024 on which the estimates are based. **(2)** Free cash flow and adjusted funds flow are capital management measures used by Paramount. See Advisories Appendix – Specified Financial Measures. **(3)** Assuming no changes to the other forecast assumptions for 2024.

Reserves

Strong recycle ratios that generate material free cash flows

Reserves Growth(1)

Value ($Bn NPV$_{10}$)

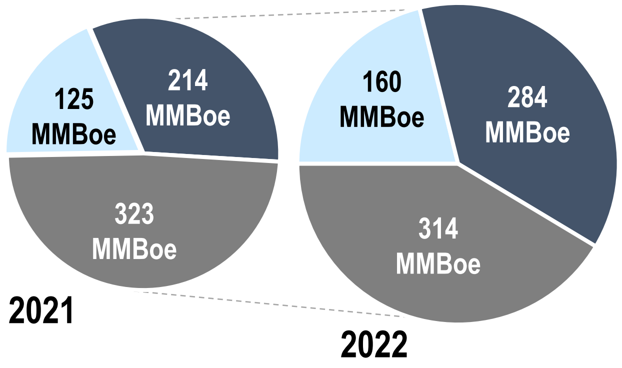


PDP	$2.5 Bn (+75%)	($17.82/sh.)
TP	$5.8 Bn (+62%)	($41.18/sh.)
P+P	$9.1 Bn (+46%)	($64.52/sh.)

Percentages represent year-over-year growth

PDP
PUD
Probable

Volumes (MMBoe)



PDP	160 MMBoe (+28%)
TP	445 MMBoe (+31%)
P+P	759 MMBoe (+15%)

Percentages represent year-over-year growth

PDP
PUD
Probable

	2022 (2)				Three-Year Average (2)			
	F&D ($/Boe)		Recycle Ratio (x)		F&D ($/Boe)		Recycle Ratio (x)	
	Total	Grande Prairie	Total	Grande Prairie	Total	Grande Prairie	Total	Grande Prairie
PDP	$9.58	$9.61	4.5x	5.1x	$8.13	$8.44	3.4x	4.1x
TP	$14.11	$9.95	3.0x	4.9x	$7.72	$3.73	3.5x	9.4x
P+P	$14.87	$11.82	2.9x	4.2x	$4.42	nmf (3)	6.5x	nmf (3)

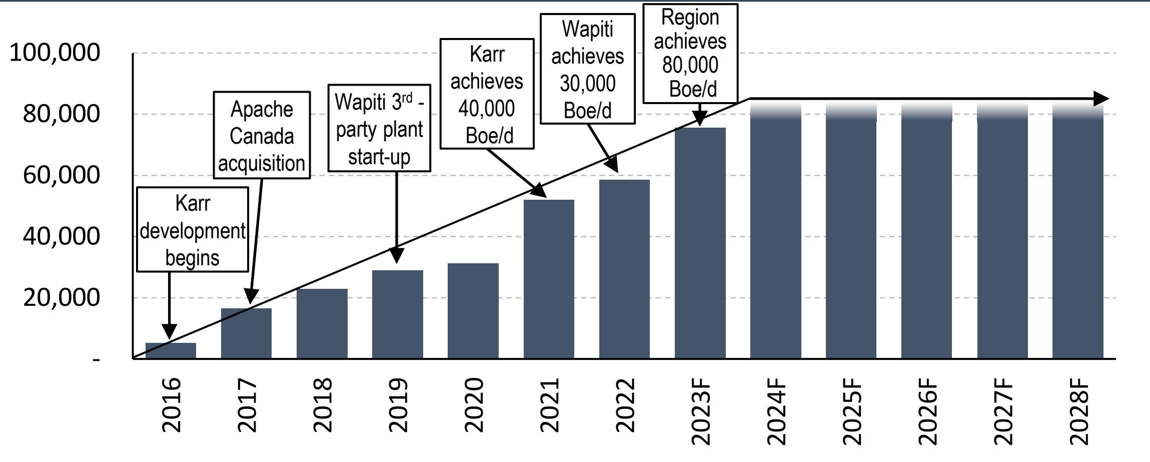
- In Grande Prairie, where the majority of 2022 development activity occurred, PDP, TP and P+P reserves volumes were up 33%, 35% and 10%, respectively
- With the significant reserves additions in 2022, the Company's reserves replacement ratios were 1.9x for PDP reserves, 4.0x for TP reserves and 3.7x for P+P reserves. (4)
- Significant factors leading to the increase in 2022 P+P reserves:
  - acceleration of development plans in the Grande Prairie Region to a higher combined production plateau
  - the advancement of the Willesden Green Duvernay development
  - further advancement of the Kaybob North Duvernay development, including increased well density

(1) Gross reserves evaluated by McDaniel as of December 31, 2022 and December 31, 2021. "NPV10" refers to the net present value of future net revenue of the applicable reserves, discounted at 10 percent as estimated by McDaniel. Net present values of future net revenue do not represent fair market value. "PDP" means proved developed producing. "TP" means total proved. "P+P" means proved plus probable. "PUD" means proved undeveloped. See Advisories Appendix – Reserves Data. Per share amounts are calculated based on the number of Common Shares outstanding on March 6, 2023. **(2)** F&D costs and recycle ratio are non-GAAP ratios. Refer to "Specified Financial Measures" and "Oil and Gas Measures and Definitions" in the Advisories Appendix for more information on these measures and the related non-GAAP financial measure of F&D Capital. **(3)** Three-year average Grande Prairie F&D cost and recycle ratios are not meaningful since F&D capital (including change in future development cost) is negative. **(4)** See "Oil and Gas Measures and Definitions" in the Advisories Appendix of this document for a description of the calculation and use of reserves replacement ratio.

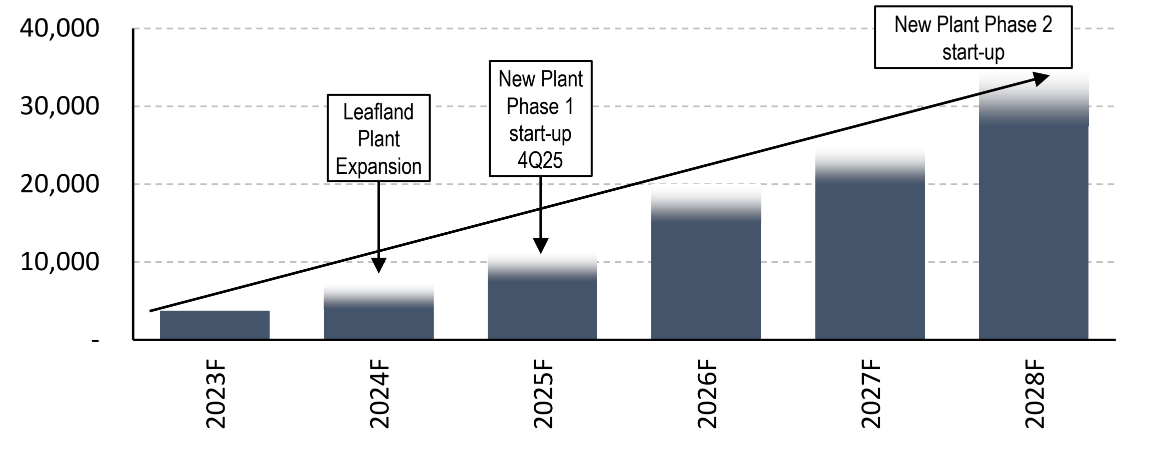
Building Sustainable Free Cash Flow for the Long-Term

A history of profitable asset development and production growth that drives material free cash flow generation

Grande Prairie Production (Boe/d) (1)



Willesden Green Production (Boe/d) (1)



- Paramount has a proven track record of assembling material positions in key resource plays and solving for plateau production levels that can be sustained for 15+ years
  - **Grande Prairie:** Began meaningful Karr drilling program in 2016 and added Wapiti through the 2017 acquisition of Apache Canada. Methodically grew production from near zero to peak rates over 80,000 Boe/d
  - **Willesden Green Duvernay:** Land position acquired over multiple years at a low-cost with current plans to grow production from ~3,750 Boe/d in 2023 to targeted full-field development plateau of over 50,000 Boe/d

Highlights of 5-Year Outlook (1)	
2028 Annual Average Sales Volumes	140,000 to 155,000 Boe/d
Midpoint Annual Capital Expenditures	$850 million to $1.0 billion
Midpoint Cumulative After-Tax Free Cash Flow (1)	**~$2.8 Bn (~$19.40/sh.) (2)**

- No cash tax in five-year outlook until 2027 (3)

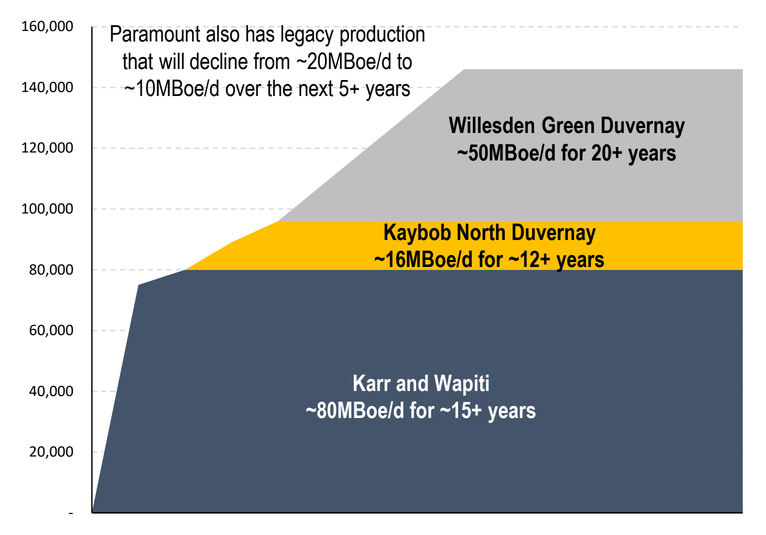
(1) The five-year outlook is based on preliminary planning and current market conditions and is subject to change. The stated anticipated cumulative free cash flow is based on the following assumptions: (i) the stated midpoint annual estimated capital expenditures; (ii) a compound annual production growth rate of 8% to 10% between 2023 and 2028; (iii) approximately $40 million in 2024 and thereafter approximately $45 million in average annual abandonment and reclamation costs, (iv) approximately $7 million in annual geological and geophysical expenses, (v) 2024 realized pricing of $56.40/Boe (US$80.00/Bbl WTI, US$3.50/MMBtu NYMEX, $2.84/GJ AECO) and thereafter commodity prices of US$75.00/Bbl WTI, US$4.00/MMBtu NYMEX and $3.55/GJ AECO, (vi) a 2024 $US/$CAD exchange rate of $0.735 and thereafter a $US/$CAD exchange rate of $0.740 and (vii) internal management estimates of future royalties, operating costs, transportation and NGLs processing costs and, beginning in 2027, cash taxes. **(2)** Based on 144.3MM outstanding Common Shares as at October 31, 2023. **(3)** See the Advisories Appendix – Forward-Looking Information for a description of certain of the key underlying assumptions.

Prudent Development of Inventory-Rich Opportunity Set

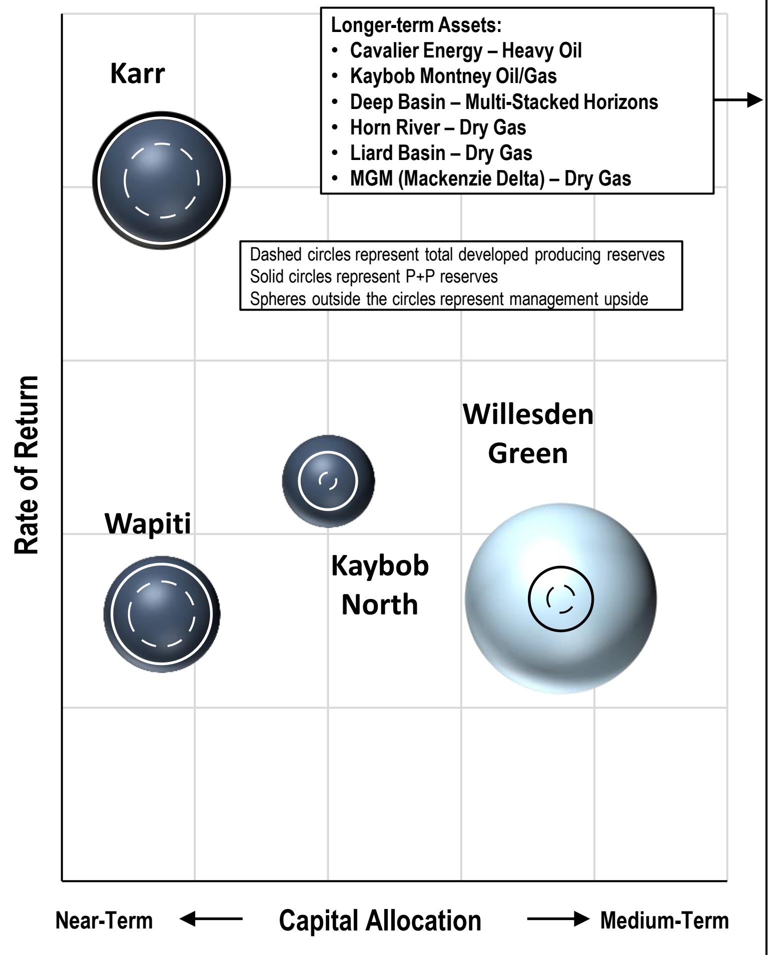
Paramount continues to allocate capital to its highest risk-adjusted return opportunities while maintaining balance sheet strength

- Significant inventory of opportunities across Paramount's land base at various stages in the development lifecycle
- Measured and focused approach to development
  - Targeting asset-level plateau production that can be sustained for 15 to 20+ years based on management estimates of full field development location count

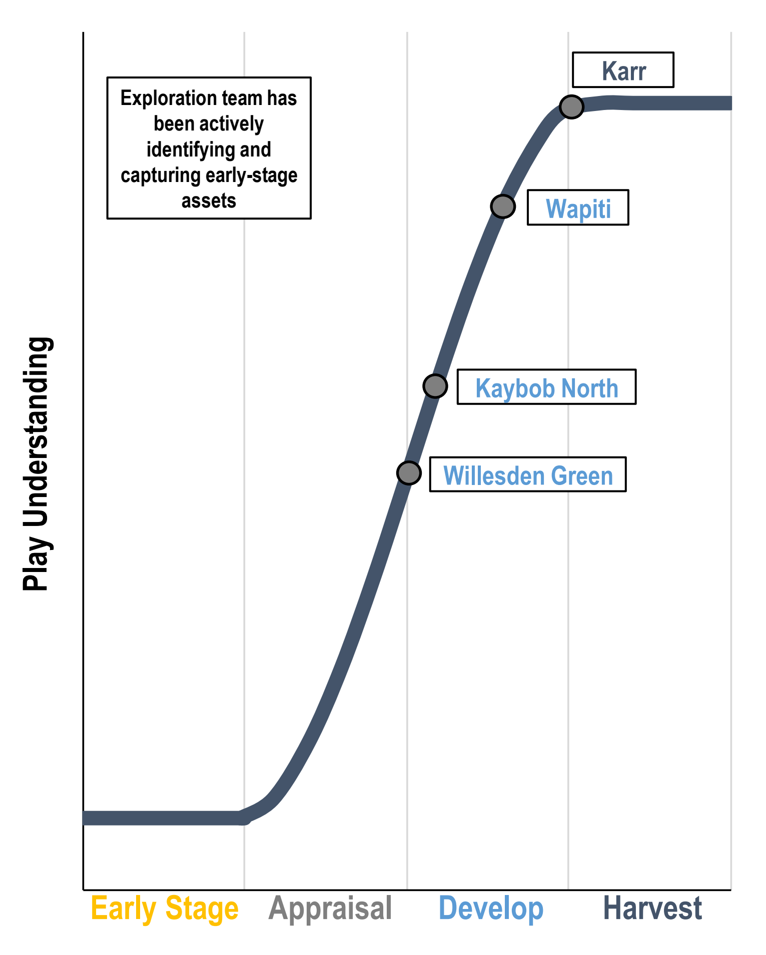
Potential Plateau Production (Boe/d) (1)



Significant Asset Optionality & Value (2)



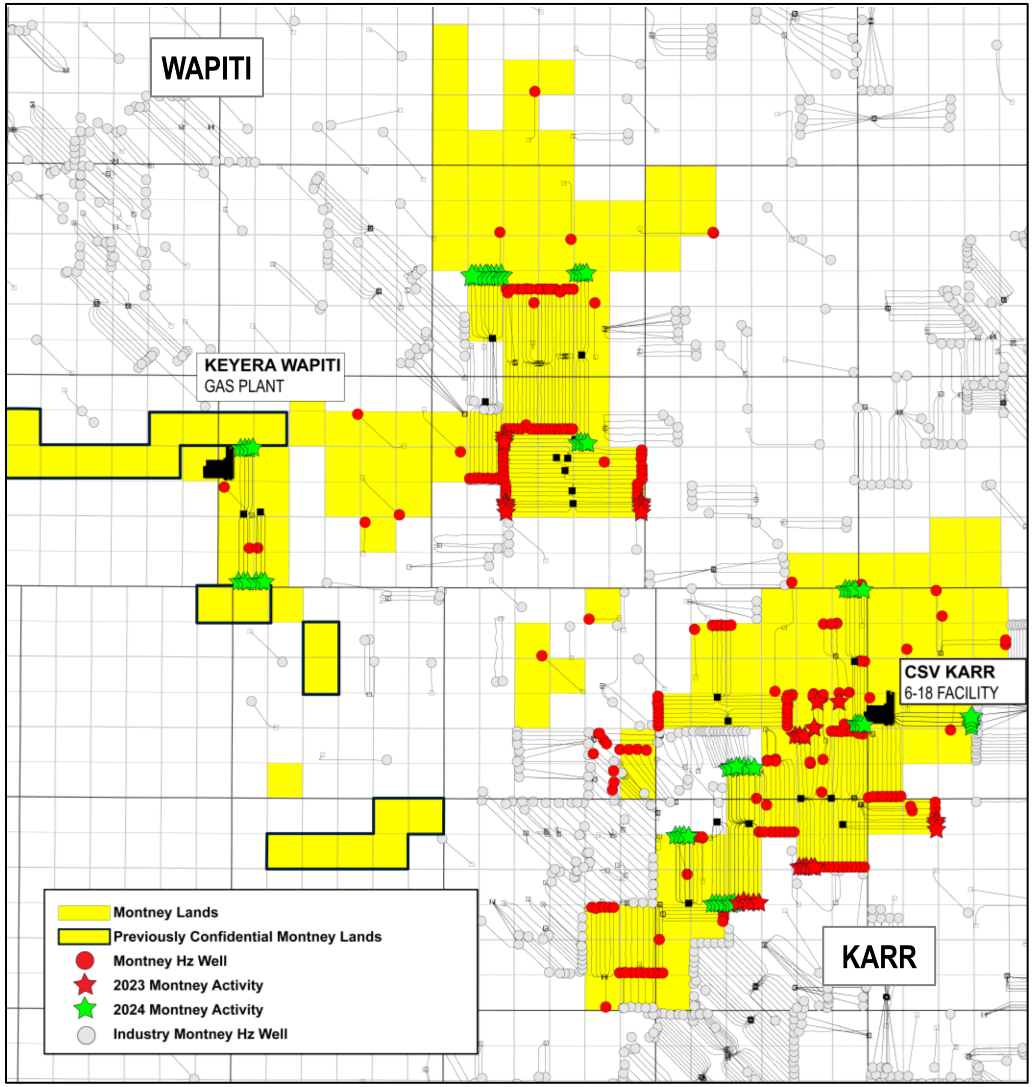
Stage of Development



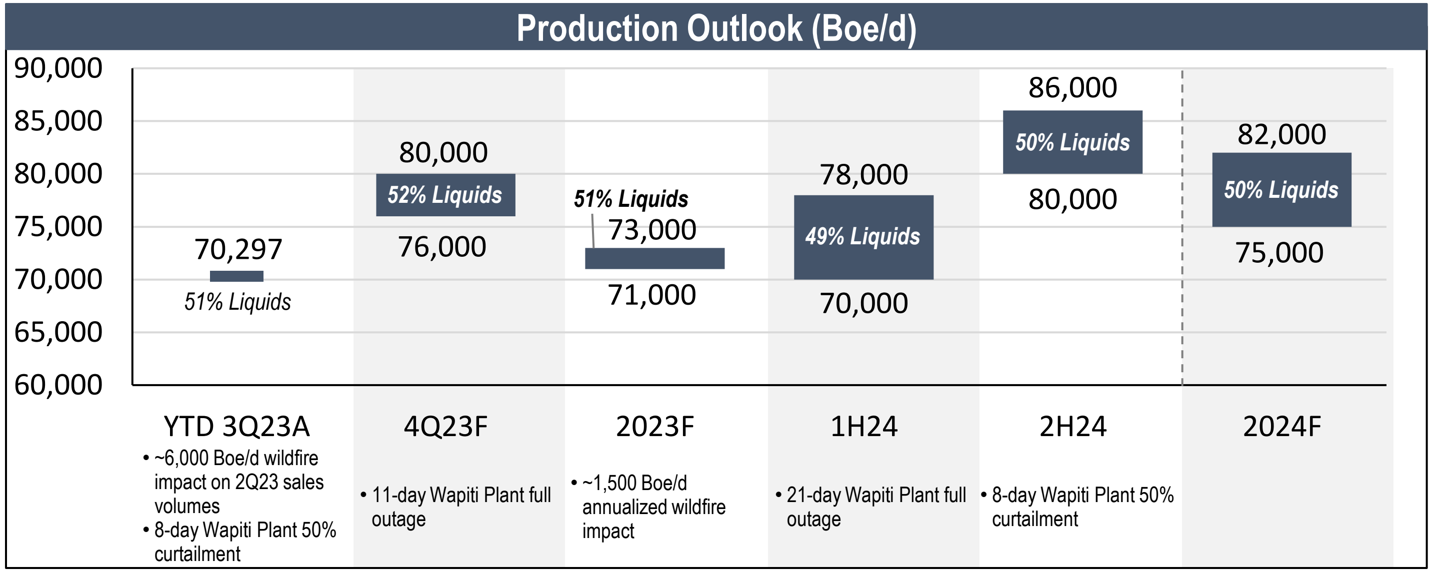
(1) Based on management estimates of play data and undeveloped drilling locations as described on pages 8, 9, 11, 13 and 14. See Advisories Appendix – Play Data and Undeveloped Locations. **(2)** Paramount's expectation of rate of return (as of November 1, 2023) vs. the relative net present value of future net revenue, discounted at 10 percent, of: (i) proved plus probable developed producing reserves as estimated by McDaniel in the McDaniel Report (dashed lines), (ii) proved plus probable reserves as estimated by McDaniel in the McDaniel Report (solid lines), and (iii) management undeveloped locations not assigned reserves, calculated, for illustrative purposes only, by assigning such locations a value equivalent to the average value by property assigned to undeveloped locations in the McDaniel Report (spheres outside the lines). The chart is provided solely to provide readers with information respecting management's views of the relative rates of return and potential values of its major properties. The illustrative value of management undeveloped locations should not be relied on as an estimate or evaluation of reserves or resources associated with the Company's properties. See Advisories Appendix – Reserves Data, Play Data and Undeveloped Locations.

Grande Prairie Region

Paramount has expanded its core Montney land position in the Grande Prairie Region



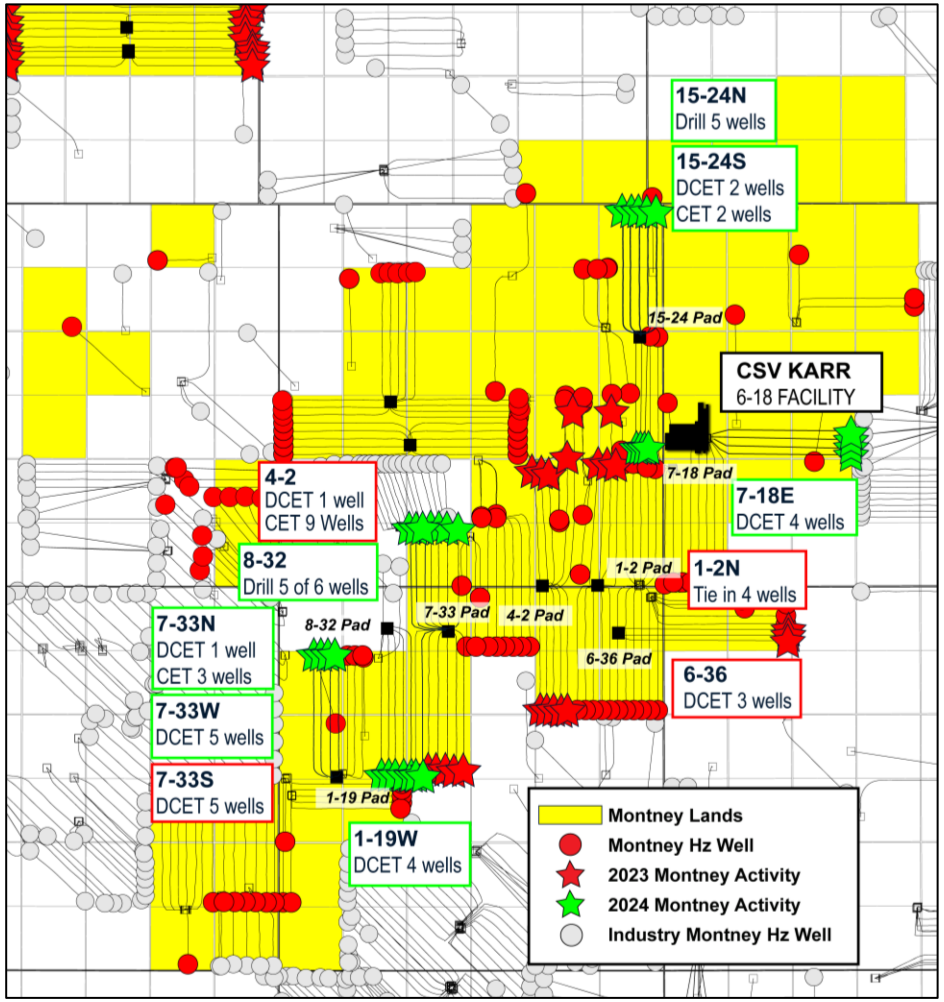
- Paramount holds approximately 109,000 net acres of Montney rights at Karr and Wapiti [(1)]
- Actively began development in 2016 with 174 wells brought onstream to the end of September 2023
- Infrastructure debottlenecking project completed in 2023
- 2024 activities include 41 drills, 36 wells to be brought onstream
- Montney land position has been expanded: added 10 net sections of new land at Karr and Wapiti and disclosed a further 10 net sections at Wapiti that were previously held confidentially
- Management high-graded undeveloped location count of 209 wells at Karr (middle Montney development) and 235 wells at Wapiti [(2)]



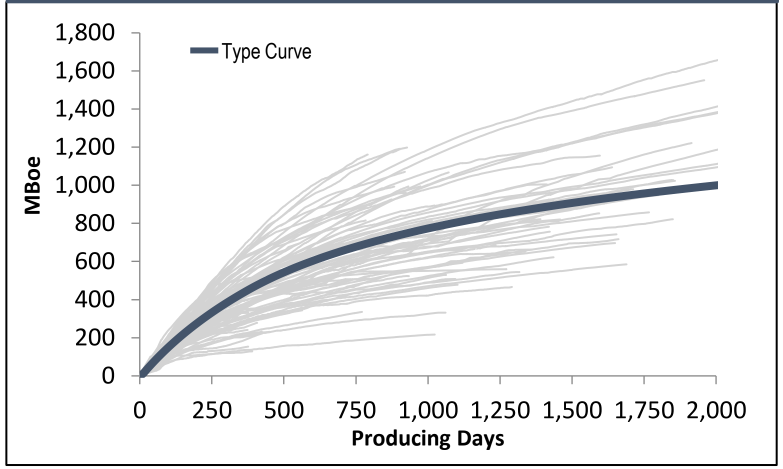
(1) As of November 1, 2023. **(2)** See Advisories Appendix – Undeveloped Locations, including for a description of undeveloped location assigned reserves in the McDaniel Report as at December 31, 2022.

Karr Activity and Production Performance

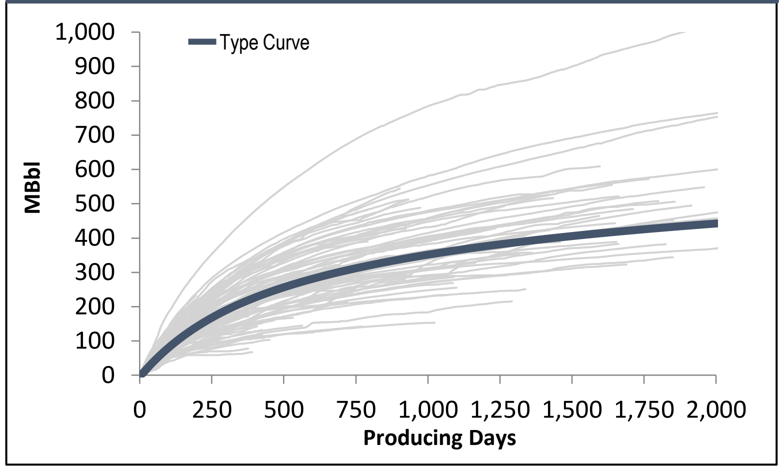
Paramount's newest Montney wells at Karr are exhibiting strong performance, demonstrating the quality of the entire land block



Cumulative Boe (1)



Cumulative NGLs (1)



Play Data – 3,000m Avg. Lateral Length (2)

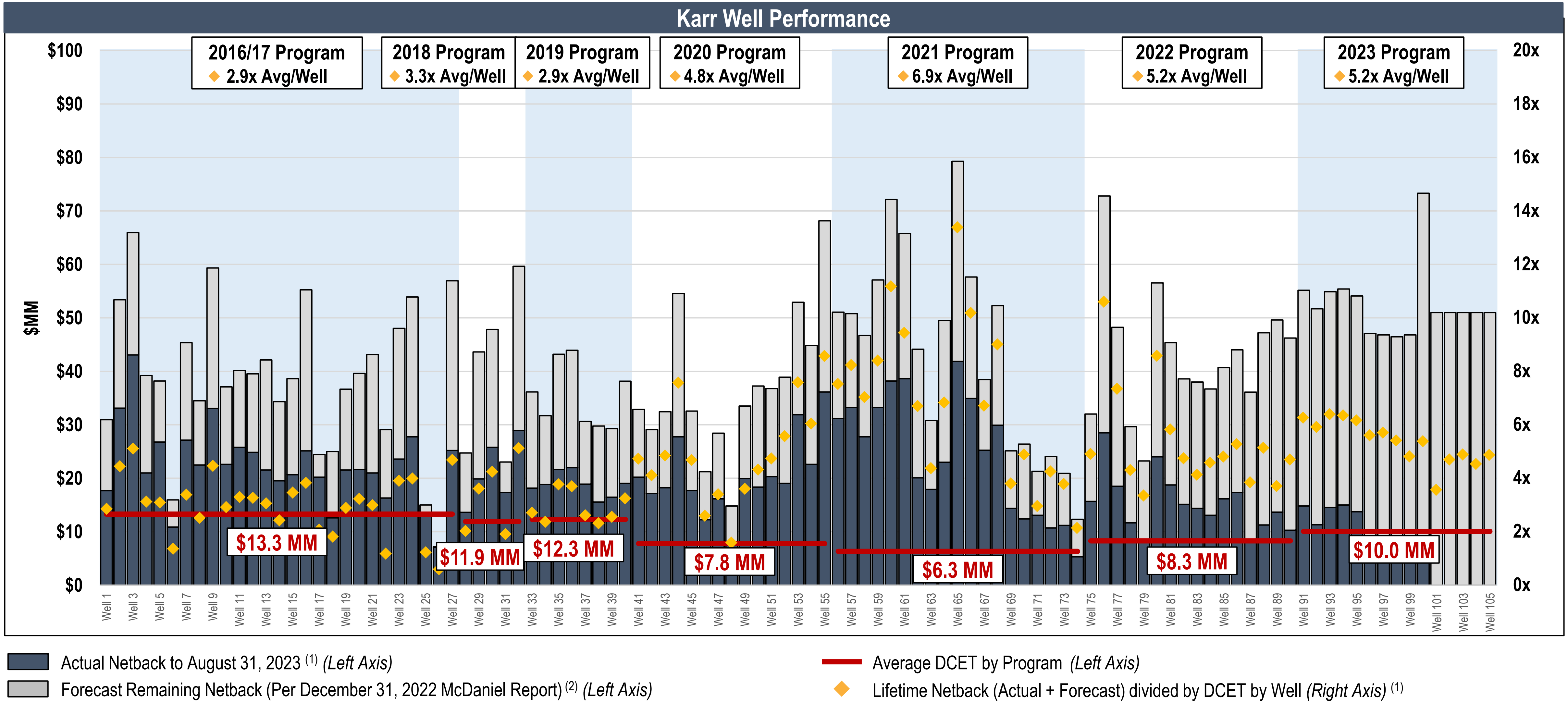
IP 365 *(Boe/d)*	1,189
IP 365 CGR *(Bbl/MMcf)*	186
Sales Volume *(MBoe)*	1,471
Average CGR *(Bbl/MMcf)*	137
Sales Gas Volume *(Bcf)*	4.6
Sales Condensate *(MBbl)*	591
DCET *($MM)*	$9.1

- Highly productive, liquids-rich wells drive attractive half-cycle economics
- Estimated per well sales volumes of ~1.5 MMBoe
  - Implied capital efficiency of ~$7,700/Boe/d (3)
- Grande Prairie PDP F&D costs were $9.61/Boe in 2022 (3)
  - Results in a recycle ratio of 4.6x when using Karr's 2022 netback of $44.62/Boe (3)

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 10 percent and liquids sales volumes were lower by approximately 7 percent due to shrinkage. **(2)** Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(3)** Implied capital efficiency is a supplementary financial measure. F&D costs and recycle ratio are non-GAAP ratios. Refer to "Specified Financial Measures", "Oil and Gas Measures and Definitions" and "Play Data" in the Advisories Appendix for more information on these measures.

Karr Performance

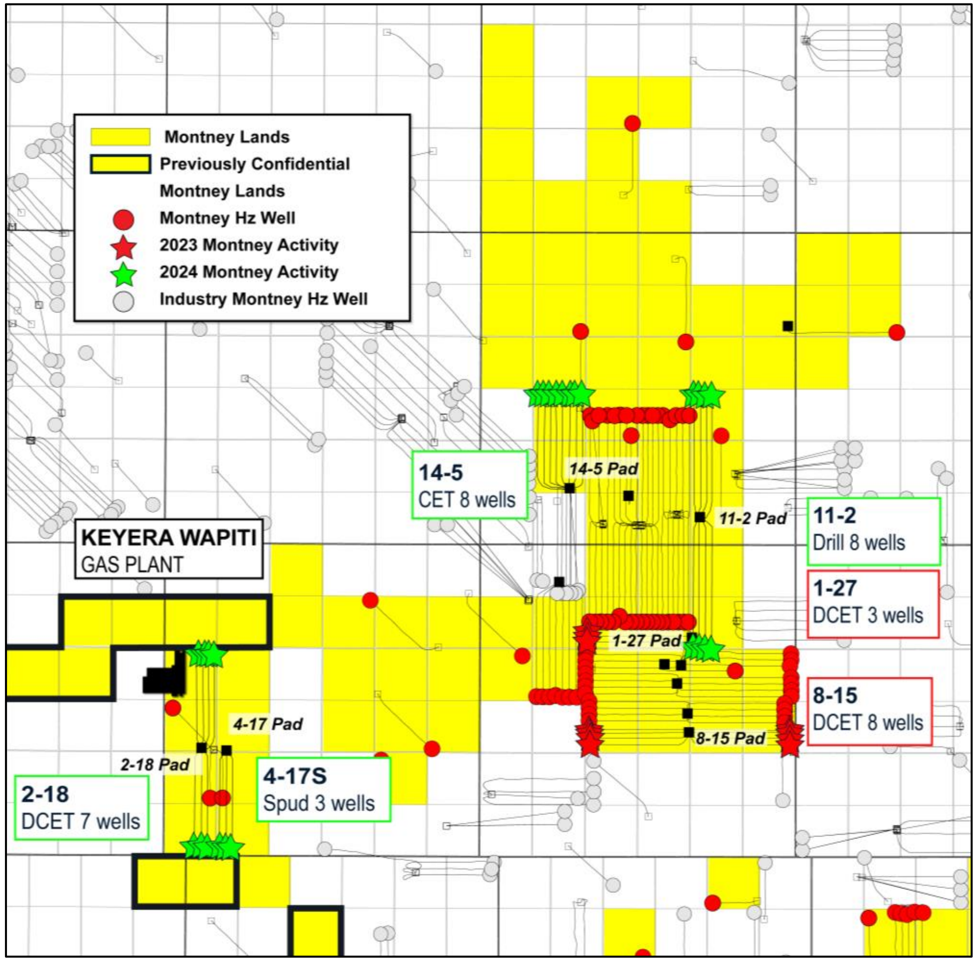
Wells exhibit strong returns and quick payouts



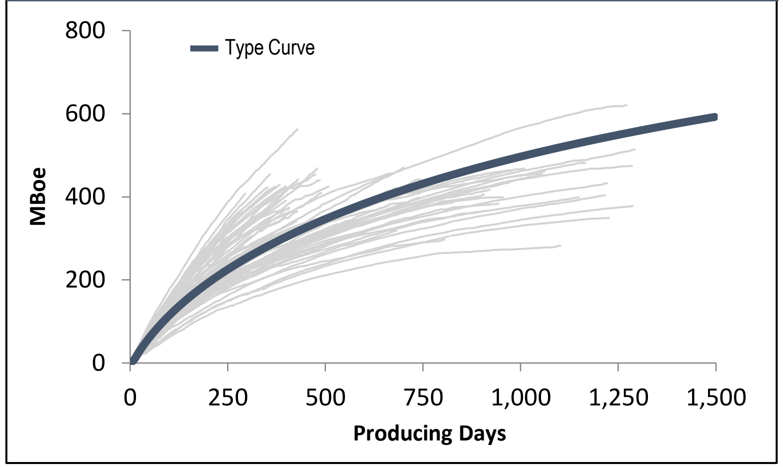
(1) Netback is a non-GAAP financial measure. Lifetime Netback divided by DCET by Well is a non-GAAP ratio. See Advisories Appendix – Specified Financial Measures. **(2)** See Advisories Appendix – Reserves Data. Amounts represent undiscounted forecast proved plus probable netback over the remaining life of each well as included in the McDaniel Report less actual netback between January 1, 2023 and August 31, 2023.

Wapiti Activity and Production Performance

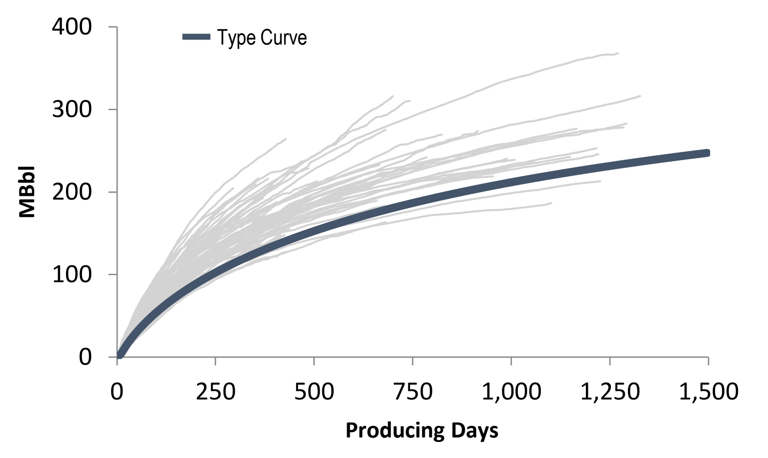
Approximately half of Paramount's activity in 2024 will be the development of its more gas prone lands to the west



Cumulative Boe (1)



Cumulative NGLs (1)



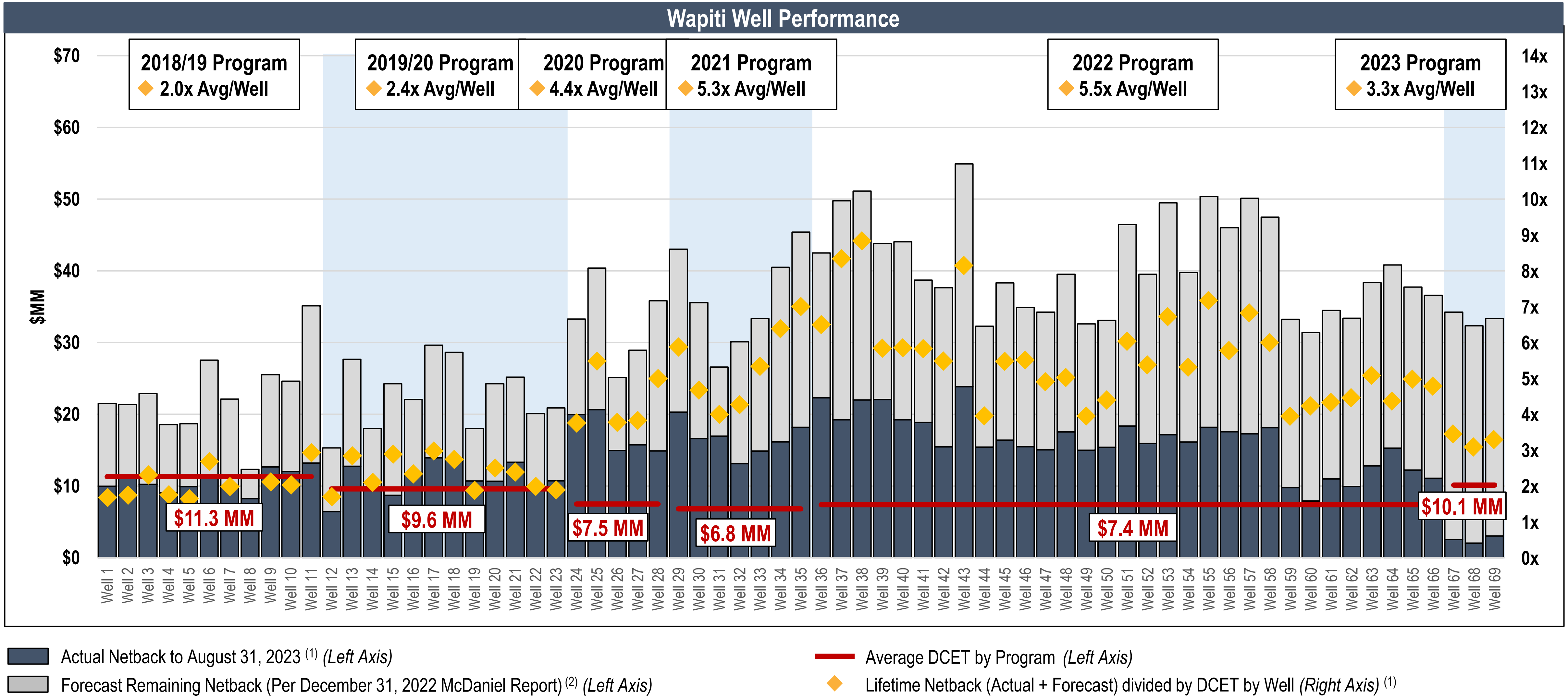
Play Data – 3,000m Avg. Lateral Length (2)	
IP 365 *(Boe/d)*	778
IP 365 CGR *(Bbl/MMcf)*	213
Sales Volume *(MBoe)*	1,043
Average CGR *(Bbl/MMcf)*	149
Sales Gas Volume *(Bcf)*	3.6
Sales Condensate *(MBbl)*	393
DCET *($MM)*	$9.4

- Implied capital efficiency of ~$12,100/Boe/d (3)
- Grande Prairie PDP F&D costs were $9.61/Boe in 2022 (3)
  - Results in a recycle ratio of 5.9x when using Wapiti's 2022 netback of $56.42/Boe (3)

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 9 percent and liquids sales volumes were lower by approximately 2 percent due to shrinkage. **(2)** Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(3)** Implied capital efficiency is a supplementary financial measure. Netback is a non-GAAP financial measure. F&D costs and recycle ratio are non-GAAP ratios. Refer to "Specified Financial Measures", "Oil and Gas Measures and Definitions" and "Play Data" in the Advisories Appendix for more information on these measures.

Wapiti Performance

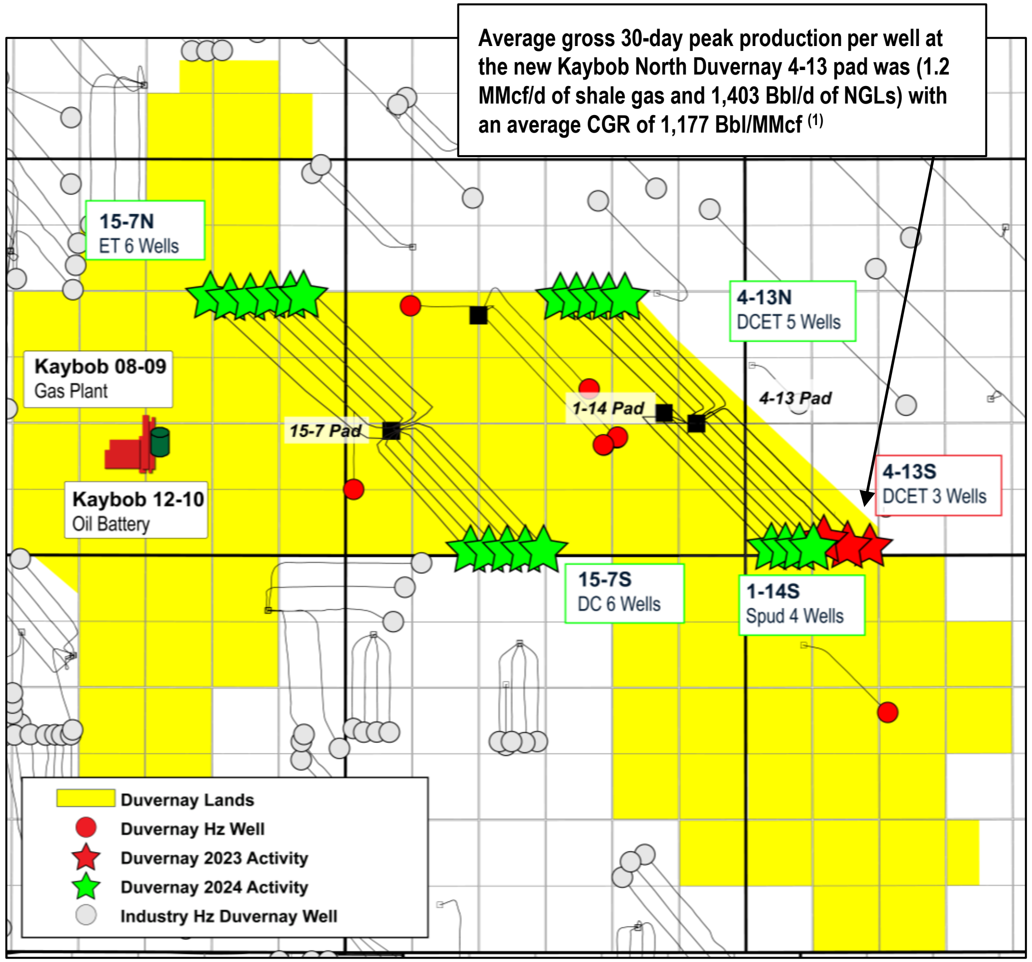
Wapiti wells are generating strong returns on invested capital



(1) Netback is a non-GAAP financial measure. Lifetime Netback divided by DCET by Well is a non-GAAP ratio. See Advisories Appendix – Specified Financial Measures. **(2)** See Advisories Appendix – Reserves Data. Amounts represent undiscounted forecast proved plus probable netback over the remaining life of each well as included in the McDaniel Report less actual netback between January 1, 2023 and August 31, 2023.

Kaybob North Duvernay Overview

Recent results have confirmed Paramount's decision to commence the active development of its Kaybob North Duvernay asset



- Results from the new 4-13S pad are among the best ever recorded for Duvernay wells in the area
- Paramount plans to grow production from 2,000 Boe/d in 2023 to as high as 14,000 Boe/d within its five-year outlook
- 2024 plans include drilling and bringing onstream 11 Duvernay wells and the commencement of drilling a four well pad that has been accelerated into the fourth quarter of 2024
- Paramount has ownership in strategic facilities and infrastructure including the 8-9 Gas Plant and 12-10 Oil Battery, with additional debottlenecking activities ongoing
- The Company owns and operates a crude oil terminal capable of capturing incremental value in price differentials with capacity to handle future growth

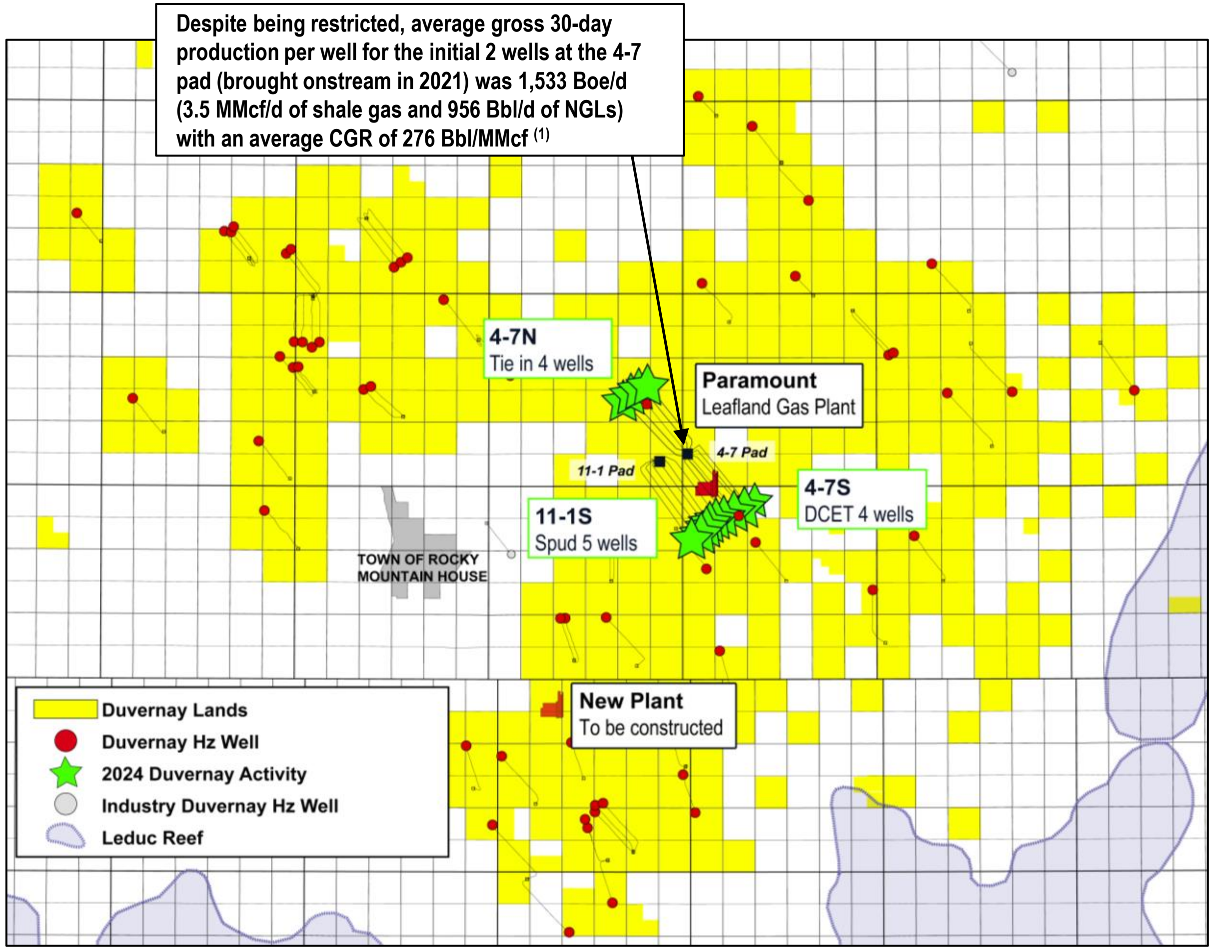
Play Data – 4,200m Avg. Lateral Length (2)	
IP 365 *(Boe/d)*	593
IP 365 CGR *(Bbl/MMcf)*	515
Sales Volume *(MBoe)*	880
Average CGR *(Bbl/MMcf)*	366
Sales Gas Volume *(Bcf)*	1.6
Sales Condensate *(MBbl)*	575
DCET *($MM)*	$11.8

- Targeting plateau production of ~16,000 Boe/d
- 150 full field development locations based on ~320m inter-well spacing and lateral length of 4,200m (3)
- Implied capital efficiency of ~$19,900/Boe/d (4)

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 16 percent and liquids sales volumes were lower by approximately 13 percent due to shrinkage. 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 the condensate to gas ratio calculated by dividing wellhead NGLs volumes by wellhead natural gas volumes. See Advisories Appendix - Oil and Gas Measures and Definitions. **(2)** Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(3)** See Advisories Appendix – Undeveloped Locations, including for a description of undeveloped location assigned reserves in the McDaniel Report as at December 31, 2022. **(4)** Implied capital efficiency is a supplementary financial measure. Refer to "Specified Financial Measures" and "Play Data" in the Advisories Appendix for more information on this measure.

Willesden Green Duvernay Overview

Paramount is increasing development activities in its ~240,000 net acre core Duvernay area



- The Leafland Plant liquids handling expansion is planned to be onstream in early 2024
  - On startup of the expansion, four wells from the 4-7N pad are to be brought onstream
  - An additional four wells from the 4-7S pad are expected to come onstream in H2 2024
  - The drilling of the five well 11-1S pad is planned to commence late in 2024
- The second phase of development includes the construction of a new processing facility
  - Ultimate capacity of 150 MMcf/d of raw gas and 30,000 Bbl/d of raw liquids handling
    - Expected to be built in three phases of 50 MMcf/d and 10,000 Bbl/d each
    - First phase expected to be onstream in the fourth quarter of 2025
- Paramount controls approximately 240,000 net acres of contiguous land with over 700 internally estimated Duvernay drilling locations supporting targeted plateau production of over 50,000 Boe/d that can be sustained for over 20 years (2)

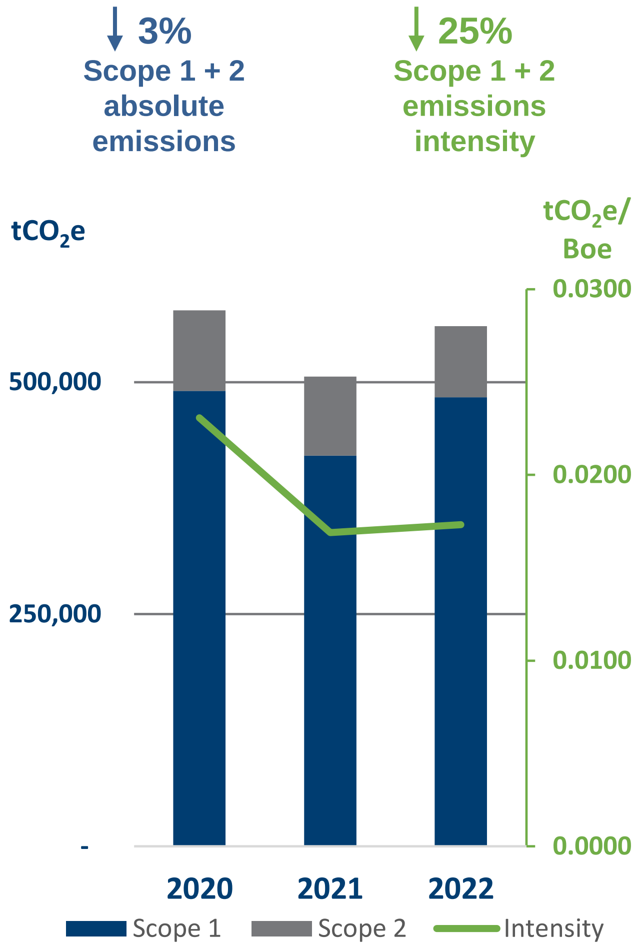
Play Data at 4,000m Avg. Lateral Length (3)	
IP 365 *(Boe/d)*	756
IP 365 CGR *(Bbl/MMcf)*	280
Sales Volume *(MBoe)*	1,219
Average CGR *(Bbl/MMcf)*	209
Sales Gas Volume *(Bcf)*	2.7
Sales Condensate *(MBbl)*	574
DCET *($MM)*	$12.8

- Implied capital efficiency of ~$16,900/Boe/d (4)
  - The Company expects capital efficiencies to improve over time as it develops the play

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 9 percent and liquids sales volumes were lower by approximately 17 percent due to shrinkage. 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 the condensate to gas ratio calculated by dividing wellhead NGLs volumes by wellhead natural gas volumes. See Advisories Appendix - Oil and Gas Measures and Definitions. **(2)** See Advisories Appendix – Undeveloped Locations, including for a description of undeveloped location assigned reserves in the McDaniel Report as at December 31, 2022. **(3)** Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(4)** Implied capital efficiency is a supplementary financial measure. Refer to "Specified Financial Measures" and "Play Data" in the Advisories Appendix for more information on this measure.

Environmental, Social and Governance ("ESG")

Paramount prides itself in delivering value to all stakeholders in a responsible manner



Environmental

- Participated in the 2022 CDP Climate Change Survey and received a score of "B"
  - Global oil and gas sector averaged "C"
  - Global, all sectors averaged "C"
- Bi-fuel drilling rigs contributed to a ~62% reduction in per well diesel consumption since 2018
- Equipping new pads with instrument air where possible to minimize methane emissions
- Recently replaced 26 chemical pumps with solar as part of a pilot program, reducing vented emissions
- Proactively managing decommissioning and reclamation obligations; over 650 wells decommissioned and 740 hectares reclaimed since 2017

Social

- Fosters a safety conscious culture with written policies and procedures to protect the health and safety of those involved with and affected by our operations
- Supports a wide range of community and charitable organizations both financially and through volunteer hours
- Committed to creating and maintaining an environment that respects diverse traditions, heritages and experiences

Governance

- 75% independent board members; independent Lead Director
- All board committees fully independent
- Environmental, Health and Safety Committee of the Board of Directors and senior management provide oversight of ESG related matters
- 3 of 8 (37.5%) board members are women
- Minimum shareholding requirements for directors
- Officers and directors prohibited from hedging Paramount securities
- Loans to officers and directors prohibited
- Code of Ethics and Code of Business Conduct Policy
- Anonymous Whistleblower Policy and portal

Strategic and Long-Term Investments

Paramount holds strategic positions in a number of public and private entities

Summary of Investments & Other Assets	
Investments in Public Companies (1)	~$500 million
Investments in Private Companies (2)	~$80 million
Drilling Rigs – Book Value (2)	~$80 million
Undeveloped Land	Not quantified
Total	**~$660 million**

Other Long-Term Resources

Clearwater/Bluesky heavy oil

Horn River Basin natural gas

Liard Basin natural gas

Mackenzie Delta natural gas

Thermal oil

- Minimal ongoing holding costs, lease rental only
- Maintain flexibility to determine development timeline
- Prospective for future free cash flow through joint ventures, farm outs or dispositions

Fox Drilling

Wholly owned by Paramount

- Five triple-sized walking rigs
- One conventional triple-sized rig
- Construction of the new super-spec walking rig is now complete and is being deployed at Wapiti in the fourth quarter

Cavalier Energy Inc.

Wholly owned by Paramount

- Cavalier Energy's lands are prospective for in-situ thermal oil recovery and cold flow heavy oil
- 1.357 million gross acres of land located primarily in the Athabasca and Peace River regions of Alberta
- 276,000 net acres with Clearwater and Bluesky potential

Sultran

Paramount holds a ~16% ownership

- Supply chain and logistics solutions for bulk commodities
- Wholly-owned BC terminal facilities (Pacific Coast Terminals Co. Ltd.)

Canadian Premium Sand Inc.

Paramount holds a ~16% ownership

- Planning to build the only ultra high-clarity patterned solar glass manufacturing facility in North America

Liard Basin

Besa River Shale Play

- Prospective feedstock for west coast LNG
- Paramount holds ~86,000 net acres

Horn River Basin

Muskwa Shale Play

- Prospective feedstock for west coast LNG
- Paramount holds ~35,000 (19,000 net) acres

Mackenzie Delta

- ~182,000 (30,000 net) acres

Central Mackenzie

- 301,000 (177,000 net) acres

(1) Market value of public companies as at September 30, 2023 (includes ~37.3 million shares of NuVista Energy Ltd. @ $13.00/share). **(2)** Carrying value as at September 30, 2023. Investments in Private Companies include the Company's investments in Sultran and Westbrick Energy Ltd. For further details refer to Paramount's interim consolidated financial statements as at and for the three and nine months ended September 30, 2023.

Paramount Investment Attributes

Paramount offers a unique investment proposition

- 45+ year history of responsible energy development and environmental stewardship
- Extensive portfolio of liquids-rich resource plays in the Montney and Duvernay
- Proven track record of building large, contiguous land positions and developing them into material and sustainable free cash flow engines
- Risk adjusted returns-focused capital allocation strategy supported by rigorous full-cycle analysis
- Meaningful free cash flow profile of ~$2.8 billion (1) (~$19.40 per basic share (2)) over the next five years
- No cash tax in five-year outlook until 2027 (3)
- Strong liquidity position with an undrawn $1.0 billion financial covenant based revolving credit facility at quarter end (May 2026 maturity)
- Stakeholder-aligned management and board with significant insider ownership
- Regular monthly dividend has been increased over six-fold to $0.125 per share through four increases
- Special cash dividend of $1.00/share paid in January 2023

(1) The five-year outlook is based on preliminary planning and current market conditions and is subject to change. **(2)** Based on 144.3MM outstanding Common Shares as at October 31, 2023. (3) See the Advisories Appendix – Forward-Looking Information for a description of certain of the key underlying assumptions.

Appendix

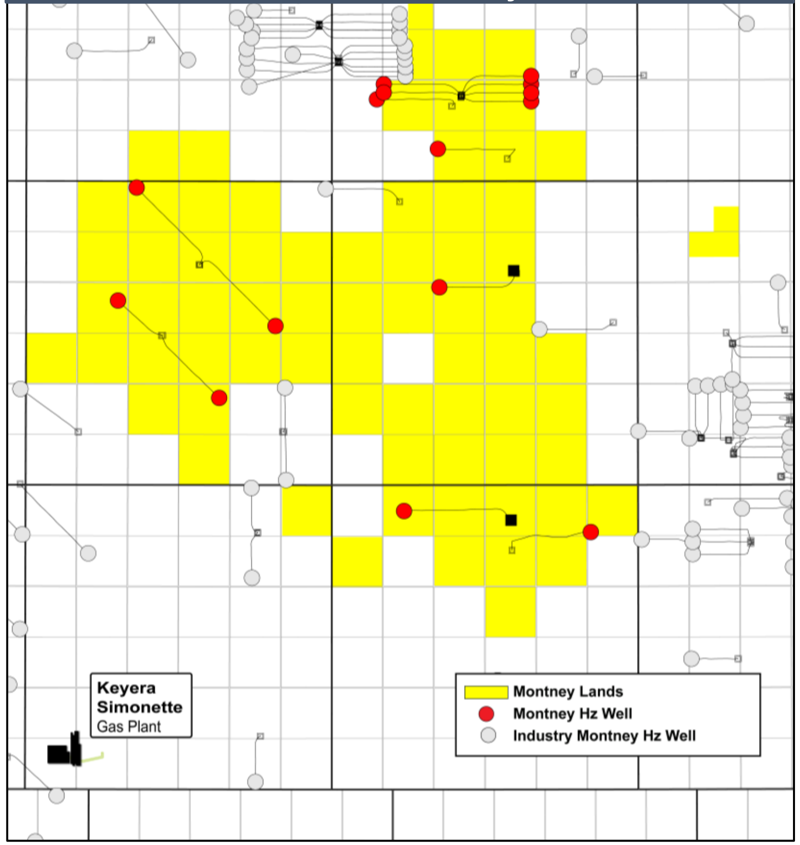
Other Montney Assets at Kaybob

Despite limited capital being currently deployed, assets have significant running room for future development

Kaybob North Montney Oil

- 26 full field development locations [(1)]

Ante Creek Montney Oil



- 99 full field development locations [(1)]

(1) See Advisories Appendix – Undeveloped Locations, including for a description of undeveloped location assigned reserves in the McDaniel Report as at December 31, 2022.

Appendix

The following summarizes the performance of the wells at Karr

	DCET Costs *($MM)*	Peak 30-Day [1] Total *(Boe/d)*	Peak 30-Day [1] Wellhead NGLs *(Bbl/d)*	Peak 30-Day [1] Wellhead Shale Gas *(MMcf/d)*	Peak 30-Day [1] CGR [3] *(Bbl/MMcf)*	Cumulative [2] Total *(MBoe)*	Cumulative [2] Wellhead NGLs *(MBbl)*	Cumulative [2] Wellhead Shale Gas *(MMcf)*	Cumulative [2] CGR [3] *(Bbl/MMcf)*	Days on Production
2023 Wells										
15 wells (Avg. per well)	$10.0	2,272	1,355	5.5	247	252	130	732	177	138
2022 Wells										
16 wells (Avg. per well)	$8.3	1,602	864	4.4	195	371	167	1,222	137	401
2021 Wells										
19 wells (Avg. per well)	$6.3	1,872	988	5.3	186	683	307	2,254	136	719
2020 Wells										
15 wells (Avg. per well)	$7.8	1,548	907	3.8	236	653	315	2,036	155	1,028
2019 Wells										
8 wells (Avg. per well)	$12.3	1,825	1,262	3.4	373	707	425	1,690	251	1,365
2018 Wells										
5 wells (Avg. per well)	$11.9	1,760	1,051	4.3	247	830	433	2,381	182	1,385
2016/2017 Wells										
27 wells (Avg. per well)	$13.3	1,969	1,171	4.8	245	957	470	2,928	160	1,733

**Paramount is a single stream reporter, and as such, all public production data represents recombined gas.*

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes were approximately 10 percent lower and NGLs sales volumes were approximately 7 percent lower due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes shown are 30-day peak rates 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. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. See "Oil and Gas Measures and Definitions" in the Advisories Appendix. **(2)** Cumulative is the aggregate production measured at the wellhead to October 24, 2023. Natural gas sales volumes were approximately 10 percent lower and NGLs sales volumes were approximately 7 percent lower due to shrinkage. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. **(3)** CGR means condensate to gas ratio calculated by dividing wellhead NGLs by wellhead natural gas volumes.

Appendix

The following summarizes the performance of the wells at Wapiti

	DCET Costs ($MM)	Peak 30-Day (1) Total (Boe/d)	Peak 30-Day (1) Wellhead NGLs (Bbl/d)	Peak 30-Day (1) Wellhead Shale Gas (MMcf/d)	Peak 30-Day (1) CGR (3) (Bbl/MMcf)	Cumulative (2) Total (MBoe)	Cumulative (2) Wellhead NGLs (MBbl)	Cumulative (2) Wellhead Shale Gas (MMcf)	Cumulative (2) CGR (3) (Bbl/MMcf)	Days on Production
2023 Wells										
3 wells (Avg. per well)	$10.1	1,187	730	2.7	267	81	48	198	242	80
2022 Wells										
31 wells (Avg. per well)	$7.4	1,582	892	4.1	215	380	178	1,210	147	373
2021 Wells										
7 wells (Avg. per well)	$6.8	1,292	794	3.0	266	373	216	942	229	663
2020 Wells										
5 wells (Avg. per well)	$7.5	1,189	795	2.4	336	426	263	977	269	726
2019/2020 Wells										
12 wells (Avg. per well)	$9.6	1,588	1,044	3.3	320	411	239	1,033	231	941
2018/2019 Wells										
11 wells (Avg. per well)	$11.3	1,051	722	2.0	366	445	263	1,093	241	1,231

**Paramount is a single stream reporter, and as such, all public production data represents recombined gas.*

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes were approximately 9 percent lower and NGLs sales volumes were approximately 2 percent lower due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes shown are 30-day peak rates 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. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. See "Oil and Gas Measures and Definitions" in the Advisories Appendix. **(2)** Cumulative is the aggregate production measured at the wellhead to October 24, 2023. Natural gas sales volumes were approximately 9 percent lower and NGLs sales volumes were approximately 2 percent lower due to shrinkage. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. **(3)** CGR means condensate to gas ratio calculated by dividing wellhead NGLs by wellhead natural gas volumes.

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Forward-Looking Information

Certain statements in this presentation constitute forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "anticipate", "believe", "estimate", "will", "expect", "plan", "intend", "propose", or similar words suggesting future outcomes or an outlook.

Forward-looking information in this presentation includes, but is not limited to: (i) forecast sales volumes for 2023 and 2024 and certain periods therein; (ii) planned capital expenditures in 2023 and 2024 and the allocation thereof; (iii) planned abandonment and reclamation expenditures in 2023 and 2024; (iv) forecast free cash flow in 2023 and 2024; (v) the Company's free cash flow priorities; (vi) the potential payment of future dividends; (vii) illustrative adjusted funds flow in 2023 and 2024; (viii) anticipated geological and geophysical expenses; (ix) planned future production at Grande Prairie, Kaybob North Duvernay and Willesden Green Duvernay; (x) the Company's five-year outlook for 2028 average annual sales volumes, capital expenditures and cumulative free cash flow; (xi) the statement that Paramount does not forecast cash tax in its five-year outlook until 2027; (xii) targeted potential plateau production rates and the years of production that may be supported by undeveloped locations at Karr and Wapiti, Kaybob North Duvernay and Willesden Green; (xiii) anticipated legacy production declines; (xiv) potential rates of return or value for the Company’s properties; (xv) 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 and infrastructure, including the new facility at Willesden Green; (xvi) expected Grande Prairie sales volumes in 2024; (xvii) the expected realization of capital cost efficiencies at Kaybob North Duvernay and Willesden Green Duvernay; (xviii) undeveloped drilling locations at various properties; (xix) play data, anticipated well performance and forecast netback for various properties; and (xx) general business strategies and objectives.

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 presentation or Paramount’s continuous disclosure documents: (i) future commodity prices; (ii) the impact of international conflicts, including the Russian invasion of the Ukraine; (iii) royalty rates, taxes and capital, operating, general & administrative and other costs; (iv) foreign currency exchange rates, interest rates and the rate and impacts of inflation; (v) general business, economic and market conditions; (vi) the performance of wells and facilities; (vii) the availability to Paramount of the required capital to fund its exploration, development and other operations and meet its commitments and financial obligations; (viii) 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; (ix) the ability of Paramount to secure adequate processing, transportation, fractionation and storage capacity on acceptable terms and the capacity and reliability of facilities; (x) the ability of Paramount to market its production successfully; (xi) 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; (xii) the timely receipt of required governmental and regulatory approvals, including approvals required for the expansion and construction of facilities at Willesden Green; (xiii) the application of regulatory requirements respecting abandonment and reclamation; and (xiv) 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 facilities at Willesden Green, and facility turnarounds and maintenance).

In addition to the above, forecast 2023 free cash flow is based on (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 $52.60/Boe (US$77.99/Bbl WTI, US$3.34/MMBtu NYMEX, $2.72/GJ AECO), (v) a $US/$CAD exchange rate of $0.746, (vi) royalties of $7.60/Boe, (vii) operating costs of $12.65/Boe and (vii) transportation and NGLs processing costs of $3.90/Boe. Assumed pricing of US$80.00/Bbl WTI, US$3.50/MMBtu NYMEX and $3.08/GJ AECO and an assumed $US/$CAD exchange rate of $0.755 for the fourth quarter of 2023 is unchanged from previous guidance, but the stated amounts have been adjusted to incorporate actual results for the first three quarters of 2023.

Estimated 2024 free cash flow is based on (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 $56.40/Boe (US$80/Bbl WTI, US$3.50/MMBtu NYMEX, $2.84/GJ AECO), (v) a $US/$CAD exchange rate of $0.735, (vi) royalties of $8.80/Boe, (vii) operating costs of $12.05/Boe and (vii) transportation and NGLs processing costs of $3.70/Boe.

With respect to the statement that there is no cash tax in the five-year outlook until 2027, taxable income varies depending on total income and expenses and estimates as to the timing of paying cash tax are sensitive to assumptions regarding commodity prices, production, cash from operating activities, capital spending levels, the allocation of free cash flow and acquisition and disposition transactions. Changes in these factors could result in the Company paying income taxes earlier or later than expected.

Although Paramount believes that the expectations reflected in such forward-looking information are reasonable based on the information available at the time of the preparation of this presentation, 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 current 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. These risks and uncertainties include and/or relate (but are not limited) to: (i) the risks set out in the Company’s Management’s & Discussion and Analysis for the three and nine months ended September 30, 2023; (ii) fluctuations in commodity prices; (iii) changes in capital spending plans and planned exploration and development activities; (iv) the potential for changes to the Company's five-year outlook for capital expenditures, cumulative free cash flow and sales volumes; (v) changes in foreign currency exchange rates, interest rates and the rate of inflation; (vi) 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; (vii) the ability to secure adequate processing, transportation, fractionation, and storage capacity on acceptable terms; (viii) operational risks in exploring for, developing, producing and transporting natural gas and liquids, including the risk of spills, leaks or blowouts; (ix) 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; (x) potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities); (xi) processing, pipeline, and fractionation infrastructure outages, disruptions and constraints; (xii) risks and uncertainties that may result in changes to the planned expansion and construction of facilities at Willesden Green, including the potential for changes to facility design or the timelines for construction prior to finalization or the failure to obtain required governmental and regulatory approvals; (xiii) risks and uncertainties involving the geology of oil and gas deposits; (xiv) the uncertainty of reserves estimates; (xv) general business, economic and market conditions; (xvi) 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); (xvii) changes in, or in the interpretation of, laws, regulations or policies (including environmental laws); (xviii) the ability to obtain required governmental or regulatory approvals in a timely manner, and to obtain and maintain leases and licenses; (xix) the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access; (xx) uncertainties as to the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination; (xxi) uncertainties regarding Indigenous claims and in maintaining relationships with local populations and other stakeholders; (xxii) the outcome of existing and potential lawsuits, insurance claims, regulatory actions, audits and assessments; and (xxiii) other risks and uncertainties described elsewhere in this document and in Paramount’s other filings with Canadian securities authorities. The foregoing list of risks is not exhaustive. For more information relating to risks, see the section titled "Risk Factors" in Paramount's annual information form for the year ended December 31, 2022, which is available on SEDAR+ at www.sedarplus.ca.

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In addition, 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 declaration and payment of any future dividends or the amount or timing of any such dividends

Certain forward-looking information in this press release, including forecast free cash flow in 2023 and 2024 and future periods, may also constitute a "financial outlook" within the meaning of applicable securities laws. A financial outlook involves statements about Paramount's prospective financial performance or position and is based on and subject to the assumptions and risk factors described above in respect of forward-looking information generally as well as any other specific assumptions and risk factors in relation to such financial outlook noted in this press release. Such assumptions are based on management's assessment of the relevant information currently available and any financial outlook included in this press release is provided for the purpose of helping readers understand Paramount's current expectations and plans for the future. Readers are cautioned that reliance on any financial outlook may not be appropriate for other purposes or in other circumstances and that the risk factors described above or other factors may cause actual results to differ materially from any financial outlook.

The forward-looking information and statements contained in this presentation are made effective as of November 1, 2023. The internally estimated play data information for Karr, Wapiti, Kaybob North Duvernay and Willesden Green contained at pages 8, 9, 11, 13 and 14 in this presentation has been prepared effective November 1, 2023. In each case, events or information subsequent to the applicable effective dates have not been incorporated. 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.

Specified Financial Measures

Non-GAAP Financial Measures

Netback 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 used 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.

Total Company netbacks for the applicable periods are summarized below:

	Three Months ended September 30				Year Ended			
	2023		2022		**2022**		2021	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**463.8**	***51.11***	618.9	*68.92*	**2,252.4**	***69.60***	1,383.6	*46.23*
Royalties	**(75.2)**	***(8.28)***	(89.4)	*(9.96)*	**(335.3)**	***(10.36)***	(127.0)	*(4.24)*
Operating expense	**(113.9)**	***(12.55)***	(110.0)	*(12.25)*	**(407.1)**	***(12.58)***	(340.4)	*(11.37)*
Transportation and NGLs processing	**(31.2)**	***(3.44)***	(34.4)	*(3.83)*	**(123.7)**	***(3.82)***	(114.5)	*(3.83)*
Sales of commodities purchased (1)	**42.1**	***4.64***	77.9	*8.67*	**272.0**	***8.41***	75.5	*2.52*
Commodities purchased (1)	**(39.2)**	***(4.32)***	(76.4)	*(8.51)*	**(267.0)**	***(8.25)***	(76.1)	*(2.54)*
	246.4	**27.16**	386.6	43.04	**1,391.3**	**43.00**	801.1	26.77

Grande Prairie Region netbacks for the applicable periods are summarized below:

	Three Months ended September 30				Year Ended			
	2023		2022		**2022**		2021	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**379.7**	***55.48***	457.5	*75.37*	**1,651.8**	***77.33***	1,006.1	*53.14*
Royalties	**(64.7)**	***(9.45)***	(70.5)	*(11.62)*	**(261.2)**	***(12.23)***	(87.2)	*(4.61)*
Operating expense	**(72.7)**	***(10.62)***	(68.1)	*(11.22)*	**(247.6)**	***(11.59)***	(205.3)	*(10.84)*
Transportation and NGLs processing	**(25.6)**	***(3.75)***	(25.7)	*(4.24)*	**(93.1)**	***(4.36)***	(82.9)	*(4.37)*
	216.7	***31.66***	293.2	*48.29*	**1,049.9**	***49.15***	630.7	*33.32*

Karr netbacks for the applicable periods are summarized below:

	Three Months ended September 30				Year Ended			
	2023		2022		**2022**		2021	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**251.7**	***55.74***	261.8	*74.70*	**985.0**	***74.86***	725.4	*51.78*
Royalties	**(39.2)**	***(8.68)***	(47.7)	*(13.62)*	**(190.2)**	***(14.46)***	(74.5)	*(5.32)*
Operating expense	**(44.0)**	***(9.75)***	(39.6)	*(11.29)*	**(149.3)**	***(11.35)***	(134.1)	*(9.57)*
Transportation and NGLs processing	**(20.2)**	***(4.47)***	(15.6)	*(4.46)*	**(58.4)**	***(4.43)***	(59.7)	*(4.26)*
	148.3	***32.84***	158.9	*45.33*	**587.1**	***44.62***	457.1	*32.63*

Wapiti netbacks for the applicable periods are summarized below:

	Three Months ended September 30				Year Ended			
	2023		2022		**2022**		2021	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**128.0**	***54.97***	195.7	*76.27*	**666.8**	***81.30***	280.7	*57.03*
Royalties	**(25.5)**	***(10.93)***	(22.8)	*(8.88)*	**(71.0)**	***(8.65)***	(12.7)	*(2.58)*
Operating expense	**(28.7)**	***(12.33)***	(28.5)	*(11.12)*	**(98.3)**	***(11.99)***	(71.2)	*(14.46)*
Transportation and NGLs processing	**(5.4)**	***(2.34)***	(10.1)	*(3.94)*	**(34.7)**	***(4.24)***	(23.2)	*(4.73)*
	68.4	***29.37***	134.3	*52.33*	**462.8**	***56.42***	173.6	*35.26*

(1) Sales of commodities purchased and commodities purchased are treated as corporate items and not allocated to individual regions or properties.

Advisories

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, lifetime netback divided by DCET by well and netback presented on $/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. The three-year average F&D costs contained in this presentation were calculated by dividing total F&D capital over the period by the aggregate reserves additions in the period. 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.sedarplus.ca or at www.paramountres.com, for a description of the net changes to reserves in each reserves category from the prior year. See "Oil and Gas Definitions and Measures" in the Advisories Appendix 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 "Oil and Gas Definitions and Measures" in the Advisories Appendix 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					
	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

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Lifetime netback divided by DCET by well is calculated by dividing the actual netback (a non-GAAP financial measure) for a well to August 31, 2023 plus the forecast total proved plus probable netback over the remaining life of each well as estimated in the McDaniel Report by the DCET costs for the well. This measure is used by investors and management to assess the relationship of netback from a well to the DCET costs for the well.

Netback on a $/Boe is calculated by dividing netback (a non-GAAP financial measure) for the applicable period by the total production during the period in Boe. This measure is used by investors and management to assess netback on a unit of production basis.

Capital Management Measures

Adjusted funds flow and free cash 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 15 – Capital Structure in the interim consolidated financial statements of Paramount as at and for the three and nine months ended September 30, 2023 for: (i) a description of the composition and use of these measures, and (ii) reconciliations of adjusted funds flow and free cash flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements, for the three and nine months ended September 30, 2023 and 2022.

Supplementary Financial Measures

Implied capital efficiency is a supplementary financial measure. See "Play Data" in this Advisories Appendix for a description of the calculation of implied capital efficiency.

Oil and Gas Measures and Definitions

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

This document contains disclosures expressed as "Boe", "$/Boe", "MBoe", "MMBoe" and "Boe/d". Natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil when converting natural gas to Boe. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. For the nine months ended September 30, 2023, the value ratio between crude oil and natural gas was approximately 35:1. 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 Advisories Appendix 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, except as noted in this Advisories Appendix under "Play Data", 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.

All information in this presentation respecting acres of land held is effective as of December 31, 2022 unless otherwise stated.

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.sedarplus.ca.

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Product Type Information

This presentation includes references to forecast sales volumes of "liquids". "Liquids" refers to light and medium crude oil, tight oil, heavy crude oil, condensate and ethane, propane and butane ("Other NGLs") combined. Below is further information respecting the composition of sales volumes or forecast sales volumes for applicable periods.

The Company forecasts that 2023 annual sales volumes will average between 95,000 Boe/d and 98,000 Boe/d (54% shale gas and conventional natural gas combined, 40% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 6% Other NGLs). Fourth quarter 2023 sales volumes are expected to average between 100,000 Boe/d and 103,000 Boe/d (53% shale gas and conventional natural gas combined, 41% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 6% Other NGLs).

The Company forecasts that 2024 annual sales volumes will average between 108,000 Boe/d and 116,000 Boe/d (53% shale gas and conventional natural gas combined, 40% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 7% Other NGLs). First half 2024 sales volumes are expected to average between 101,000 Boe/d and 111,000 Boe/d (54% shale gas and conventional natural gas combined, 40% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 6% Other NGLs). Second half 2024 sales volumes are expected to average between 115,000 Boe/d and 121,000 Boe/d (53% shale gas and conventional natural gas combined, 41% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 6% Other NGLs).

See "Product Type Information" at page 28 of the Company's Management's Discussion and Analysis for the three and nine months ended September 30, 2023 for a description of historical average sales volumes by the specific product types of shale gas, conventional natural gas, NGLs, light and medium crude oil, tight oil and heavy crude oil.

Reserves Data

Reserves data set forth in this presentation 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.sedarplus.ca or 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.

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Play Data

The internally estimated play data information for Karr, Wapiti, Kaybob North Duvernay and Willesden Green contained at pages 8, 9, 11, 13 and 14 in this presentation has been prepared effective November 1, 2023 by internal qualified reserves evaluators from Paramount in accordance with COGEH and using commodity prices of US$80.00/Bbl WTI, $3.25/MMBtu AECO and an exchange rate of US$0.755 for one Canadian dollar for the last three months of 2023, US$80.00/Bbl WTI, $3.00/MMBtu AECO and an exchange rate of US$0.735 for one Canadian dollar for 2024 and US$75.00/Bbl WTI, $3.75/MMBtu AECO and an exchange rate of US$0.740 for one Canadian dollar for 2025 and beyond. The play data has been prepared excluding certain wells with significant deviation in completion, lateral length and depletion or infrastructure constraints. The play data contains no adjustments or assumptions respecting unscheduled potential future facility and transportation constraints or outages. Underlying forecast economics are half-cycle economics and include only the cost to drill, complete, tie-in and equip wells. The forecasts do not take into account certain other capital costs, including those required to construct central processing facilities, regional gathering facilities, condensate stabilization facilities and other infrastructure and costs related to water disposal and wellbore optimization. Sales and production volumes presented in the play data have been estimated on the basis of an equal likelihood that actual volumes recovered will be greater or less than those estimated.

The metrics and terms “CGR”, “IP 365“, “IP 365 CGR”, “Sales Volumes”, “Average CGR”, “Sales Gas Volume”, “Sales Condensate”, “Implied Capital Efficiency” and “DCET” are used in presenting play data. “CGR” means condensate to gas ratio and, in the context of play data, is calculated by dividing sales condensate volumes by sales natural gas volumes. “IP 365” means the estimated average daily sales volumes of production over the initial 365 calendar days of production. “IP 365 CGR” means the estimated average CGR over the initial 365 calendar days of production. “Sales Volume” means the estimated aggregate potential sales volumes of production. “Average CGR” means the estimated average CGR over the life of the well. “Sales Gas Volume” means the estimated aggregate potential sales volumes of natural gas. “Sales Condensate” means the estimated aggregate potential sales volumes of condensate. “Implied Capital Efficiency” is calculated by dividing IP365 by DCET. “DCET” means estimated drilling, completion, equip and tie-in costs.

The play data contained in this presentation has been included for the purposes of informing readers as to certain assumptions and estimates relied on by management of Paramount as of the date of preparation for capital budgeting and forecasting purposes. The play data represents an estimate only respecting undeveloped locations in 2024 development plans, is subject to revision and may not be applicable to all undeveloped locations. Play data should not be relied on as an estimate or evaluation of reserves or resources associated with the Company's properties and readers are referred to the McDaniel Report and to the Company's annual information form for the year ended December 31, 2022, which is available on SEDAR+ at www.sedarplus.ca or at www.paramountres.com, for reserves information respecting the Company.

Undeveloped Locations

This presentation contains information respecting Paramount’s internal estimate of future potential undeveloped locations at various properties. The future potential undeveloped location information contained in this presentation represents gross locations and was prepared effective November 1, 2023 by internal qualified reserves evaluators from Paramount. The undeveloped locations referred to in this presentation 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 additional 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 additional oil and natural gas reserves or production. This below table references the future potential undeveloped locations assigned reserves in the McDaniel Report solely to provide the reader with additional information concerning internally estimated future potential undeveloped locations as compared to locations assigned reserves in the McDaniel Report. The comparability of internally estimated future potential undeveloped locations to locations assigned in the McDaniel Report is limited due to differing assumptions and differing effective dates. There is no guarantee that any internally estimated future potential development location will be included and assigned reserves in any future reserves report prepared for the Company. The table below sets out Paramount's internal estimate of future potential undeveloped locations for each applicable property as at November 1, 2023 and the number of undeveloped locations that were assigned reserves in the McDaniel Report as at December 31, 2022.

	Karr (Middle Montney)	Wapiti	Kaybob North Duvernay	Kaybob North Montney Oil	Ante Creek Montney Oil	Willesden Green Duvernay
Referenced Undeveloped Locations	209	235	150	26	99	713
Locations Assigned Reserves in the McDaniel Report	164	155	57	0	0	70

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