Corporate Presentation

Paramount resources ltd.

January 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 January 11, 2023. Certain internally estimated play data contained in this presentation was prepared effective November 1, 2022. 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 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 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, tight oil and light and medium crude oil.

Corporate Overview

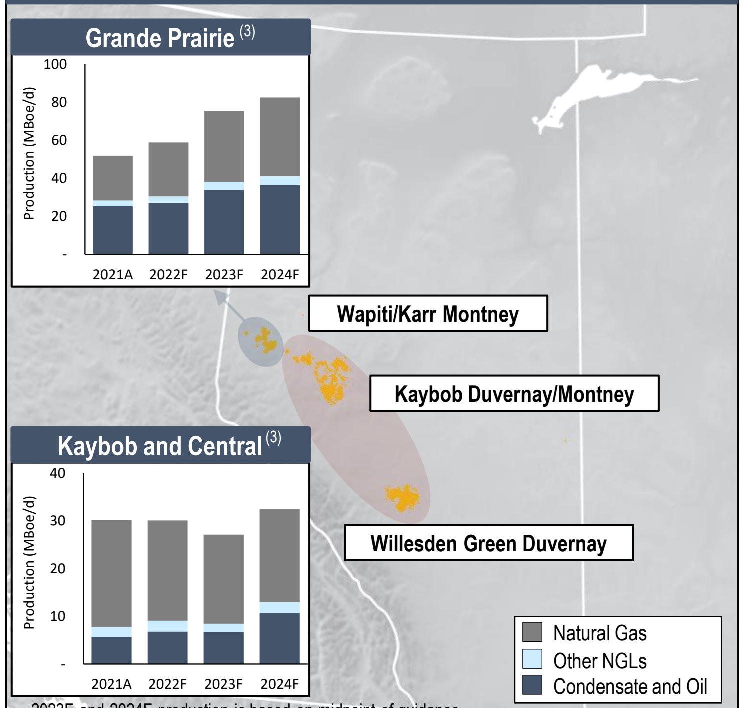
Paramount has significant land positions in the most liquids-rich areas of the prolific Montney and Duvernay resource plays

- Founded in 1976 (IPO'd in 1978)
- Significant insider ownership (~47%) (1)
- TP Reserves: 339 MMBoe (49% liquids) (2)
- P+P Reserves: 662 MMBoe (49% liquids) (2)
- 4Q22F Production: ~97,500 Boe/d (45% liquids) (3)
- Monthly dividend increased to $0.125/share in Nov. 2022
- Special dividend of $1.00/share in Jan. 2023 (4)

Market Snapshot (TSX-POU)	
Shares Outstanding (MM)	142.8
Market Capitalization ($MM) (5)	~$4,200
Bank Debt ($MM) (6)	$0
Investments in Securities at Sep. 30, 2022 ($MM)	~$450
Monthly Dividend ($/share | Annualized Yield) (7)	$0.125 | 5.0%

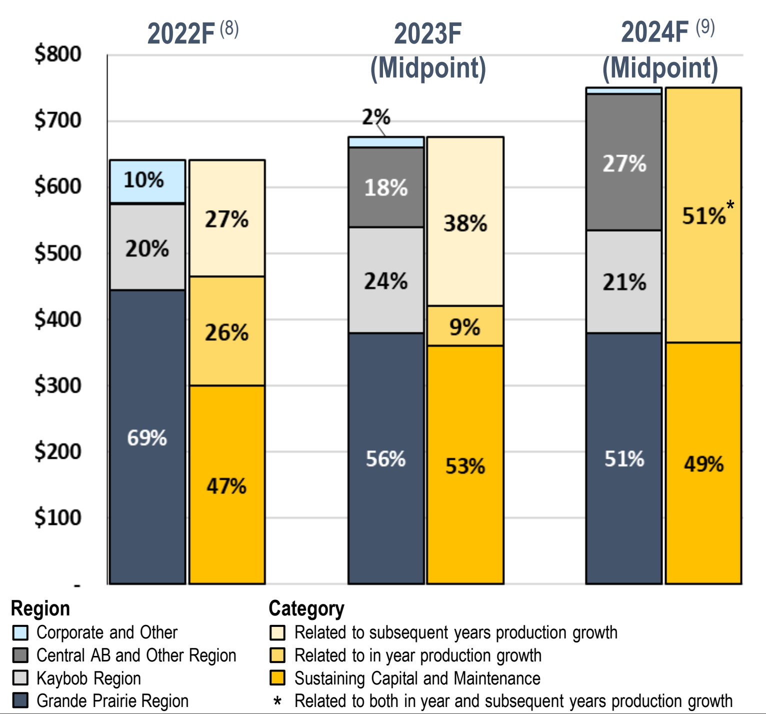
Guidance Summary	2022F(8)	2023F	2024F(9)
Production (MBoe/d) (% Liquids)	~89(3) (45%)	100-105 (45%)	110-120 (47%)
CapEx ($MM)	~$640	$650-$700	$700-$800
ARO ($MM)	~$35	$55	$40
Net Debt/AFF (10)	<0.3x	na	na

Focus Areas

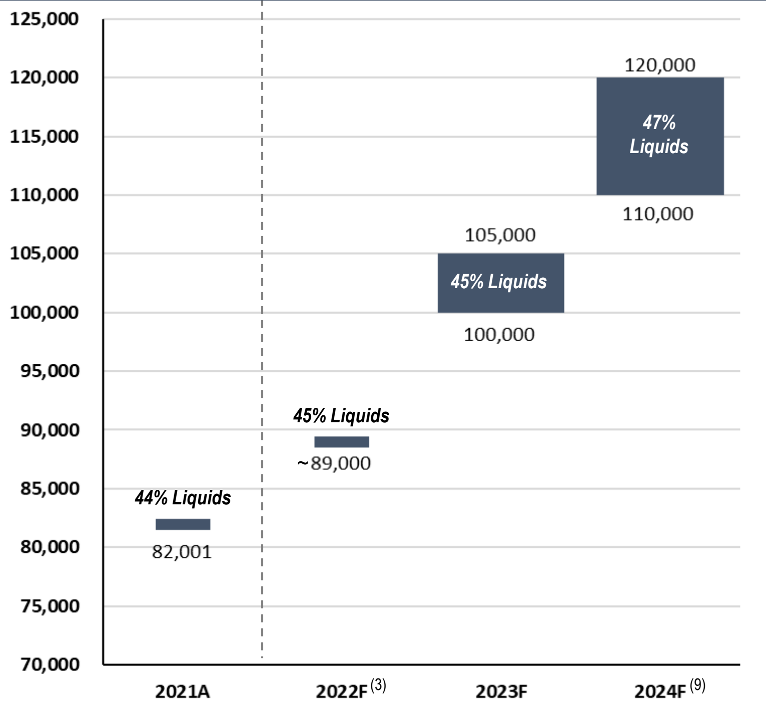


2023F and 2024F production is based on midpoint of guidance

Capital Expenditure Outlook ($MM)



Production Outlook Range (Boe/d)



(1) Consists of Common Shares held by directors, officers and other insiders. (2) See Advisories Appendix – Reserves Data. (3) The stated estimates of sales volumes for the fourth quarter of 2022 and annual 2022 are based on preliminary field estimates and are subject to change. See Advisories Appendix – Forward Looking Information. (4) January 18, 2023 record date, January 25, 2023 payment date. (5) 142.8MM shares at $29.72/share. (6) As of January 11, 2023. (7) Annualized yield is obtained by dividing 12 months of the stated monthly dividend by a share price of $29.72. (8) The stated estimates of 2022 capital expenditures and abandonment and reclamation expenditures are unaudited, preliminary and subject to change. See Advisories Appendix – Forward Looking Information. (9) 2024 amounts are current expectations based on preliminary planning and current market conditions and are subject to change. (10) Net debt and net debt to adjusted funds flow are capital management measures used by Paramount. See Advisories Appendix – Specified Financial Measures.

Delivering on Free Cash Flow Priorities

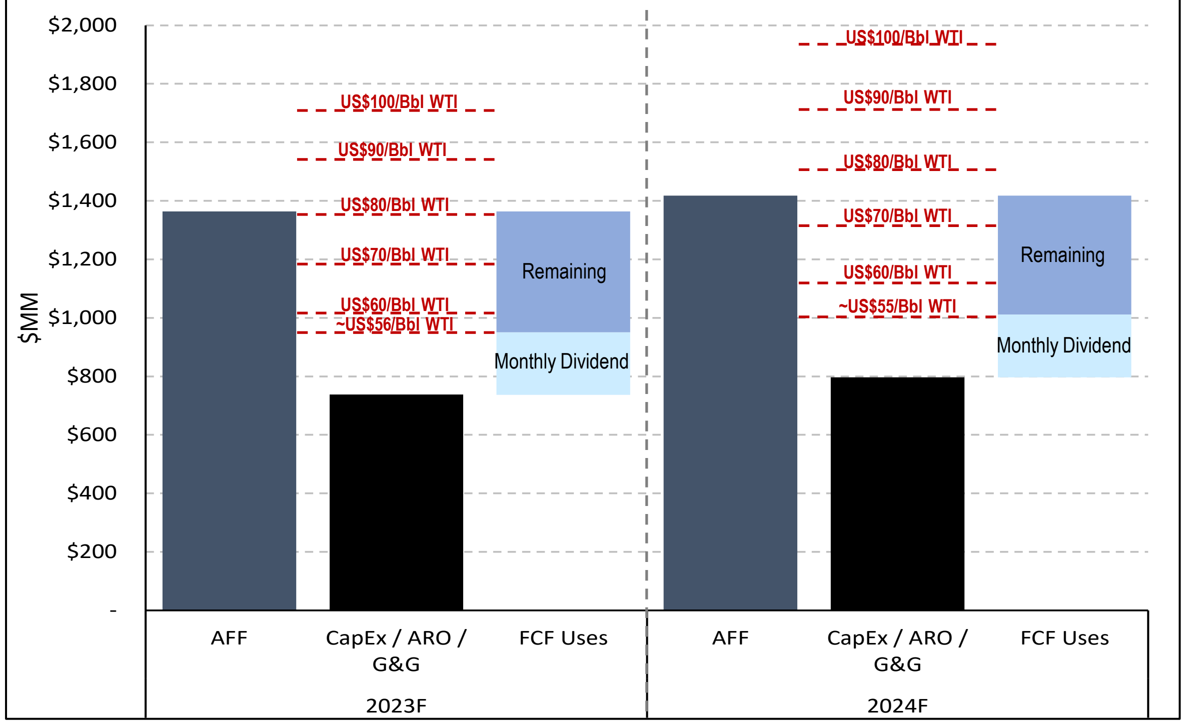
With no bank debt currently outstanding, Paramount is ideally positioned to deliver on FCF priorities

- The Company's free cash flow priorities continue to be the delivery of superior shareholder returns, while maintaining a strong balance sheet, through a combination of:
  - Dividends, including the flexibility for incremental returns through further special dividends
  - Opportunistic share buybacks
  - Investments in growth opportunities
- Cumulative $2.46/share cash dividends from July 2021 to January 2023
  - Increased regular monthly dividend four times since inception
  - Special cash dividend of $1.00/share in January 2023 (1)

Illustrative Adjusted Funds Flow ($MM) (2)(3)		
	2023F	**2024F**
Free Cash Flow ("FCF") Guidance	~$630	~$620
Midpoint of CapEx Guidance	~$675	~$750
ARO Guidance	~$55	~$40
Geological & Geophysical Expense	~$7	~$7
Illustrative Adjusted Funds Flow ("AFF")	**~$1,365**	**~$1,420**
Year-over-Year Growth		
Production Growth	**15%**	**12%**
AFF Growth	**16%**	**4%**
Free Cash Flow Growth	**26%**	**(2)%**

- Closed the Kaybob disposition in January for net cash proceeds of $370 million, eliminating bank debt
- The Company's 2023 capital program and regular monthly dividend would remain fully funded at the midpoint down to an average WTI price of ~US$56/Bbl in 2023 (4)

Illustrative AFF and FCF Estimates (2)(3)

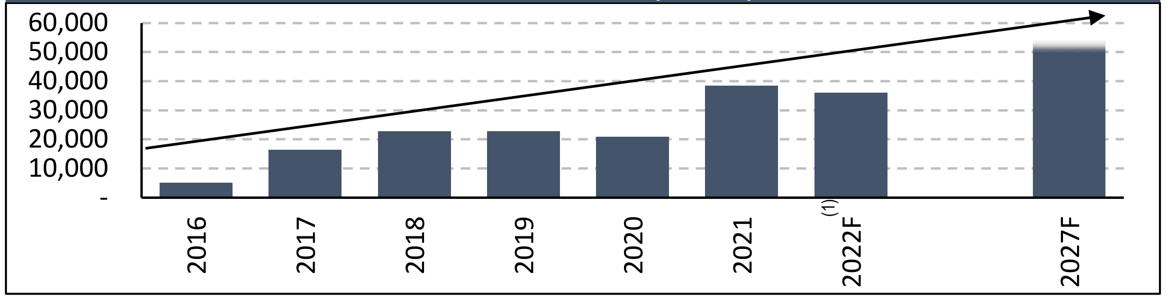


(1) January 18, 2023 record date, January 25, 2023 payment date. (2) See Advisories Appendix – Forward Looking Information for a breakdown of the pricing, cost, expenditure and other assumptions on which the estimates are based. (3) Free cash flow and adjusted funds flow are capital management measures used by Paramount. See Advisories Appendix – Specified Financial Measures. (4) Assuming no changes to the other forecast assumptions for 2023.

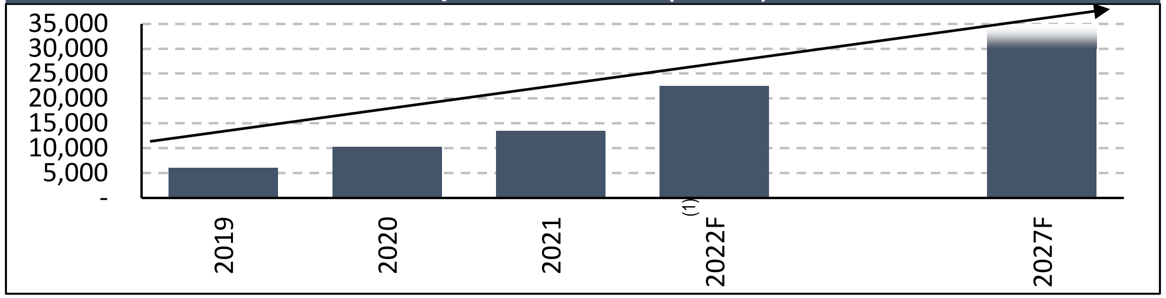
Building Sustainable Free Cash Flow for the Long-Term

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

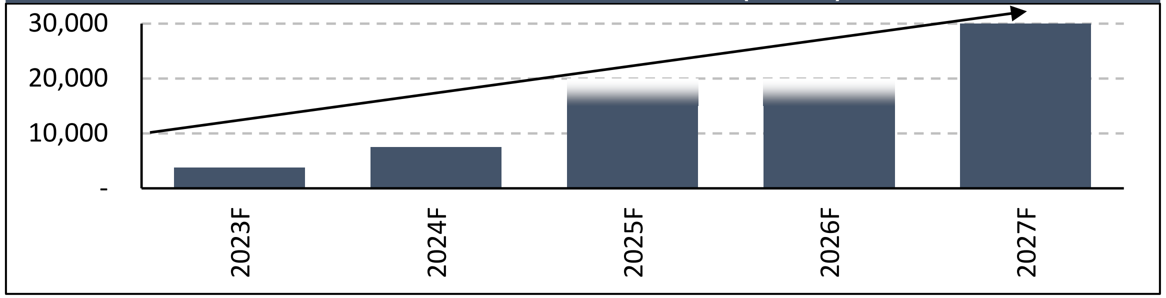
Karr Production (Boe/d)



Wapiti Production (Boe/d)



Willesden Green Production (Boe/d)



- Paramount has a demonstrated track record of assembling material positions in key resource plays and solving for plateau production levels that can be sustained for 15+ years
  - **Karr:** Began assembling land position in 2005; methodically grew production from zero to ~40,000 Boe/d, with plans to grow to ~50,000 Boe/d
  - **Wapiti:** Acquired position through the 2017 acquisition of Apache Canada and grew production from near zero to ~30,000+ Boe/d
  - **Willesden Green Duvernay:** Current land position acquired over multiple years and multiple transactions with current plans to grow production to ~30,000 Boe/d by 2027 and to over 50,000 Boe/d thereafter

Highlights of 5-Year Outlook	
Annual Average Capital Expenditures	~$750 MM
Compound Annual Production Growth Rate (2022-2027)	~10%
Cumulative Free Cash Flow (2)	**~$3.9 Bn (~27/sh.)** (3)

- The Company does not forecast cash tax in its five-year outlook until 2026 (4)

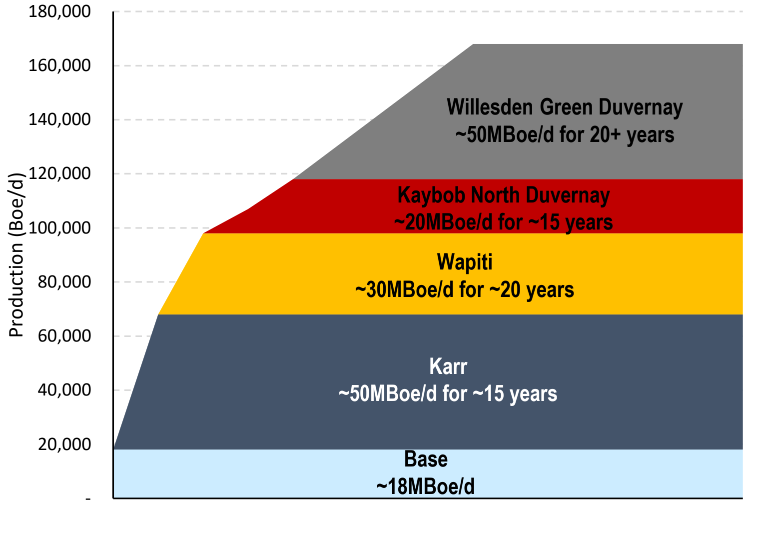
(1) Estimated 2022 sales volumes are based on preliminary field estimates and are subject to change. **(2)** The five-year outlook is based on preliminary planning and current market conditions and is subject to change. The stated anticipated cumulative free cash flow is based on the following assumptions: (i) the stated annual capital expenditures and compound annual production growth; (ii) approximately $55 million in 2023 and $40 million thereafter in average annual abandonment and reclamation costs, (iii) approximately $7 million in annual geological and geophysical expenses, (iv) 2023 realized pricing of $63.00/Boe (US$80.00/Bbl WTI, US$5.00/MMBtu NYMEX, $4.74/GJ AECO) and thereafter commodity prices of US$75.00/Bbl WTI, US$4.50/MMBtu NYMEX and $4.27/GJ AECO, (v) a 2023 $US/$CAD exchange rate of $0.730 and thereafter a $US/$CAD exchange rate of $0.735 and (vi) internal management estimates of future royalties, operating costs, transportation and processing costs and, beginning in 2026, cash taxes. **(3)** Based on 142.8 million outstanding class A Common Shares as at January 11, 2023. **(4)** See the Advisories Appendix – Forward-Looking Information for a description of certain of the key underlying assumptions.

Prudent Development of Inventory-Rich Opportunity Set

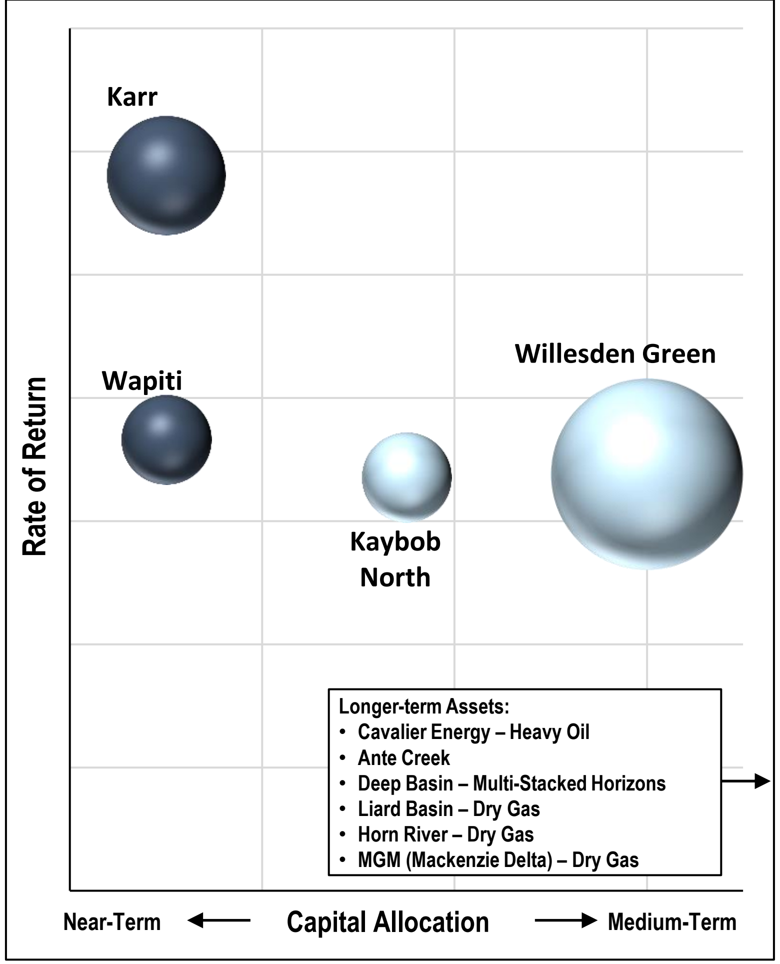
Paramount continues to allocate capital to its highest risk-adjusted return opportunities while maintaining balance sheet strength

- 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 potential plateau production that can be sustained for 15 to 20 years based on management estimates of full field development location count

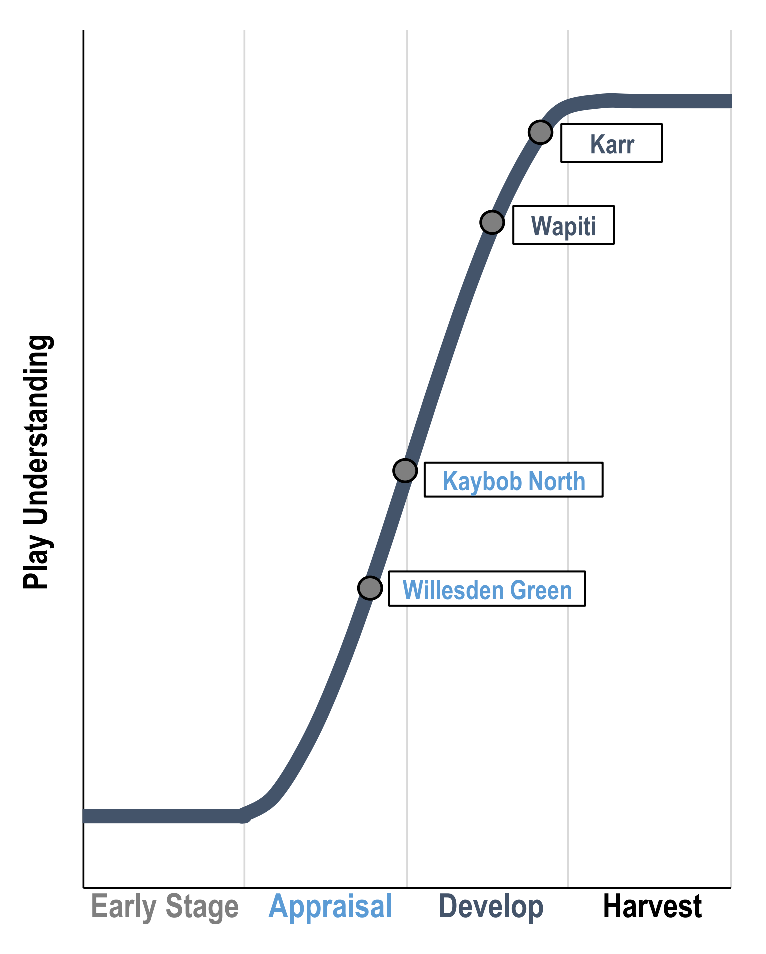
Potential Plateau Production (1)



Significant Asset Optionality & Value (2)



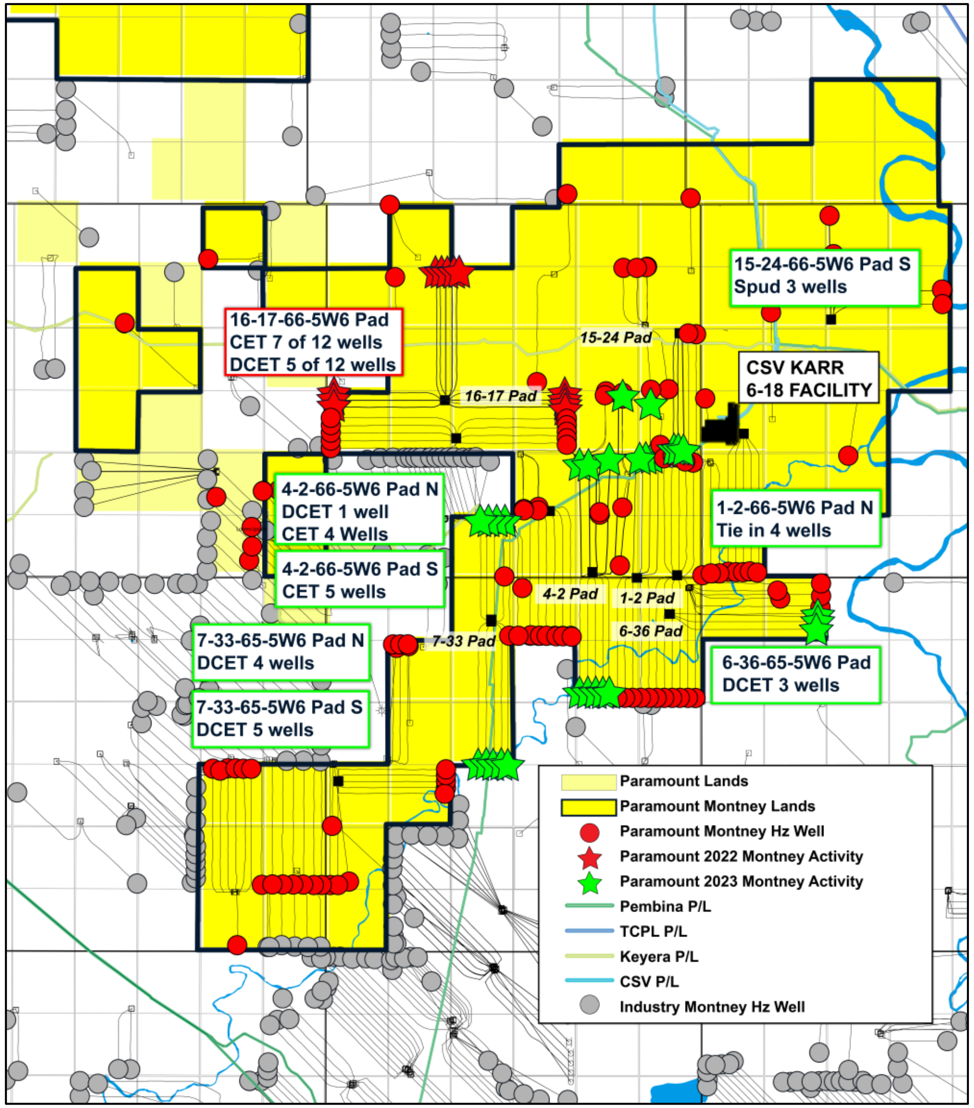
Stage of Development



(1) Based on management estimates of play data and undeveloped drilling locations as described on slides 7, 8, 10, 11, 14 and 15. See Advisories Appendix – Play Data and Undeveloped Locations. **(2)** Paramount's expectation as of November 1, 2022 of rate of return vs. total value assuming full field development on a relative basis. Total value only includes remaining inventory.

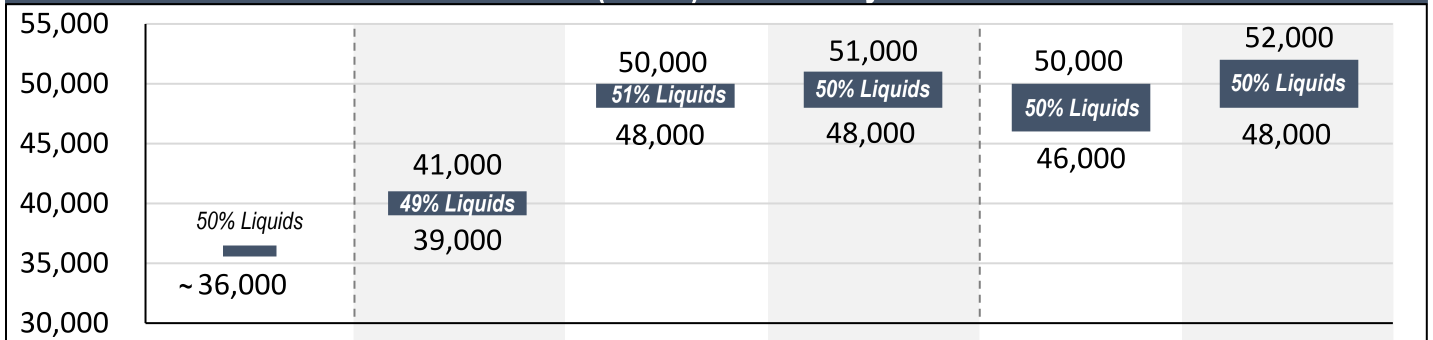
Karr Activity and Production

Production from Paramount's flagship asset at Karr is expected to grow to ~50,000 Boe/d in the second half of 2023



- Actively began development in 2016 with 86 wells brought onstream to the end of September 2022
- 2023 activities include 13 drills, 22 completions and 22 wells to be brought onstream
- Bringing onstream additional gas lift compression to support liquids production and facilitate growth to a new plateau rate of ~50,000 Boe/d
- Management high-graded undeveloped location count of 244 wells (Middle Montney development)
  - ~59% assigned reserves as at December 31, 2021 (1)

Production (Boe/d) and Activity Outlook



2022F (2)	1Q23F	2Q23F	2H23F	2023F	2024F
• Brought onstream 7 wells at the 16-17 pad in 1Q22 and the remaining 5 in 3Q22 • Three-week full field outage in 2Q22 • The 4-well 1-2N pad was drilled and largely completed by 4Q22 • 9 of 10 wells drilled by 4Q22 at the 4-2 N and 4-2 S pads • 4Q22 infrastructure downtime	• Bring onstream all 4 wells on the 1-2N pad • Complete all 10 wells on the 4-2 N and 4-2 S pads • Commence drilling operations at the 5-well 7-33 S pad	• Bring onstream all 10 wells from the 4-2N and 4-2 S pads • Commence completion operations at the 7-33 S pad • Commence drilling operations at the 3-well 6-36 pad • Infrastructure optimization complete	• Bring onstream all 5 wells at the 7-33S pad by 3Q23 • Complete, tie-in and bring on production all 3 wells at the 6-36 pad • Drill, complete and tie-in the 4-well 7-33 N pad • Commence the drilling of the 3-well 15-24 pad in 4Q23	• Continue infrastructure optimization to grow production to approximately 50,000 Boe/d • Drill 13 wells • Bring onstream 22 wells	• Maintain targeted plateau production of ~50,000 Boe/d by bringing onstream ~18-23 wells

(1) See Advisories Appendix – Undeveloped Locations. (2) Annual 2022 sales volumes are based on preliminary field estimates and are subject to change. See Advisories Appendix – Forward Looking Information.

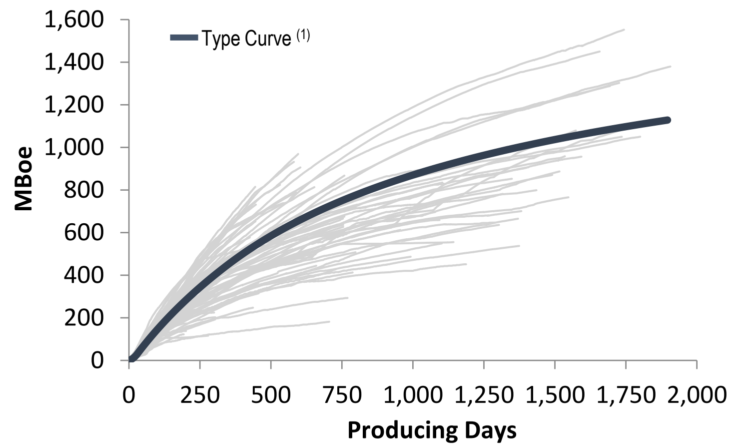
Karr Performance and Recent Highlights

Paramount's Montney wells at Karr continue to perform strongly

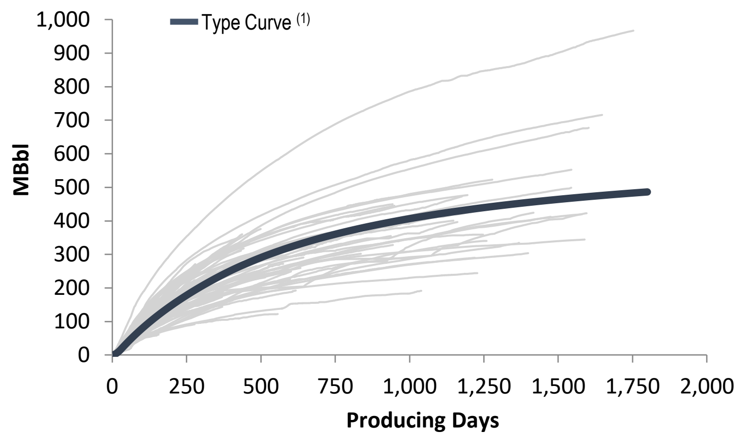
Recent Highlights

- Brought onstream the remaining five wells on the twelve-well 16-17 pad
- The Company's planned development activities are expected to grow production to a new plateau range of ~50,000 Boe/d in 2023
  - Continued debottlenecking initiatives to support higher production in 2023
- Completion operations at the four-well 1-2 North pad commenced in the fourth quarter. All four wells are expected to come onstream in the first quarter of 2023
- Nine of ten wells were drilled in the fourth quarter at the 4-2 North and 4-2 South pads
- Unexpected infrastructure downtime negatively impacted fourth quarter 2022 production volumes. Subsequent repairs have fully restored production capacity

Cumulative Boe – Karr Wells



Cumulative NGLs – Karr Wells



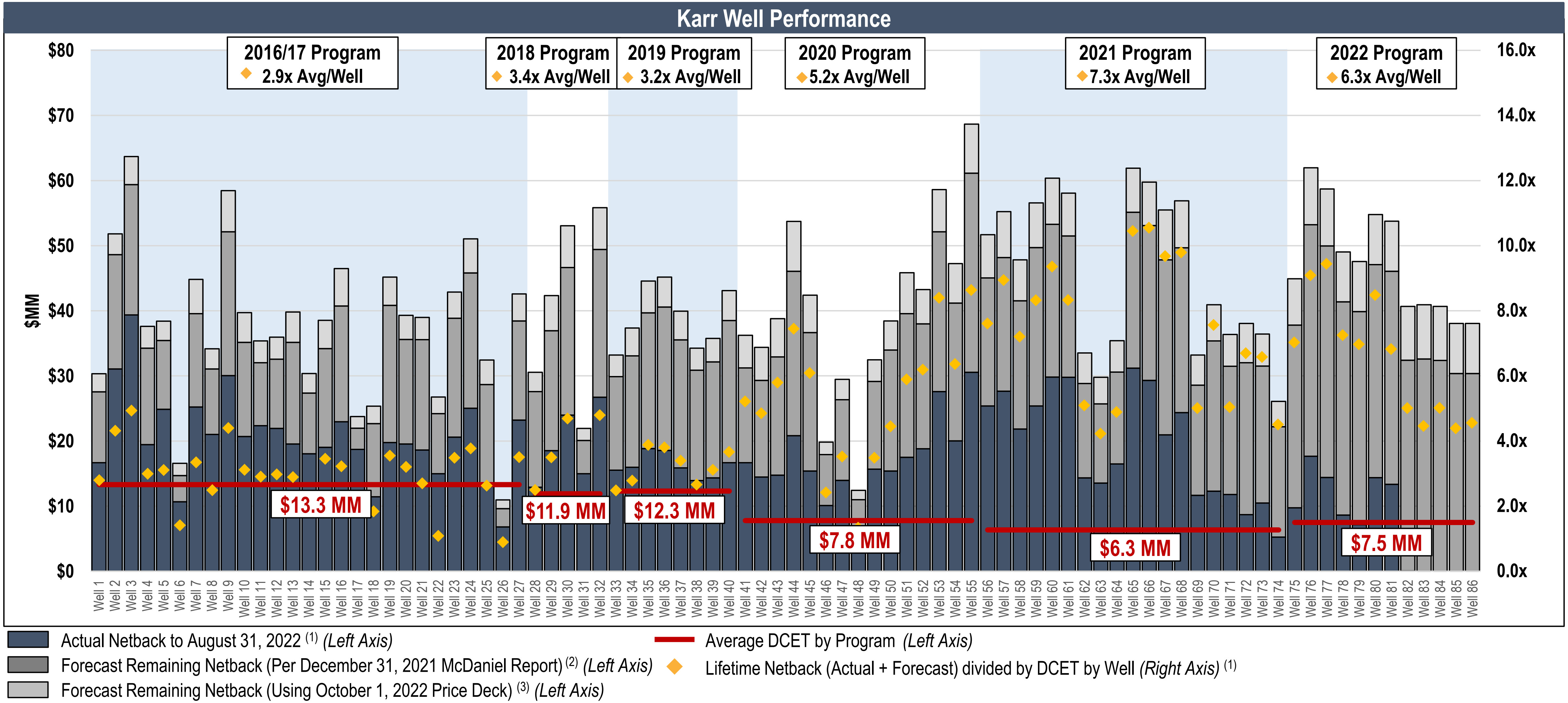
Play Data – 3,000m Avg. Lateral Length [(2)]	
IP 365 *(Boe/d)*	1,276
IP 365 CGR *(Bbl/MMcf)*	177
Sales Volume *(MBoe)*	1,642
Average CGR *(Bbl/MMcf)*	112
Sales Gas Volume *(Bcf)*	5.6
Sales Condensate *(MBbl)*	586
DCET *($MM)*	$8.7

- Highly productive liquids-rich wells drive industry-leading half-cycle economics
- Estimated per well sales volumes ~1.6 MMBoe
  - Implied capital efficiency of ~$6,800/Boe/d (3)
- Grande Prairie PDP F&D costs were $6.53/Boe in 2021, down ~25% from 2020 (3)
  - Results in a recycle ratio of 6.9x when using Karr's Q3 2022 netback of $45.33/Boe

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 10 percent and liquids sales volumes are lower by approximately 6 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.

Karr Performance

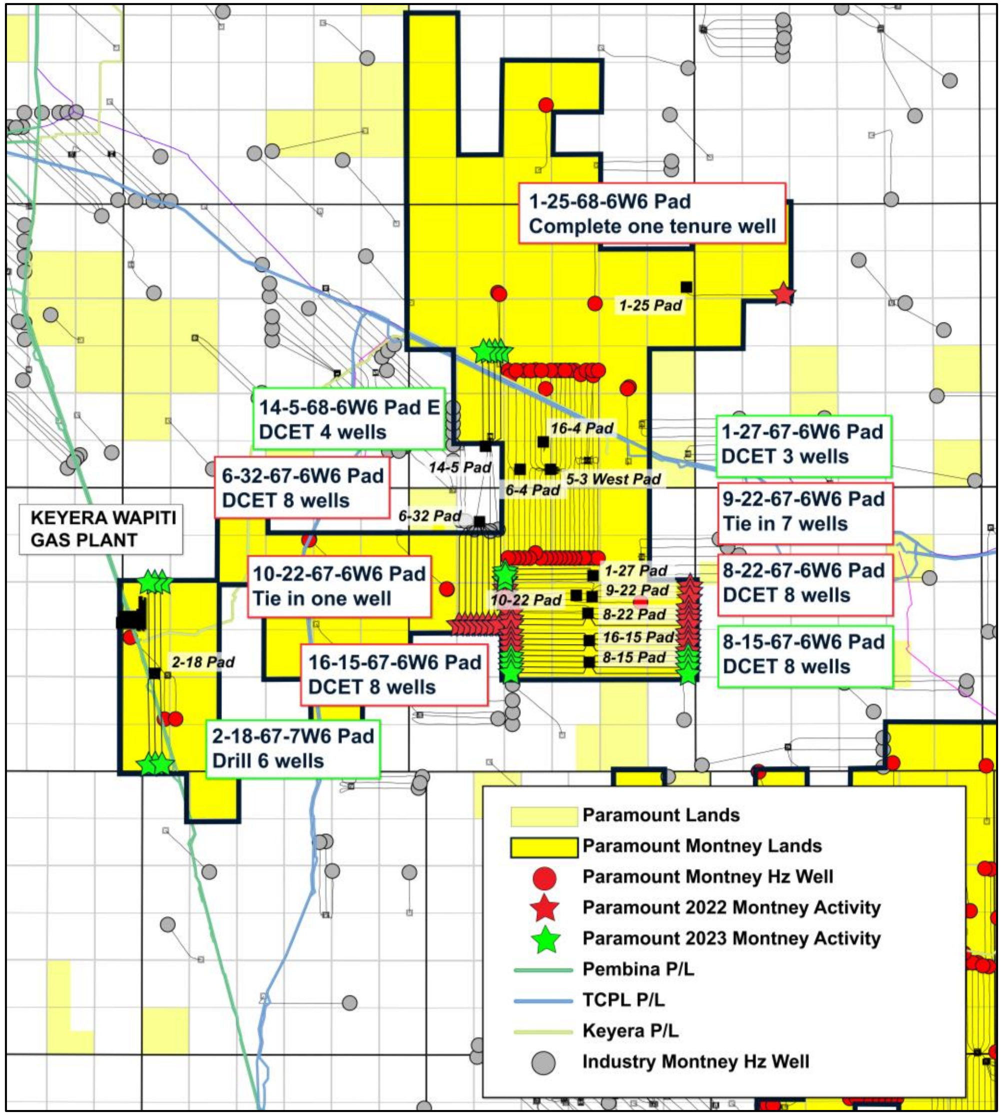
Wells exhibit strong returns and quick payouts



(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. **(3)** Amounts represent undiscounted forecast total proved plus probable netback over the remaining life of each well as calculated by management consistent with the forecasts, assumptions and methodology in the McDaniel Report but utilizing an updated price forecast that is the average of the October 1, 2022 price forecasts for McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Ltd.

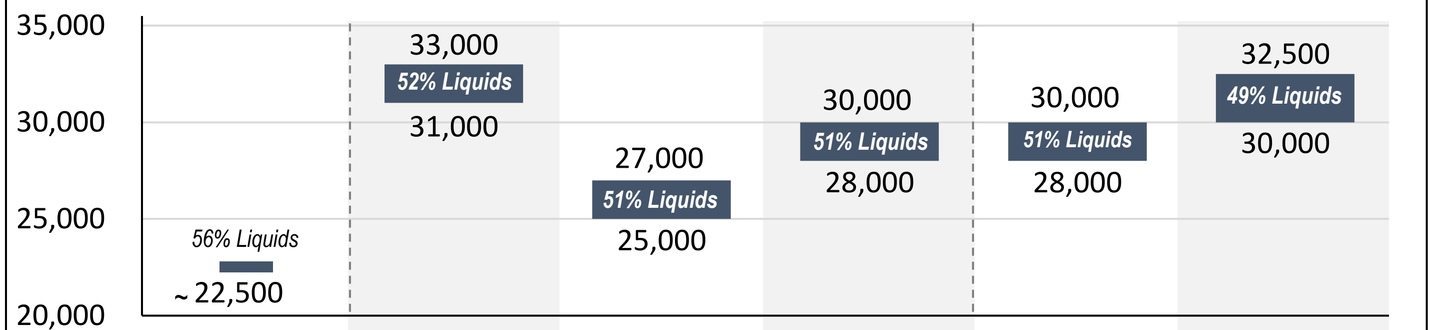
Wapiti Activity and Production

Achieved targeted plateau production of ~30,000 Boe/d in September one quarter ahead of schedule



- Development commenced in 2018 with 58 wells brought onstream to the end of September 2022
- 2023 activity includes 21 drills, 15 completions and 13 wells to be brought onstream
- Takeaway capacity in place to support Montney production growth
- Plateau production of ~30,000 Boe/d achieved in September 2022
- Management full field development location count of 229 wells
  - ~67% assigned reserves as at December 31, 2021 (1)
  - Supports 20+ years of production

Production (Boe/d) and Activity Outlook



2022F (2)
- Brought onstream 4 wells at the 9-22 pad in 1Q22 and all 16 wells at the 8-22 and 6-32 pads over 2Q22 and 3Q22
- 9-day turnaround plus ~3 weeks of unplanned outages in 2Q22
- 6 of 8 wells at the 16-15 pad onstream in 4Q22
- Commenced drilling the 3-well 1-27 pad in 4Q22
- Unplanned outage and curtailments in 4Q22

1Q23F
- Bring onstream the remaining 2 wells at the 8-well 16-15 pad
- Finish drilling and commence completions at the 3-well 1-27 pad
- Commence the drilling of the 8-well 8-15 pad

2Q23F
- Bring onstream all 3 wells at the 1-27 pad
- Commence completion operations at the 8-15 pad
- Commence drilling operations at the 4-well 14-5 E pad
- Planned 10-day outage for third-party infrastructure work

2H23F
- Tie-in and bring onstream all 8 wells at the 8-15 pad in 3Q23
- Complete and tie-in all 4 wells at the 14-5 E pad
- Drill the 6-well 2-28 pad by 4Q23

2023F
- Maintain plateau production by drilling 21 wells and bringing onstream 13 wells

2024F
- Maintain plateau production by bringing onstream ~15-20 wells

(1) See Advisories Appendix – Undeveloped Locations. **(2)** Annual 2022 sales volumes are based on preliminary field estimates and are subject to change. See Advisories Appendix – Forward Looking Information.

Wapiti Performance and Recent Highlights

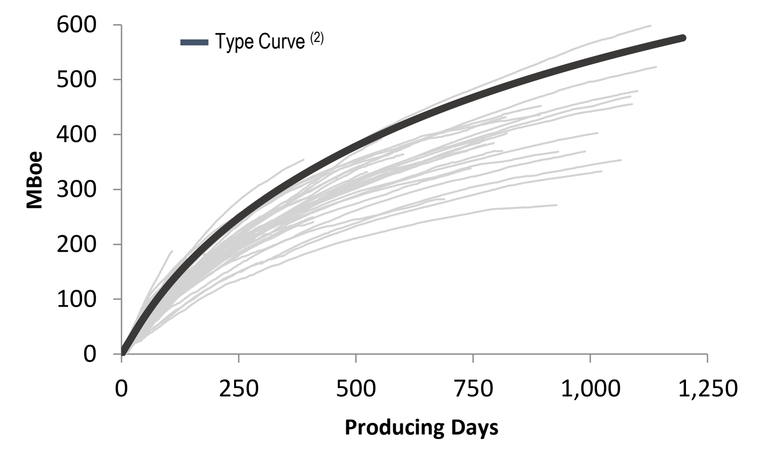
Lower cost monobores and the implementation of an optimized well completion have further enhanced Wapiti economics

Paramount resources ltd.

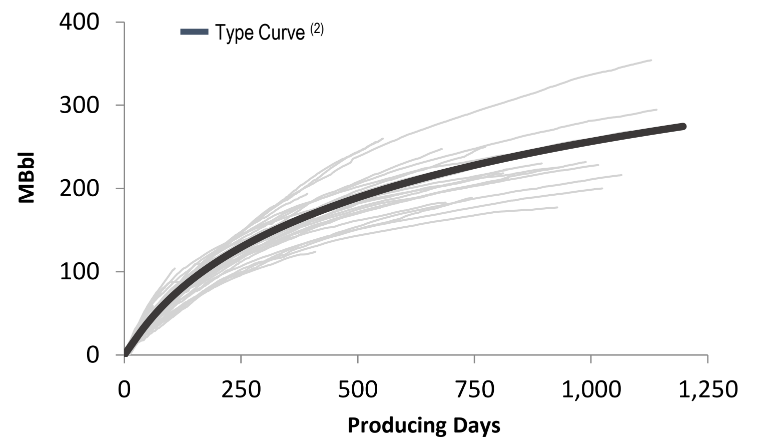
Recent Highlights

- Record monthly sales volumes of 30,589 Boe/d (54% liquids) were achieved in September
- The eight-well 6-32 pad was brought onstream in Q3 2022
  - DCET costs averaged $7.5 million per well
  - Averaged 1,722 Boe/d (4.4 MMcf/d of shale gas and 995 Bbl/d of NGLs) of peak 30-day wellhead production per well with an average CGR of 228 Bbl/MMcf (1)
- The 6-32 and 8-22 pads have exhibited higher natural gas contribution with similar liquids volumes compared to previous Wapiti wells, contributing to the achievement of plateau production ahead of schedule
- Unit operating costs continue to decrease as production ramps up, further enhancing per unit netbacks

Cumulative Boe – Wapiti Wells



Cumulative NGLs – Wapiti Wells



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

IP 365 *(Boe/d)*	847
IP 365 CGR *(Bbl/MMcf)*	194
Sales Volume *(MBoe)*	1,029
Average CGR *(Bbl/MMcf)*	172
Sales Gas Volume *(Bcf)*	3.0
Sales Condensate *(MBbl)*	481
DCET *($MM)*	$8.3

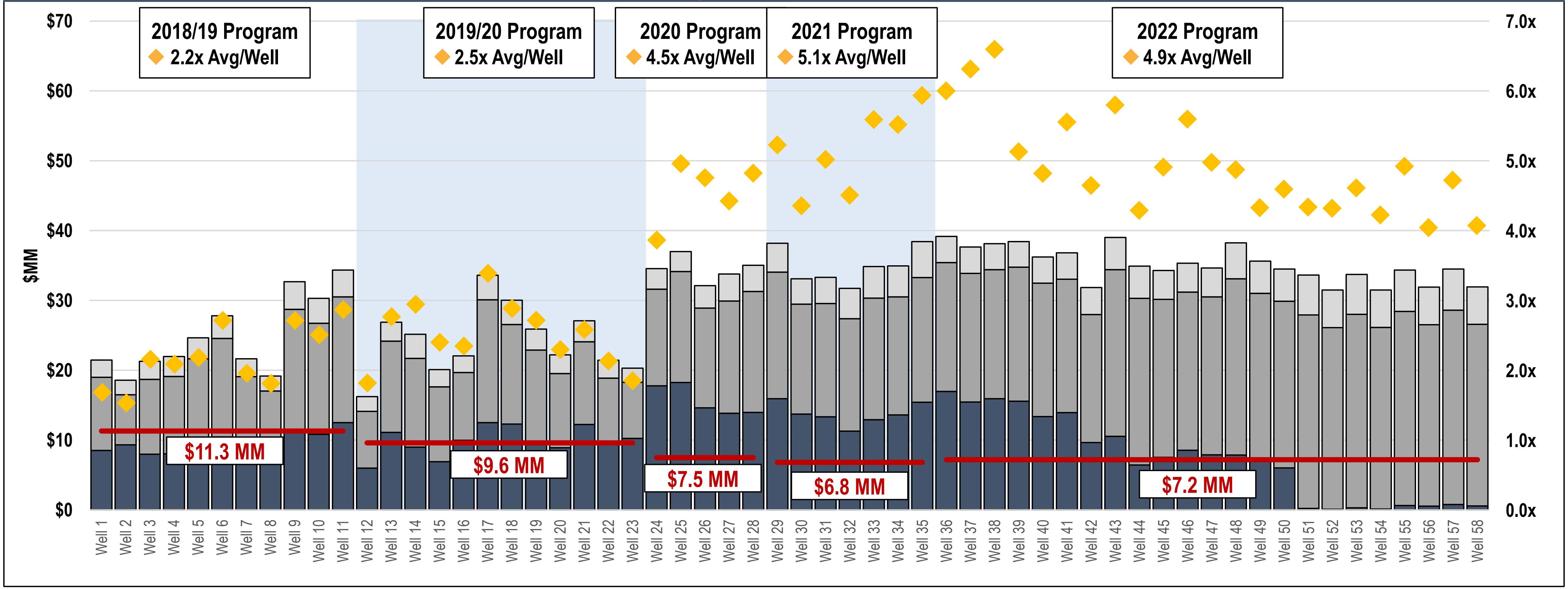
- Implied capital efficiency of ~$9,800/Boe/d (4)
- Grande Prairie PDP F&D costs were $6.53/Boe in 2021, down ~25% from 2020 (4)
  - Results in a recycle ratio of 8.0x when using Wapiti's Q3 2022 netback of $52.33/Boe

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 11 percent and liquids sales volumes are lower by approximately 2 percent due to shrinkage. Excludes days 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 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)** Production measured at the wellhead. Natural gas sales volumes are lower by approximately 11 percent and wellhead liquids sales volumes are lower by approximately 2 percent due to shrinkage, under normalized operations. **(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. 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

With improved performance, Wapiti wells are generating strong returns on invested capital

Wapiti Well Performance



Actual Netback to August 31, 2022 (1) *(Left Axis)*

Forecast Remaining Netback (Per December 31, 2021 McDaniel Report) (2) *(Left Axis)*

Forecast Remaining Netback (Using October 1, 2022 Price Deck) (3) *(Left Axis)*

Average DCET by Program *(Left Axis)*

Lifetime Netback (Actual + Forecast) divided by DCET by Well *(Right Axis)* (1)

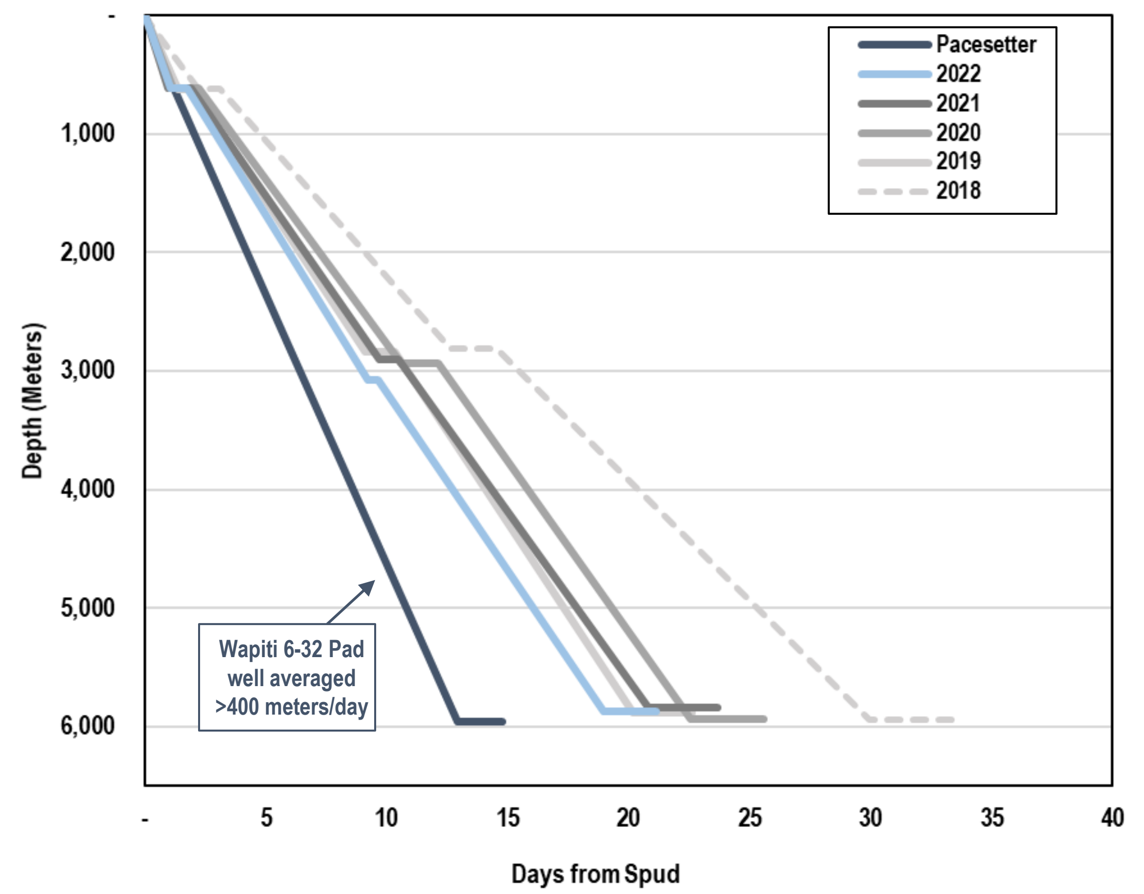
(1) Netback is a non-GAAP financial measure. Lifetime Netback divided by DCET by Well is a non-GAAP ratio. See Advisories Appendix – Specified Financial Measures. **(2)** See Advisories Appendix – Reserves Data. Amounts represent undiscounted forecast proved plus probable netback over the remaining life of each well as included in the McDaniel Report. **(3)** Amounts represent undiscounted forecast total proved plus probable netback over the remaining life of each well as calculated by management consistent with the forecasts, assumptions and methodology in the McDaniel Report but utilizing an updated price forecast that is the average of the October 1, 2022 price forecasts for McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Ltd.

Grande Prairie Capital Efficiencies

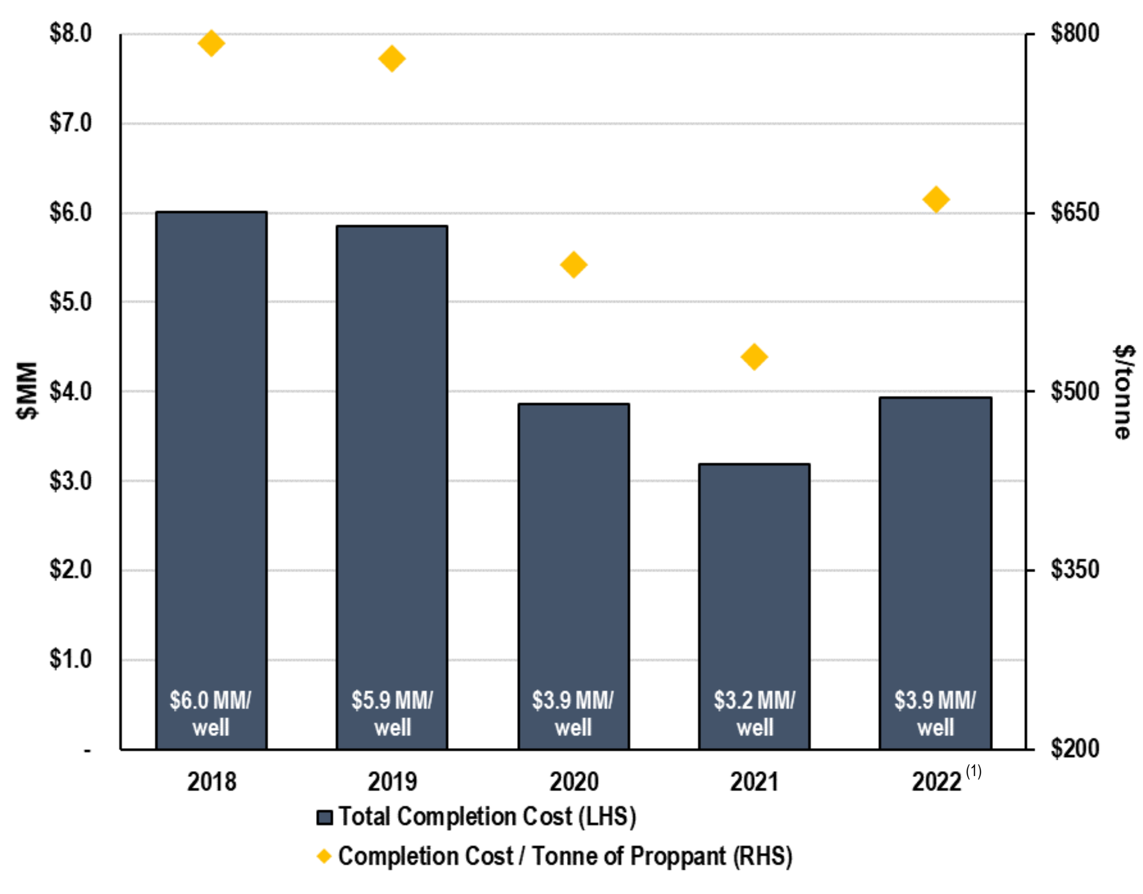
Paramount remains relentlessly focused on continuous improvement

- The Company continues to strive for further efficiencies while maintaining its focus on safety, integrity and long-term productivity of its assets
- Efforts to offset inflationary pressures on DCET costs include optimization of drilling efficiencies through bit/motor/mud selection and enhanced wellbore design

Grande Prairie Region Average Drilling Days



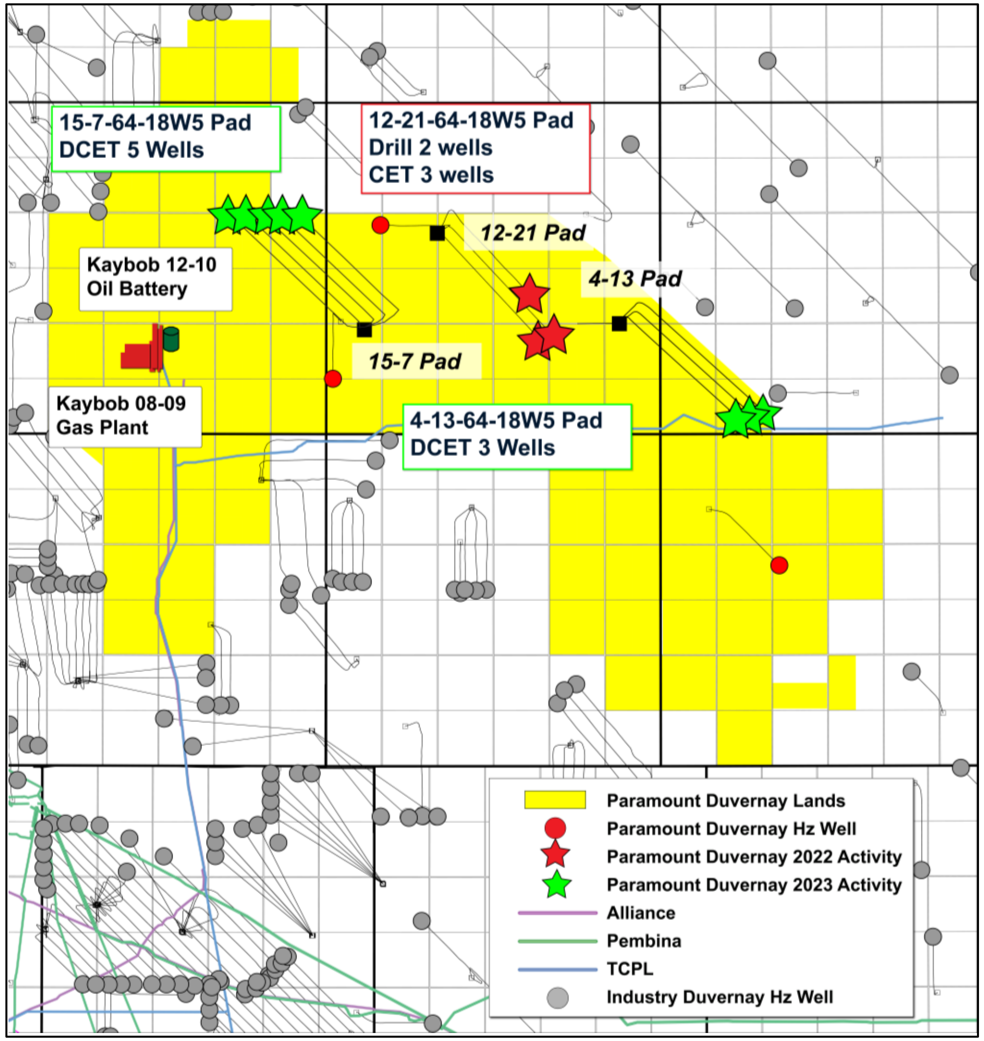
Grande Prairie Region Average Completion Costs



(1) To September 30, 2022.

Kaybob North Duvernay Overview

The Kaybob North Duvernay play will contribute to the next material wedge of production growth over the coming years



- Eight wells across two pads are expected to be drilled, completed and brought onstream in 2023
- Paramount has ownership in strategic facilities and infrastructure including the 8-9 Gas Plant and 12-10 Oil Battery
- Paramount owns and operates a crude oil terminal capable of capturing incremental value in price differentials with capacity to handle future growth
- The Company brought onstream the three-well 12-21 pad in the third quarter of 2022
  - Two of the wells were drilled to a total lateral length of ~4,200 meters, representing the longest laterals drilled by Paramount in the Kaybob Region
  - All in DCET costs averaged $11.7 million per well
  - Initial production results are encouraging despite being choked due to infrastructure capacity constraints, averaging 862 Boe/d (0.8 MMcf/d of shale gas and 732 Bbl/d of NGLs) of peak 30-day wellhead production per well with an average CGR of 933 Bbl/MMcf (1)

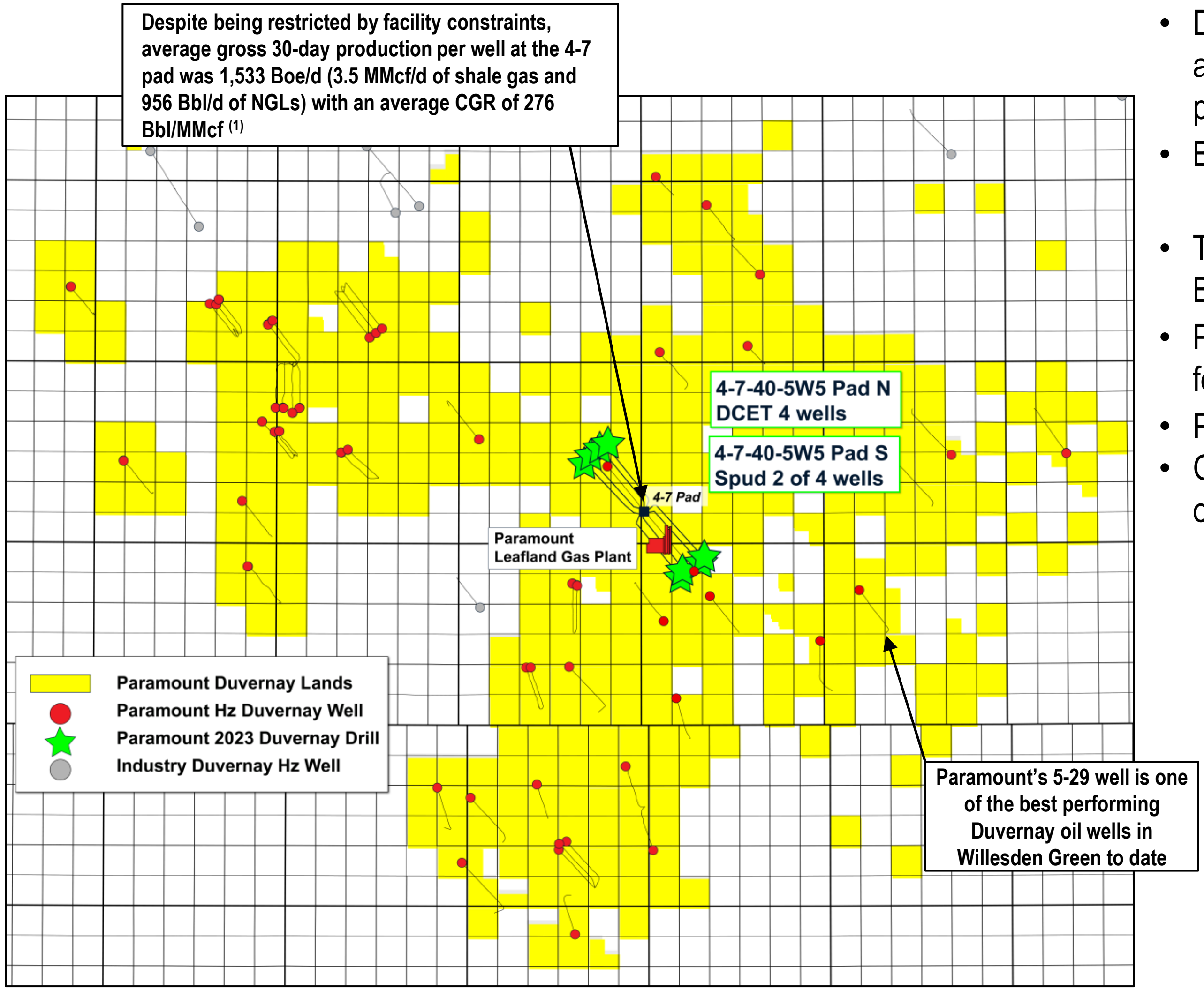
Play Data – 4,200m Avg. Lateral Length (2)	
IP 365 *(Boe/d)*	624
IP 365 CGR *(Bbl/MMcf)*	527
Sales Volume *(MBoe)*	951
Average CGR *(Bbl/MMcf)*	380
Sales Gas Volume *(Bcf)*	1.7
Sales Condensate *(MBbl)*	625
DCET *($MM)*	$11.8

- Targeting plateau production of ~20,000 Boe/d
- 148 full field development locations (~24% assigned reserves as at December 31, 2021) based on ~320m inter-well spacing and lateral length of 4,200m (3)
- Implied capital efficiency of ~$18,900/Boe/d (4)
- Paramount expects to realize capital cost efficiencies in the Kaybob North Duvernay as more wells are drilled

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 20 percent and liquids sales volumes are lower by approximately 9 percent due to shrinkage. Excludes days 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 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. **(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 recently consolidated ~250,000 net acre core Duvernay area



- Development plans include the staged construction of incremental processing capacity across multiple facilities with total capacity of approximately 100 MMcf/d of raw gas processing and 20,000 Bbl/d of liquids handling available by 2027
- Budgeting ~$125 million in 2023 and ~$210 million in 2024 (mid-point)
  - >50% allocated to facility and associated infrastructure construction
- Two four-well pads are planned for 2023, increasing mid-point production from 3,750 Boe/d (47% liquids) in 2023 to 7,500 Boe/d (59% liquids) in 2024
- Production is expected to average between 15,000 Boe/d and 20,000 Boe/d (59% liquids) for each of 2025 and 2026
- Plans include the development of the eastern oil window near the end of the 5-year plan
- Over 600 internally high-graded drilling inventory supports targeted plateau production of over 50,000 Boe/d that can be sustained for over 20 years (2)

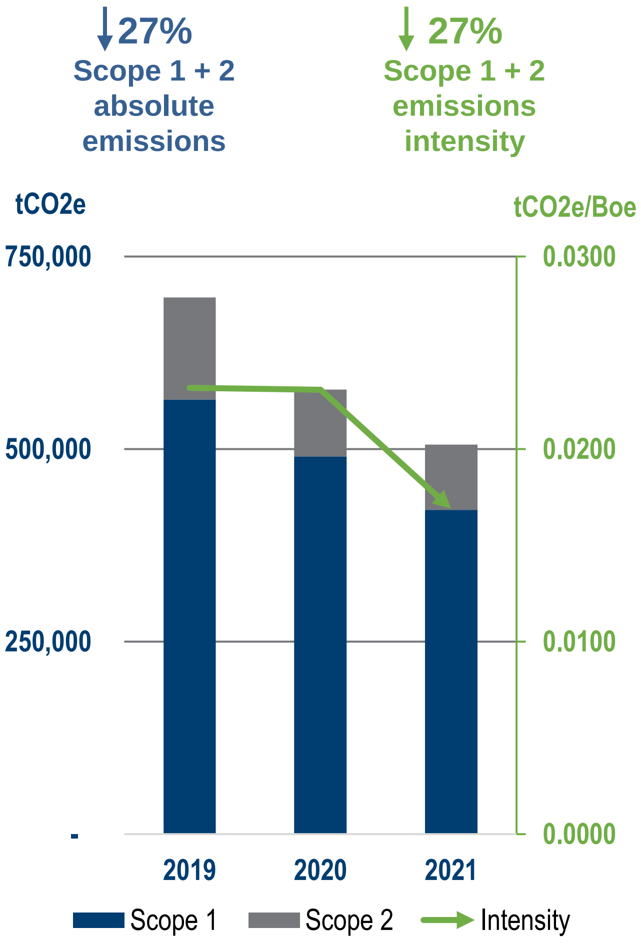
Play Data at 4,000m Avg. Lateral Length (3)	
IP 365 *(Boe/d)*	805
IP 365 CGR *(Bbl/MMcf)*	268
Sales Volume *(MBoe)*	1,321
Average CGR *(Bbl/MMcf)*	200
Sales Gas Volume *(Bcf)*	3.0
Sales Condensate *(MBbl)*	603
DCET *($MM)*	$12.0

- Implied capital efficiency of ~$14,900/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 are lower by approximately 7 percent and liquids sales volumes are 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)** See Advisories Appendix – Undeveloped Locations. **(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"
- Improved measurement combined with successful abatement initiatives resulted in significantly lower recorded fugitive emissions in 2021
- 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
- Recognized by Evaluate Energy in 2022 for the Company's emissions reductions initiatives

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
- Fully independent Audit, Compensation, Corporate Governance and Reserves Committees
- Environmental, Health and Safety Committee of the Board of Directors and senior management provide oversight in ESG related matters
- 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
- Anonymous Whistleblower Policy and portal

Strategic and Long-Term Investments

Paramount is unique in that it holds strategic positions in a number of public and private entities

Summary of Investments & Other Assets	
Investments in Public Companies (1)	~$380 million
Investments in Private Companies (2)	~$70 million
Drilling Rigs – Book Value (2)	~$60 million
Undeveloped Land	Not quantified
Total	**~$510 million**

Other Long-Term Resources

Clearwater 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

- Four triple-sized walking rigs
- Three conventional triple-sized rigs
- Constructing new super-spec walking rig for use in Paramount's 2023 drilling program

Cavalier Energy Inc.

Wholly owned by Paramount

- Cavalier Energy's lands are prospective for in-situ thermal oil recovery and heavy oil
- 1.360 million gross acres of land located primarily in the Athabasca and Peace River regions of Alberta
- ~430 gross sections with Clearwater and Bluesky potential
- 2 appraisal wells being drilled in 2023

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 ~135 net sections

Horn River Basin

Muskwa Shale Play

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

Mackenzie Delta

- ~181,912 (29,342 net) acres

Central Mackenzie

- 301,055 (177,544 net) acres

(1) Market value of public companies as at September 30, 2022 (includes ~37.3 million shares of NuVista Energy Ltd. @ $9.81/share). **(2)** Carrying value as at September 30, 2022. Investments in Private Companies includes the Company's investments in Sultran and Westbrick Energy Ltd. For further details refer to Paramount's consolidated interim financial statements as at and for the three months ended September 30, 2022.

Paramount Investment Attributes

Paramount offers a unique investment proposition

- 40+ 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 ~$3.9 billion (~$27 per basic share(1)) over the next five years
- Paramount does not forecast cash tax in its five-year outlook until 2026(2)
- Strong liquidity position with an undrawn $1.0 billion financial covenant based revolving credit facility (May 2026 maturity)
- Stakeholder-aligned management and board with significant insider ownership
- The Company implemented a regular monthly dividend of $0.02 per share in July 2021, which has now been increased over six-fold to $0.125 per share through four increases
- Special cash dividend of $1.00/share in January 2023 (3)

(1) Based on 142.8 million outstanding class A Common Shares as at January 11, 2023. **(2)** See the Advisories Appendix – Forward-Looking Information for a description of certain of the key underlying assumptions. **(3)** January 18, 2023 record date, January 25, 2023 payment date.

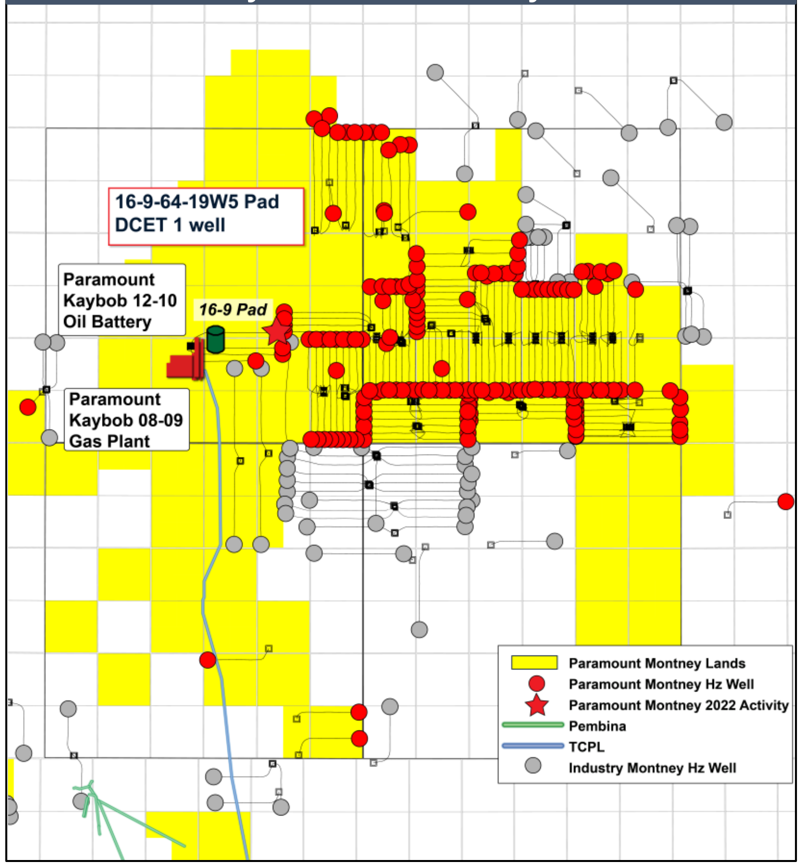
Appendix

Other Montney Assets at Kaybob

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

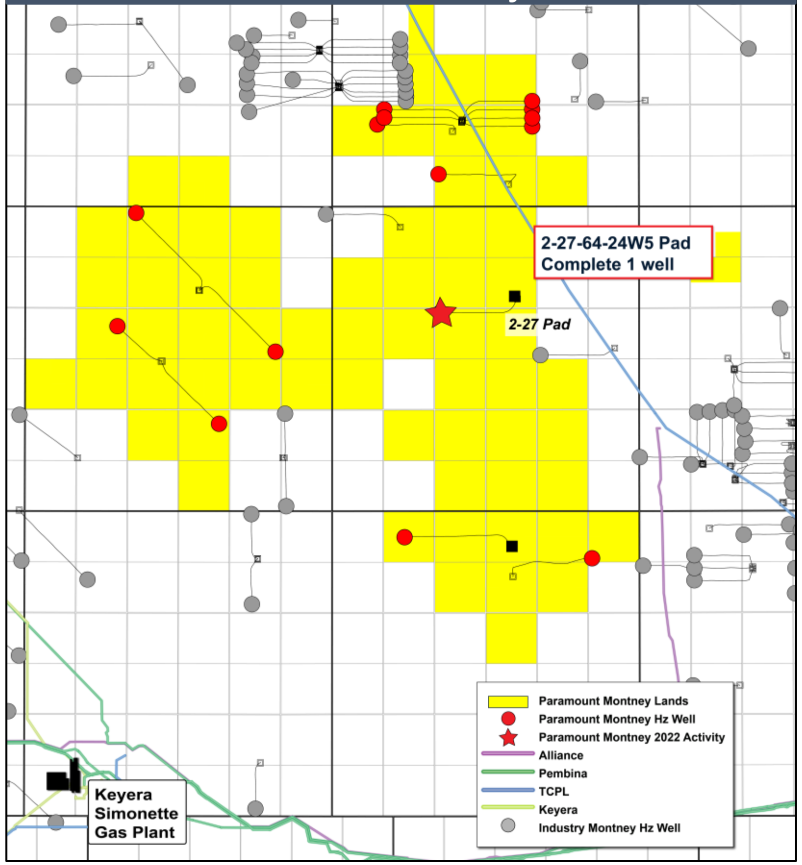
- 26 full field development locations (~54% assigned reserves as at December 31, 2021) [(1)]

Kaybob North Montney Oil



- 84 full field development locations (no locations assigned reserves as at December 31, 2021) [(1)]

Ante Creek Montney Oil

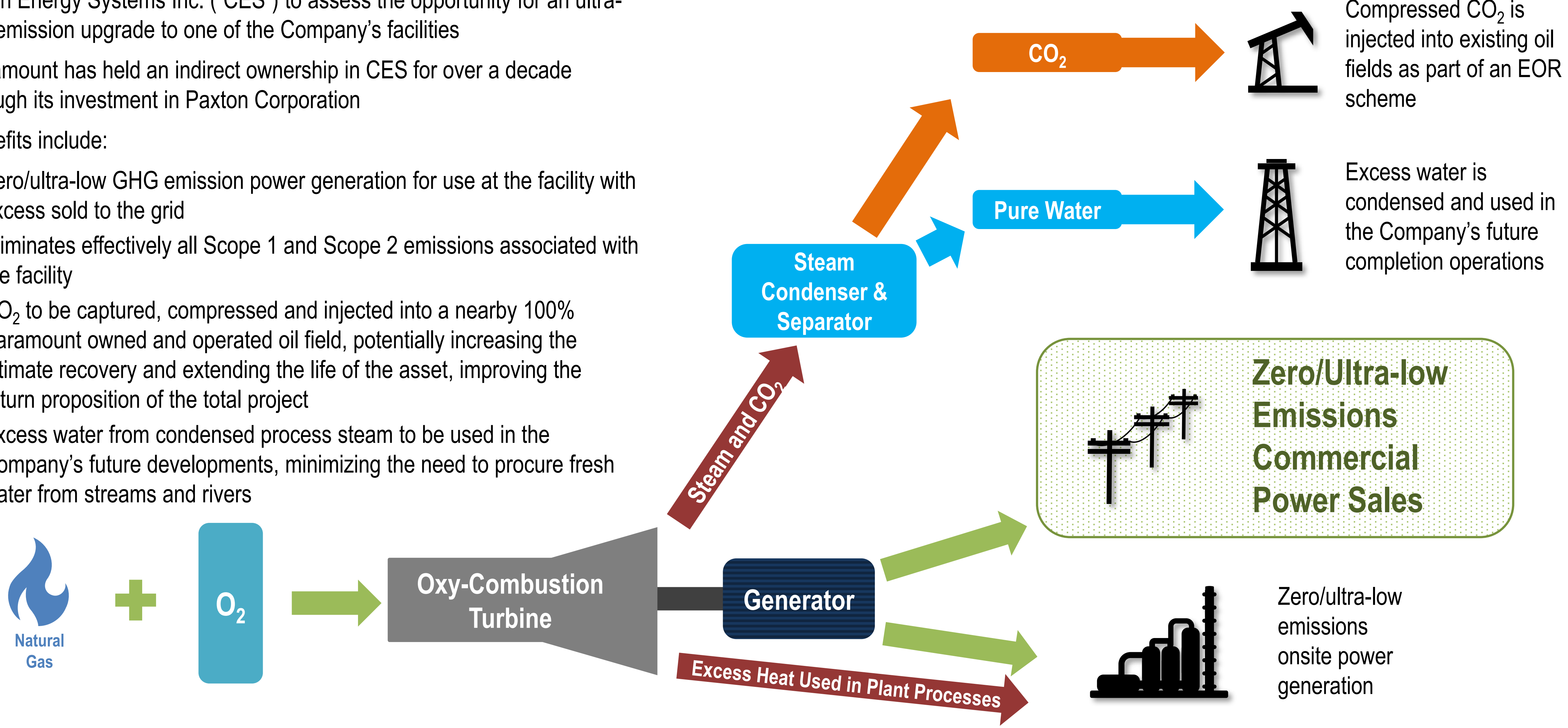


(1) See Advisories Appendix – Undeveloped Locations.

Potential Emission Reduction Initiative

Paramount continues to evaluate a zero/ultra-low emissions power generation, CCUS and EOR project

- Paramount has engaged an outside engineering firm and is working with Clean Energy Systems Inc. ("CES") to assess the opportunity for an ultra-low emission upgrade to one of the Company's facilities
- Paramount has held an indirect ownership in CES for over a decade through its investment in Paxton Corporation
- Benefits include:
  - Zero/ultra-low GHG emission power generation for use at the facility with excess sold to the grid
  - Eliminates effectively all Scope 1 and Scope 2 emissions associated with the facility
  - CO_2 to be captured, compressed and injected into a nearby 100% Paramount owned and operated oil field, potentially increasing the ultimate recovery and extending the life of the asset, improving the return proposition of the total project
  - Excess water from condensed process steam to be used in the Company's future developments, minimizing the need to procure fresh water from streams and rivers



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 (Bcf)	Cumulative [2] CGR [3] (Bbl/MMcf)	Days on Production
16-17 Pad (East & West Wells)										
02/09-15-066-05W6/0		981	557	2.5	219	138	76	373	205	201
03/16-15-066-05W6/0		831	473	2.2	220	123	65	344	190	193
04/16-15-066-05W6/0		1,768	826	5.7	146	295	134	961	140	195
05/16-15-066-05W6/0		1,508	677	5.0	136	251	112	836	134	202
00/13-18-066-05W6/0		1,812	919	5.4	171	280	127	915	139	197
02/12-18-066-05W6/0		1,147	566	3.5	162	187	90	582	155	200
02/13-18-066-05W6/0		2,372	1,552	4.9	315	356	175	1,086	161	197
Avg. per well	**$6.8**	**1,488**	**796**	**4.2**	**191**	**233**	**111**	**728**	**153**	**198**
2021 Wells										
19 wells (Avg. per well)	$6.3	1,872	988	5.3	186	543	250	1,760	142	449
2020 Wells										
15 wells (Avg. per well)	$7.8	1,548	907	3.8	236	558	276	1,693	163	723
2019 Wells										
8 wells (Avg. per well)	$12.3	1,825	1,262	3.4	373	630	383	1,481	259	1,045
2018 Wells										
5 wells (Avg. per well)	$11.9	1,760	1,051	4.3	247	787	412	2,251	183	1,146
2016/2017 Wells										
27 wells (Avg. per well)	$13.3	1,969	1,171	4.8	245	889	441	2,687	164	1,455

**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 are approximately 10 percent lower and NGLs sales volumes are approximately 6 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 25, 2022. Natural gas sales volumes are approximately 10 percent lower and NGLs sales volumes are approximately 6 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

		Peak 30-Day (1)				Cumulative (2)				
	DCET Costs *($MM)*	Total *(Boe/d)*	Wellhead NGLs *(Bbl/d)*	Wellhead Shale Gas *(MMcf/d)*	CGR (3) *(Bbl/MMcf)*	Total *(MBoe)*	Wellhead NGLs *(MBbl)*	Wellhead Shale Gas *(Bcf)*	CGR (3) *(Bbl/MMcf)*	Days on Production
6-32 Pad										
00/01-20-067-06W6/0		1,680	914	4.6	199	95	51	263	195	61
00/02-20-067-06W6/0		1,672	930	4.5	209	93	50	255	198	61
00/03-20-067-06W6/0		1,584	851	4.4	193	55	30	153	194	37
00/04-20-067-06W6/0		1,614	907	4.2	214	51	29	134	214	33
02/01-20-067-06W6/0		1,774	1,022	4.5	227	100	57	256	224	61
02/02-20-067-06W6/0		1,843	1,140	4.2	270	101	59	253	233	61
02/03-20-067-06W6/0		1,888	1,174	4.3	274	60	37	137	271	33
02/04-20-067-06W6/0		1,721	1,019	4.2	242	55	33	134	246	33
Avg. per well	**$7.5**	**1,722**	**995**	**4.4**	**228**	**76**	**43**	**198**	**218**	**48**
8-22 Pad										
00/01-24-067-06W6/0		1,408	685	4.3	158	142	60	491	123	111
00/08-24-067-06W6/0		1,354	536	4.9	109	171	63	649	97	139
02/01-24-067-06W6/0		1,582	795	4.7	168	146	75	425	176	105
02/08-24-067-06W6/0		1,318	581	4.4	131	155	63	550	115	131
W0/04-21-067-06W6/0		1,962	1,228	4.4	279	187	104	502	207	108
W0/05-21-067-06W6/0		1,559	926	3.8	244	172	87	506	172	138
W2/05-21-067-06W6/0		1,551	791	4.6	174	148	70	467	151	108
W2/12-21-067-06W6/0		1,457	741	4.3	172	174	77	578	134	138
Avg. per well	**$7.3**	**1,524**	**785**	**4.4**	**177**	**162**	**75**	**521**	**143**	**122**
9-22 Pad										
00/13-21-067-06W6/0		1,236	490	4.5	109	220	82	829	99	204
02/09-24-067-06W6/0		1,256	645	3.7	176	247	123	748	164	243
02/16-24-067-06W6/0		1,494	777	4.3	181	296	125	1,027	121	253
03/16-24-067-06W6/0		1,744	1,069	4.1	264	318	177	843	210	275
S0/04-28-067-06W6/0		1,434	802	3.8	211	269	142	762	187	250
W0/12-21-067-06W6/0		1,823	1,172	3.9	300	303	171	790	217	230
W0/13-21-067-06W6/0		1,657	930	4.4	213	293	149	868	171	229
Avg. per well	**$6.7**	**1,521**	**841**	**4.1**	**206**	**278**	**138**	**838**	**165**	**241**
6-4 Pad										
7 wells (Avg. per well)	$6.8	**1,292**	**794**	**3.0**	**266**	**279**	**161**	**707**	**228**	**387**
5-3 West Pad										
5 wells (Avg. per well)	$7.5	1,189	795	2.4	336	364	222	849	262	559
5-3 East Pad										
12 wells (Avg. per well)	$9.6	1,588	1,044	3.3	320	385	222	975	228	788
9-3 Pad										
11 wells (Avg. per well)	$11.3	1,051	722	2.0	366	420	248	1,035	240	1,045

**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 are approximately 11 percent lower and NGLs sales volumes are 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 25, 2022. Natural gas sales volumes are approximately 11 percent lower and NGLs sales volumes are 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.

Paramount resources ltd.

Advisories

Advisories

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) expected fourth quarter 2022 and 2022 annual average sales volumes; (ii) expected 2022 annual capital expenditures; (iii) planned capital expenditures in 2023 and the allocation thereof; (iv) forecast sales volumes in 2023 and certain periods therein; (v) forecast free cash flow in 2023; (vi) preliminary anticipated capital expenditures in 2024 and the allocation thereof and the resulting expected 2024 average sales volumes and free cash flow; (vii) planned or forecast abandonment and reclamation expenditures; (viii) the Company's free cash flow priorities, (ix) the potential payment of future dividends; (x) illustrative adjusted funds flow in 2023 and 2024; (xi) anticipated geological and geophysical expenses; (xii) illustrative year-over-year production, adjusted funds flow and free cash flow growth in 2023 and 2024; (xiii) planned production growth at Karr and Willesden Green Duvernay; (xiv) the Company's five-year outlook for capital expenditures, production growth and cumulative free cash flow; (xv) the statement that the Company does not forecast cash tax in its five-year outlook until 2026; (xvi) targeted potential plateau production rates and the years of production that may be supported by undeveloped locations at Karr, Wapiti, Kaybob North Duvernay and Willesden Green; (xvii) potential rates of return for the Company's properties; (xviii) undeveloped drilling locations at various properties; (xix) play data, anticipated well performance and forecast netback for various properties; (xx) planned exploration, development and production activities, including the expected timing of completing and bringing new wells on production and the expected timing of completion, cost and capacity of planned facilities and infrastructure; (xxi) preliminary and estimated DCET costs and completion costs; (xxii) the expectation that Kaybob North Duvernay will contribute to the next wedge of production growth; (xxiii) the expected realization of capital cost efficiencies at Kaybob North Duvernay and Willesden Green; (xxiv) expected production during certain periods at Willesden Green and the expectation that the capital program over the next five years at Willesden Green will grow production to approximately 30,000 Boe/d (58% liquids) by 2027; and (xxv) general business strategies and objectives.

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 likely impact of the COVID-19 pandemic and of the Russian invasion of the Ukraine; (iii) royalty rates, taxes and capital, operating, processing, transportation, 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 product 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 to current and new customers; (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; (xiii) the receipt of benefits under government programs; (xiv) the application of regulatory requirements respecting abandonment and reclamation; and (xv) 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).

In addition to the above: (a) forecast 2023 free cash flow is based on (i) the midpoint of forecast capital spending and production, (ii) $55 million in abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $63.00/Boe (US$80.00/Bbl WTI, US$5.00/MMBtu NYMEX, $4.74/GJ AECO), (v) a $US/$CAD exchange rate of $0.730, (vi) royalties of $10.30/Boe, (vii) operating costs of $11.40/Boe and (vii) transportation and processing costs of $3.65/Boe; and (b) estimated 2024 free cash flow is based on (i) the midpoint of estimated capital spending and production, (ii) $40 million in abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $58.45/Boe (US$75.00/Bbl WTI, US$4.50/MMBtu NYMEX, $4.27/GJ AECO), (v) a $US/$CAD exchange rate of $0.735, (vi) royalties of $9.85/Boe, (vii) operating costs of $10.45/Boe and (vii) transportation and processing costs of $3.50/Boe. With respect to the statement that Paramount does not forecast cash tax in its five-year outlook until 2026, 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, 2022; (ii) fluctuations in commodity prices; (iii) changes in capital spending plans and planned exploration and development activities; (iv) the potential for changes to expected fourth quarter 2022 and 2022 annual average sales volumes upon finalization; (v) the potential for changes to expected 2022 annual capital expenditures upon finalization; (vi) the potential for changes to preliminary anticipated 2024 capital expenditures prior to finalization and changes to the resulting expected or illustrative 2024 average sales volumes, free cash flow and adjusted funds flow, (vii) the potential for changes to the Company's five-year outlook for capital expenditures, production growth and cumulative free cash flow; (viii) changes in foreign currency exchange rates, interest rates and the rate of inflation, (ix) the uncertainty of estimates and projections relating to future production, revenue, free cash flow, reserves additions, product yields (including condensate to natural gas ratios), resources recoveries, well performance, royalty rates, taxes and costs and expenses; (x) the ability to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms; (xi) operational risks in exploring for, developing and producing natural gas and liquids, including the risks of spills, leaks or blowouts; (xii) 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; (xiii) potential disruptions or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities); (xiv) processing, pipeline and fractionation infrastructure outages, disruptions and constraints; (xv) risks and uncertainties involving the geology of oil and gas deposits; (xvi) the uncertainty of reserves estimates; (xvii) general business, economic and market conditions; (xviii) the ability to generate sufficient cash from operating activities to fund, or otherwise finance, planned exploration, development and operational activities and meet current and future commitments and obligations (including product processing, transportation, fractionation and similar commitments and obligations); (xix) changes in, or in the interpretation of, laws, regulations or policies (including environmental laws); (xx) the ability to obtain required governmental or regulatory approvals in a timely manner and to enter into and maintain leases and licenses; (xxi) the effects of weather and other factors, including wildlife and environmental restrictions which affect field operations and access; (xxii) uncertainties regarding the timing and costs of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination; (xxiii) uncertainties regarding Indigenous claims and in maintaining relationships with local populations and other stakeholders; (xxiv) the outcome of existing and potential lawsuits, insurance claims, regulatory actions, audits and assessments; and (xxv) other risks and uncertainties described elsewhere in this presentation and in Paramount's filings with Canadian securities authorities, including its Annual Information Form for the year ended December 31, 2021, which is available under the Company's profile on SEDAR at www.sedar.com.

Advisories

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 presentation, 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 presentation. Such assumptions are based on management's assessment of the relevant information currently available, and any financial outlook included in this presentation 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 January 11, 2023. The internally estimated play data information for Karr, Wapiti, Kaybob North Duvernay and Willesden Green contained at pages 8, 11, 14 and 15 in this presentation has been prepared effective November 1, 2022. In each case, events or information subsequent to the applicable effective dates have not been incorporated.

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			
	2022		2021		**2021**		2020	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**618.9**	***68.92***	369.2	*48.86*	**1,383.6**	***46.23***	626.7	*25.05*
Royalties	**(89.4)**	***(9.96)***	(30.9)	*(4.09)*	**(127.0)**	***(4.24)***	(31.3)	*(1.25)*
Operating expense	**(110.0)**	***(12.25)***	(83.3)	*(11.02)*	**(340.4)**	***(11.37)***	(297.1)	*(11.88)*
Transportation and NGLs processing	**(34.4)**	***(3.83)***	(30.3)	*(4.01)*	**(114.5)**	***(3.83)***	(101.3)	*(4.05)*
Sales of commodities purchased (1)	**77.9**	***8.67***	31.3	*4.14*	**75.5**	***2.52***	52.4	*2.10*
Commodities purchased (1)	**(76.4)**	***(8.51)***	(31.4)	*(4.16)*	**(76.1)**	***(2.54)***	(53.1)	*(2.12)*
	386.6	**43.04**	224.6	29.72	**801.1**	**26.77**	196.3	7.85

Karr netbacks for the applicable periods are summarized below:

	Three Months ended September 30				Year Ended			
	2022		2021		**2021**		2020	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**261.8**	***74.70***	195.3	*53.23*	**725.4**	***51.78***	234.6	*30.86*
Royalties	**(47.7)**	***(13.62)***	(17.1)	*(4.66)*	**(74.5)**	***(5.32)***	(9.7)	*(1.28)*
Operating expense	**(39.6)**	***(11.29)***	(33.1)	*(9.03)*	**(134.1)**	***(9.57)***	(107.2)	*(14.10)*
Transportation and NGLs processing	**(15.6)**	***(4.46)***	(15.7)	*(4.27)*	**(59.7)**	***(4.26)***	(35.4)	*(4.65)*
	158.9	***45.33***	129.4	*35.27*	**457.1**	***32.63***	82.3	*10.83*

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

	Three Months ended September 30				Year Ended			
	2022		2021		**2021**		2020	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**457.5**	***75.37***	275.8	*54.92*	**1,006.1**	***53.14***	356.2	*31.32*
Royalties	**(70.5)**	***(11.62)***	(20.5)	*(4.08)*	**(87.2)**	***(4.61)***	(14.3)	*(1.26)*
Operating expense	**(68.1)**	***(11.22)***	(52.6)	*(10.47)*	**(205.3)**	***(10.84)***	(162.4)	*(14.28)*
Transportation and NGLs processing	**(25.7)**	***(4.24)***	(22.5)	*(4.48)*	**(82.9)**	***(4.37)***	(53.1)	*(4.66)*
	293.2	***48.29***	180.2	*35.89*	**630.7**	***33.32***	126.4	*11.12*

Wapiti netbacks for the applicable periods are summarized below:

	Three Months ended September 30				Year Ended			
	2022		2021		**2021**		2020	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**195.7**	***76.27***	80.4	*59.62*	**280.7**	***57.02***	121.6	*32.25*
Royalties	**(22.8)**	***(8.88)***	(3.4)	*(2.49)*	**(12.7)**	***(2.58)***	(4.6)	*(1.21)*
Operating expense	**(28.5)**	***(11.12)***	(19.2)	*(14.25)*	**(71.2)**	***(14.46)***	(55.2)	*(14.64)*
Transportation and NGLs processing	**(10.1)**	***(3.94)***	(6.9)	*(5.09)*	**(23.2)**	***(4.72)***	(17.7)	*(4.70)*
	134.3	***52.33***	50.9	*37.79*	**173.6**	***35.26***	44.1	*11.70*

(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 corporate expenditures plus the change from the prior year in estimated future development capital included in the reserves evaluation prepared by McDaniel. F&D capital is used by management and investors, in calculating F&D costs, to represent the amount of capital invested in oil and gas exploration and development projects to generate reserves additions.

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

($ millions)	Grande Prairie Region (1)	
Proved Developed Producing	**2021**	2020
Capital expenditures	**229**	197
Corporate expenditures	**–**	–
Change in estimated future development capital	**(22)**	(4)
F&D Capital	**207**	193
Total Proved	**2021**	2020
Capital expenditures	**229**	197
Corporate expenditures	**–**	–
Change in estimated future development capital	**(182)**	(736)
F&D Capital	**47**	(539)
Proved Plus Probable	**2021**	2020
Capital expenditures	**229**	197
Corporate expenditures	**–**	–
Change in estimated future development capital	**(197)**	(1,106)
F&D Capital	**31**	(909)

(1) Columns may not add due to rounding.

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 by (ii) the net changes to reserves in such reserves category from the prior year from extensions/improved recovery, technical revisions and economic factors. F&D costs are a measure commonly used by management and investors to assess the relationship between capital invested in oil and gas exploration and development projects and reserve additions. Readers should refer to the information under the heading "Reserves and Other Oil and Gas Information – Reserves Reconciliation" in the Company's annual information form for the year ended December 31, 2021, which is available on www.sedar.com or at www.paramountres.com, for a description of the net changes to reserves in each reserves category from the prior year. See "Advisories – Oil and Gas Definitions and Measures" for more information about this measure.

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

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

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

Advisories

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, 2022 plus the forecast total proved plus probable netback over the remaining life of each well as calculated by management consistent with the forecasts, assumptions and methodology in the McDaniel Report but utilizing an updated price forecast that is the average of the October 1, 2022 price forecasts for McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Ltd. 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, 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 15 – Capital Structure in the unaudited Interim Condensed Consolidated Financial Statements of Paramount as at and for the three and nine months ended September 30, 2022 for: (i) a description of the composition and use of these measures, (ii) reconciliations of adjusted funds flow and free cash flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements, for the three and nine months ended September 30, 2022 and 2021 and (iii) a calculation of net debt and net debt to adjusted funds flow as at September 30, 2022 and December 31, 2021.

Supplementary Financial Measures

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

Oil and Gas Measures and Definitions

Natural Gas	
GJ	Gigajoules
GJ/d	Gigajoules 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

Liquids	
Bbl	Barrels
Bbl/d	Barrels per day
MBbl	Thousands of barrels
NGLs	Natural Gas Liquids
Condensate	Pentane and heavier hydrocarbons
WTI	West Texas Intermediate

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

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, 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 references to "CGR", "F&D costs" and "recycle ratio", metrics commonly used in the oil and natural gas industry. "CGR" means condensate to gas ratio and, except otherwise noted, is calculated by dividing sales condensate volumes by sales natural gas volumes. See "Advisories – Specified Financial Measures" for a description of the calculation and use of F&D costs and recycle ratio. "CGR", "F&D costs" and "recycle ratio" 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 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 a reliable indicator 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.

All information in this presentation respecting acres of land held, other than the Company's Duvernay rights at Willesden Green, is effective as of December 31, 2021 unless otherwise stated. The Company's Duvernay acres held at Willesden Green are as at September 30, 2022.

Additional information respecting the Company's oil and gas properties and operations is provided in the Company's annual information form for the year ended December 31, 2021 which is available on SEDAR at www.sedar.com.

Advisories

Product Type Information

This presentation includes references to forecast sales volumes of "liquids". "Liquids" refers to light and medium crude oil, tight 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.

Wapiti sales volumes in September 2022 of 30,589 Boe/d (54% liquids) were comprised of 84.9 MMcf/d of shale gas, 14,886 Bbl/d of condensate and 1,554 Bbl/d of other NGLs

Fourth quarter 2022 sales volumes are expected to have averaged approximately 97,500 Boe/d (55% shale gas and conventional natural gas combined, 39% light and medium crude oil, tight oil and condensate combined and 6% other NGLs) based on preliminary field estimates. Annual 2022 sales volumes are expected to have averaged 89,000 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).

The Company forecasts that 2023 annual sales volumes will average between 100,000 Boe/d and 105,000 Boe/d (55% shale gas and conventional natural gas combined, 39% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). First half 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, 39% 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 (54% shale gas and conventional natural gas combined, 40% light and medium crude oil, tight oil and condensate combined and 6% other NGLs).

The Company's preliminary 2024 guidance forecasts annual sales volumes that will average between 110,000 Boe/d and 120,000 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).

See "Product Type Information" at page 47 of the Company's Management's Discussion and Analysis for the three and nine months ended September 30, 2022 for a description of historical average sales volumes by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium 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 1, 2022 and effective December 31, 2021 (the "McDaniel Report"). The price forecast used in the McDaniel Report is an average of the January 1, 2022 price forecasts for McDaniel and GLJ Petroleum Consultants Ltd. and the December 31, 2021 price forecast of Sproule Associates Ltd. The estimates of reserves contained in the McDaniel Report and referenced in this document are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates contained in the McDaniel Report and referenced in this document. There is no assurance that the forecast prices and costs assumptions used in the McDaniel Report will be attained, and variances could be material. Estimated future net revenue does not represent fair market value. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Readers should refer to the Company's annual information form for the year ended December 31, 2021, which is available on SEDAR at www.sedar.com, for a complete description of the McDaniel Report (including reserves by 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.

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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, 11, 14 and 15 in this presentation has been prepared effective November 1, 2022 by internal qualified reserves evaluators from Paramount in accordance with COGEH and using commodity prices of US$80.00/Bbl WTI, $5.00/MMBTU AECO and an exchange rate of US$0.730 for one Canadian dollar for 2023 and US$75.00/Bbl WTI, $4.50/MMBTU AECO and an exchange rate of US$0.735 for one Canadian dollar for 2024 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, except otherwise noted, 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 current 2023 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, 2021, which is available on SEDAR at www.sedar.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 December 31, 2021 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 presentation references the percentage of future potential undeveloped locations assigned reserves in the McDaniel Report solely to provide the reader with additional information concerning the proportion of 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. 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, for the referenced gross undeveloped locations of each applicable property, the number of locations that were assigned reserves in the McDaniel Report.

	Karr (Middle Montney)	Wapiti	Kaybob North Duvernay	Kaybob North Montney Oil	Ante Creek Montney Oil	Willesden Green Duvernay
Referenced Undeveloped Locations	244	229	148	26	84	705
Locations Assigned Reserves in the McDaniel Report	145	154	35	14	0	40

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