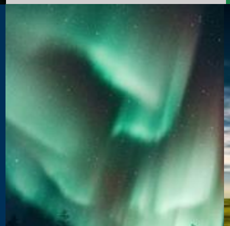


TSX: KEC

KIWETINOHK ENERGY

December 2024

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Territorial land acknowledgement

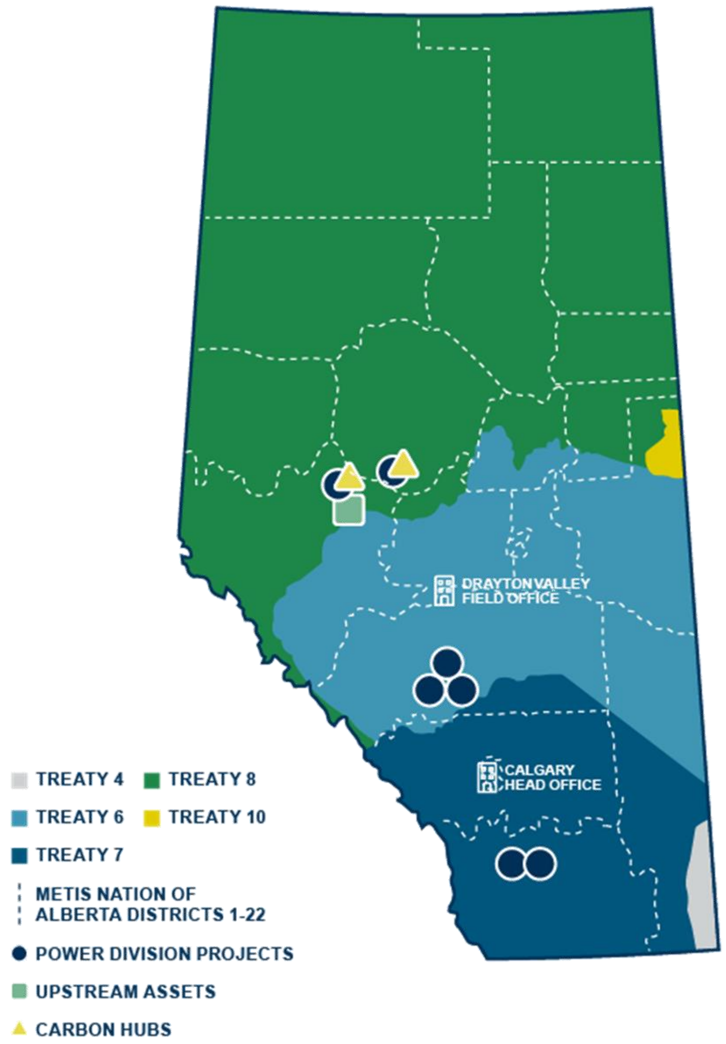
Kiwetinohk

means “north” or “northward” in Cree, the most widely spoken Indigenous language in Canada

We acknowledge the many diverse First Nations and Métis people whose ancestors have walked the land since time immemorial.

We are committed to do our part to advance reconciliation and ensure these lands are always a welcoming, healthy and prosperous place for all people who come from around the world and call them home.

Together we can build great communities for today and future generations.



Where we operate

UPSTREAM

Upstream production of
~26.8 Mboe/d

from prolific **Duvernay** and **Montney** plays expected in 2024 [1]

Increased production by
~148%⇧

since acquiring upstream assets (2Q21) expected to be achieved in 2024 [2]

Growth capacity to
40 Mboe/d

with Alliance pipeline capacity and infrastructure in place

POWER

~2 GW
of capacity in pipeline

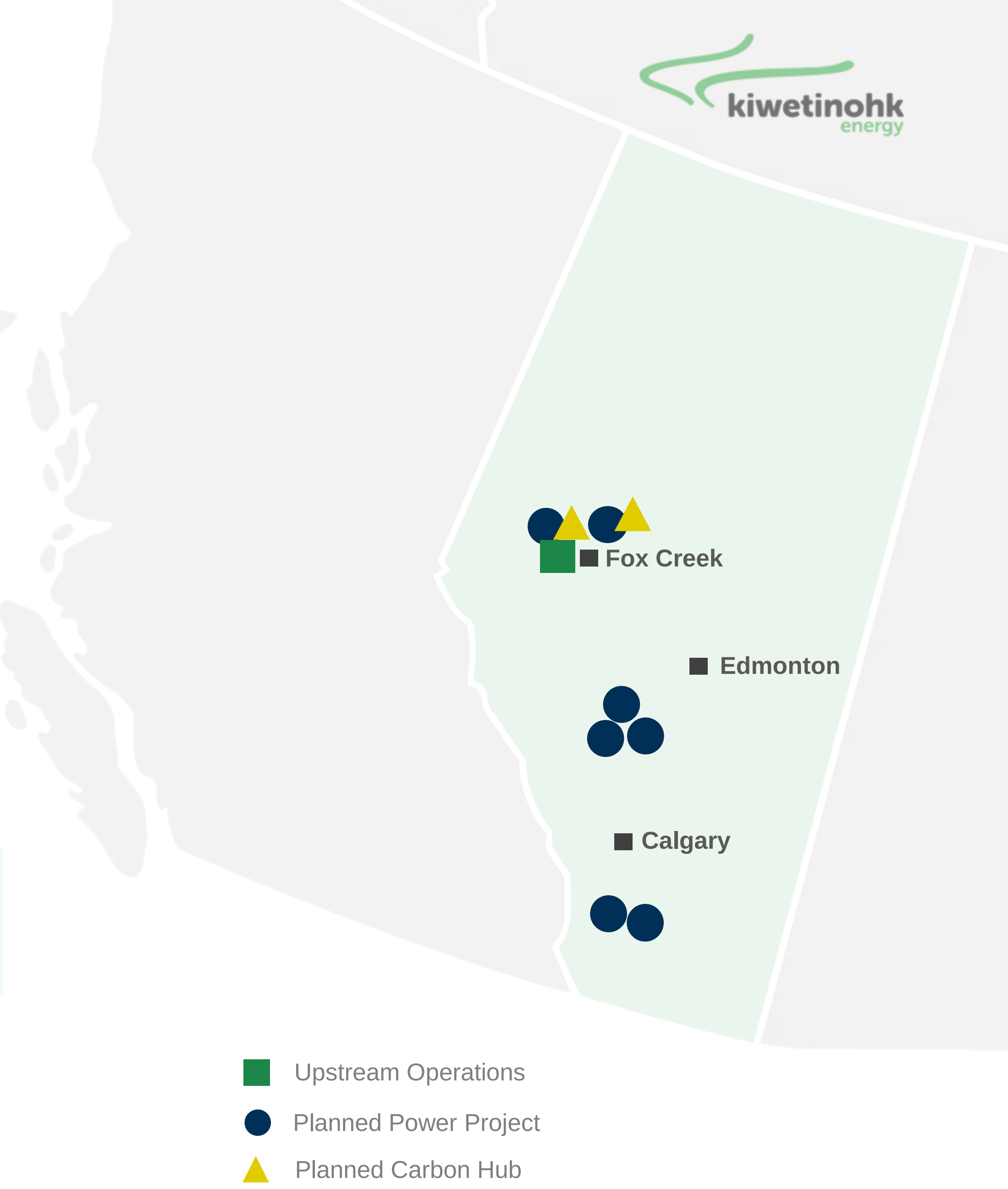
~40% solar capacity and **~60% gas fired** capacity

Baseload reinforcement
required in AB market

Significantly advanced portfolio in AESO queue

2 early-stage carbon hubs

awarded by Alberta government in proximity to operating areas



1. Based on mid-point of 2024 annual guidance.
2. Based on mid-point of 2024 annual guidance and growth is calculated from Q2 2021 average production of 10,797 boe/d.

Why invest in Kiwetinohk?

kiwetinohk energy

Robust upstream growth and top performing Duvernay wells

On track for three consecutive years of double-digit upstream production growth

Long inventory in prolific Duvernay and Montney plays

Executing the most productive wells in Duvernay

Infrastructure and egress advantage

Owned facility use driving down per unit operating costs

Supports peer leading netbacks

Critical egress capacity to US gas markets via Alliance Pipeline

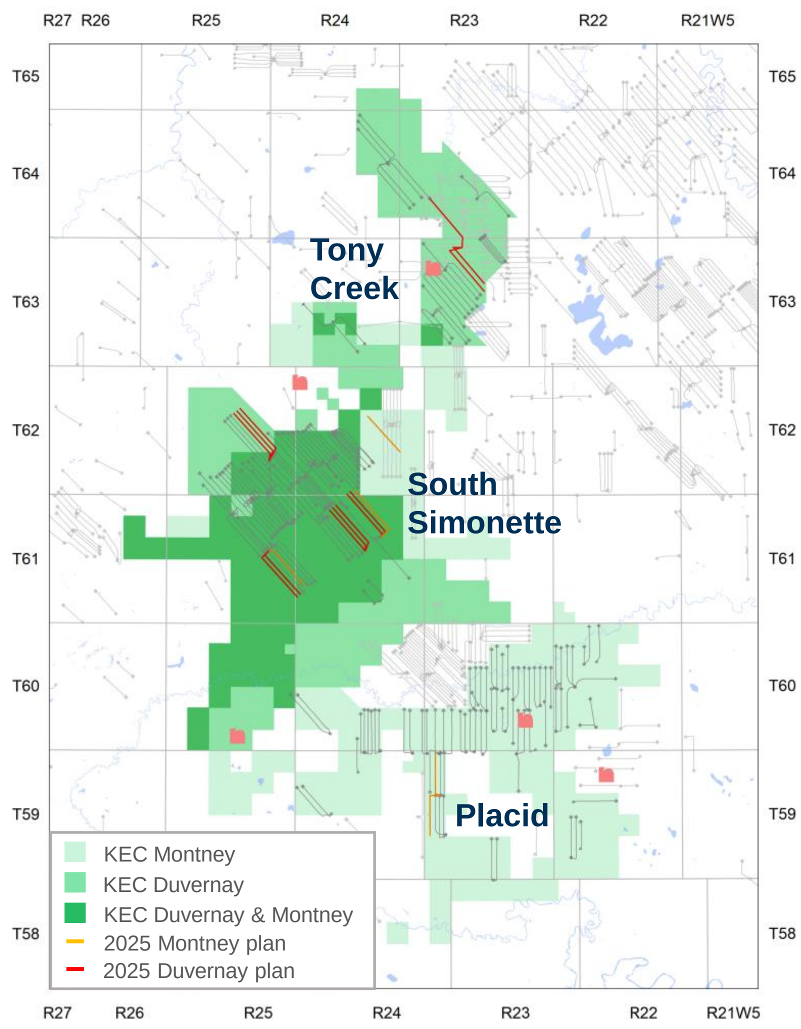
Leadership with proven track record

Pat Carlson, CEO, successfully built four previous energy companies

ARC Financial: KEC's largest shareholder and Canada's leading private equity energy investor

2025 budget focuses on high value growth

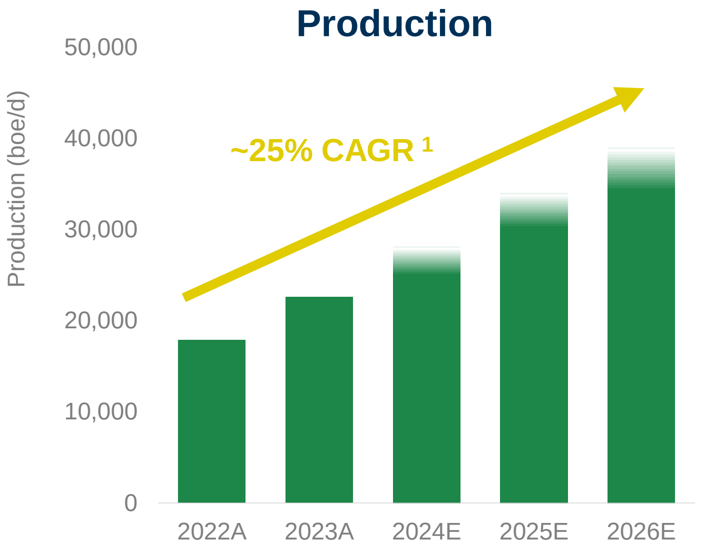
Fox Creek area map

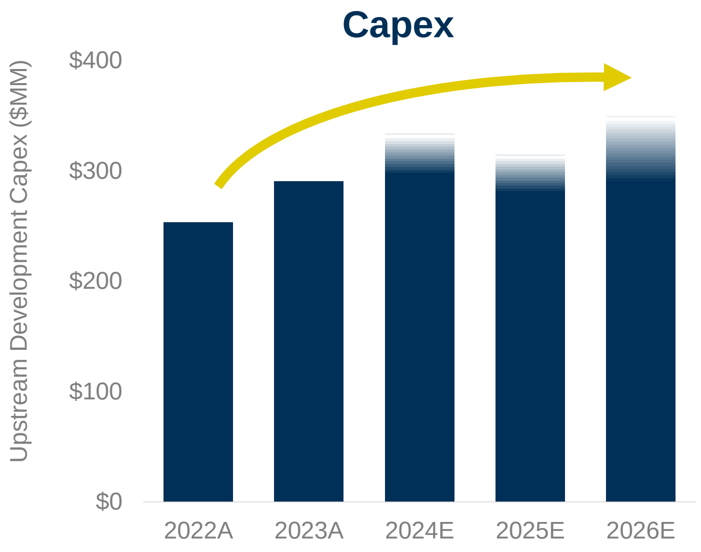


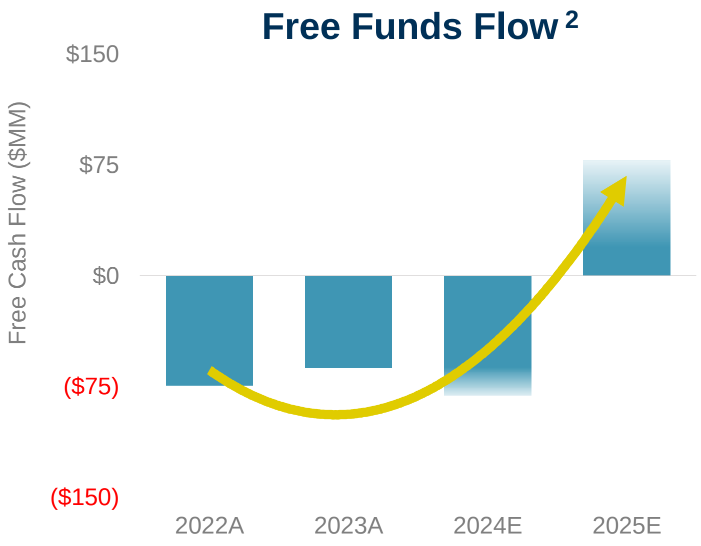
		IP180 [1]	% Liquids [1]	IRR [1, 2]
Tony Creek (Duvernay)	▪ Liquids-rich inventory with robust infrastructure ▪ 3 Duvernay wells in 2025	~1,000 boe/d	~70%	~50%
South Simonette (Duvernay)	▪ Repeatable top performing industry wells with high deliverability and returns ▪ Synergies through stacked Montney and Duvernay co-development ▪ Montney delineation well underway ▪ ~10 Duvernay and 3 Montney wells in 2025	~1,800 boe/d	~50%	~90%+
Placid (Montney)	▪ Low decline base production with dedicated infrastructure with spare capacity ▪ 2 Montney wells in 2025	~900 boe/d	~55%	~70%

1. Expected average performance from 2025 budget wells.
2. IRR ranges are before tax and estimated at US$70 WTI and US$3.50 HH.

Multi-year performance & outlook







Double digit production growth through 2026

Production growth target of ~40 Mboe/d

Majority of capital dedicated to DCET

~$200 – $220 MM upstream capital to sustain 2025 mid-point production

Inflection point on free funds flow

Free funds flow potential to grow with production

1. 2022A through 2026E.
2. Price assumptions: US$70/bbl WTI & US$3.50/MMBtu HH Free funds flow for 2026 has not been provided given uncertainty in predicting commodity prices.

2025 guidance summary [1]

As of December 16, 2024

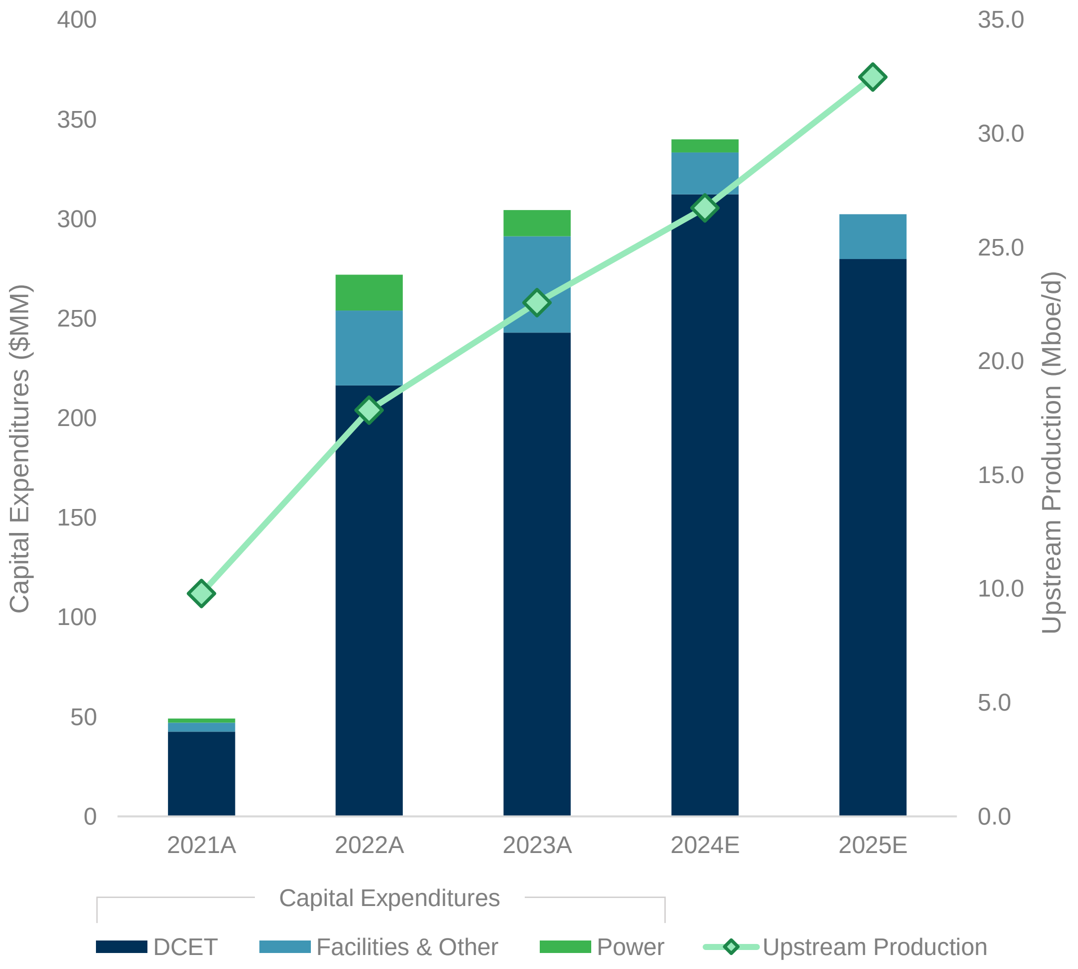
OPERATIONAL & FINANCIAL DETAILS

Average Sales Volumes	(Mboe/d)	31.0 – 34.0
Oil & Liquids %	(%)	45% – 49%
Royalty Rate (Crown)	(%)	6% – 8%
Operating Expense	($/boe)	$7.25 – $7.75
Transportation Expense	($/boe)	$6.00 – $6.25
Corporate G&A Expense [2]	($/boe)	$1.95 – $2.15
Upstream Capital guidance	($MM)	$290 – $315
DCET	($MM)	$270 – $290
Plant expansion, production maintenance and other	($MM)	$20 – $25

2024 SENSITIVITIES [1]

Adjusted Funds Flow from Operations		
US$60/bbl WTI & US$3.00/MMBTU HH & $0.72 USD/CAD	($MM)	$300 – $335
US$70/bbl WTI & US$3.50/MMBTU HH & $0.72 USD/CAD	($MM)	$360 – $400
Net Debt to Adjusted Funds Flow from Operations		
US$60/bbl WTI & US$3.00/MMBTU HH & $0.72 USD/CAD	(X)	0.8x – 1.0x
US$70/bbl WTI & US$3.50/MMBTU HH & $0.72 USD/CAD	(X)	0.5x – 0.6x

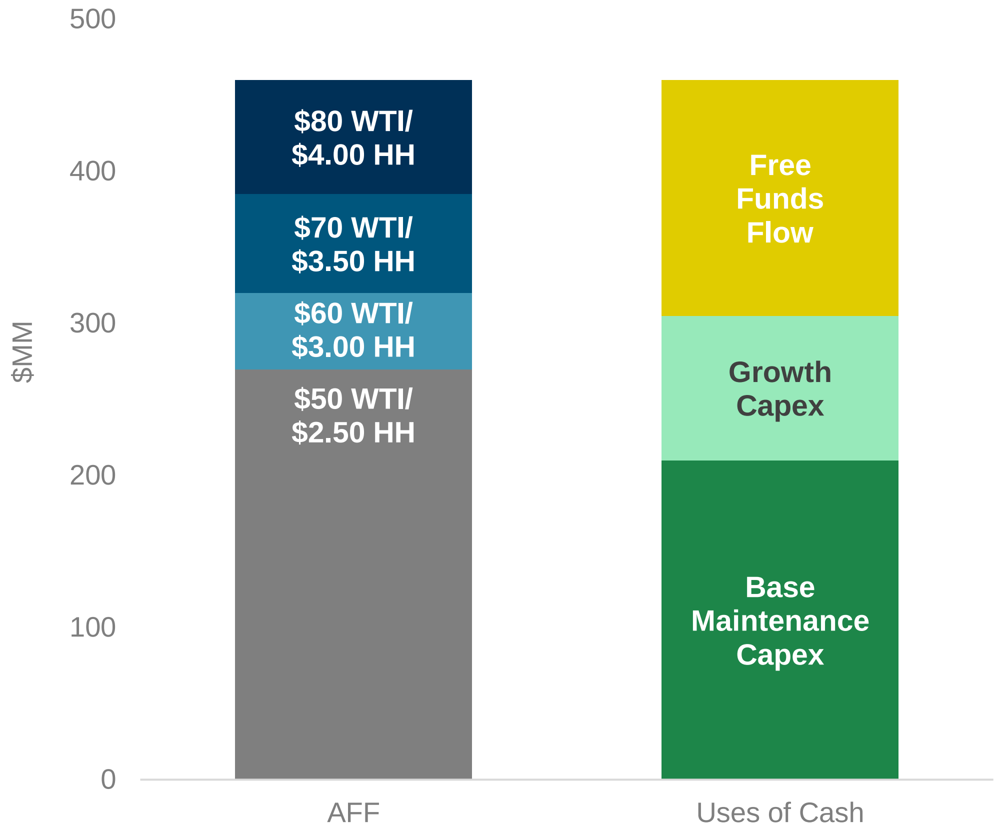
2025 capex focuses on high value investment [3]



1. See *"Non-GAAP and other financial measures"*.
2. Includes G&A expenses for all divisions of the Company – corporate, upstream, power and business development.
3. 2024 and 2025 figures based on midpoint of guidance.

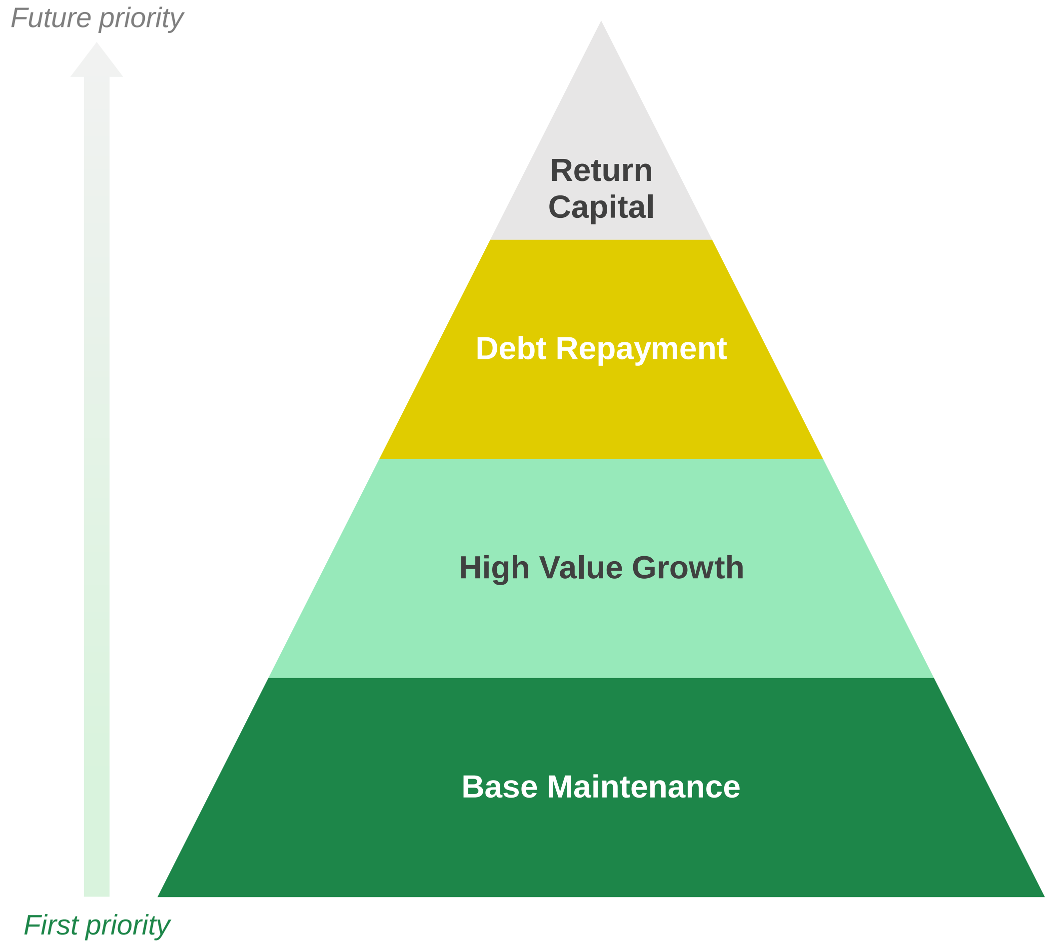
Funds flow sensitivities and allocation strategy

2025E adjusted funds flow allocation [1]



2025 capital budget funded at <$60 WTI / $3.00 HH

Capital allocation priorities (2025 – 2026)



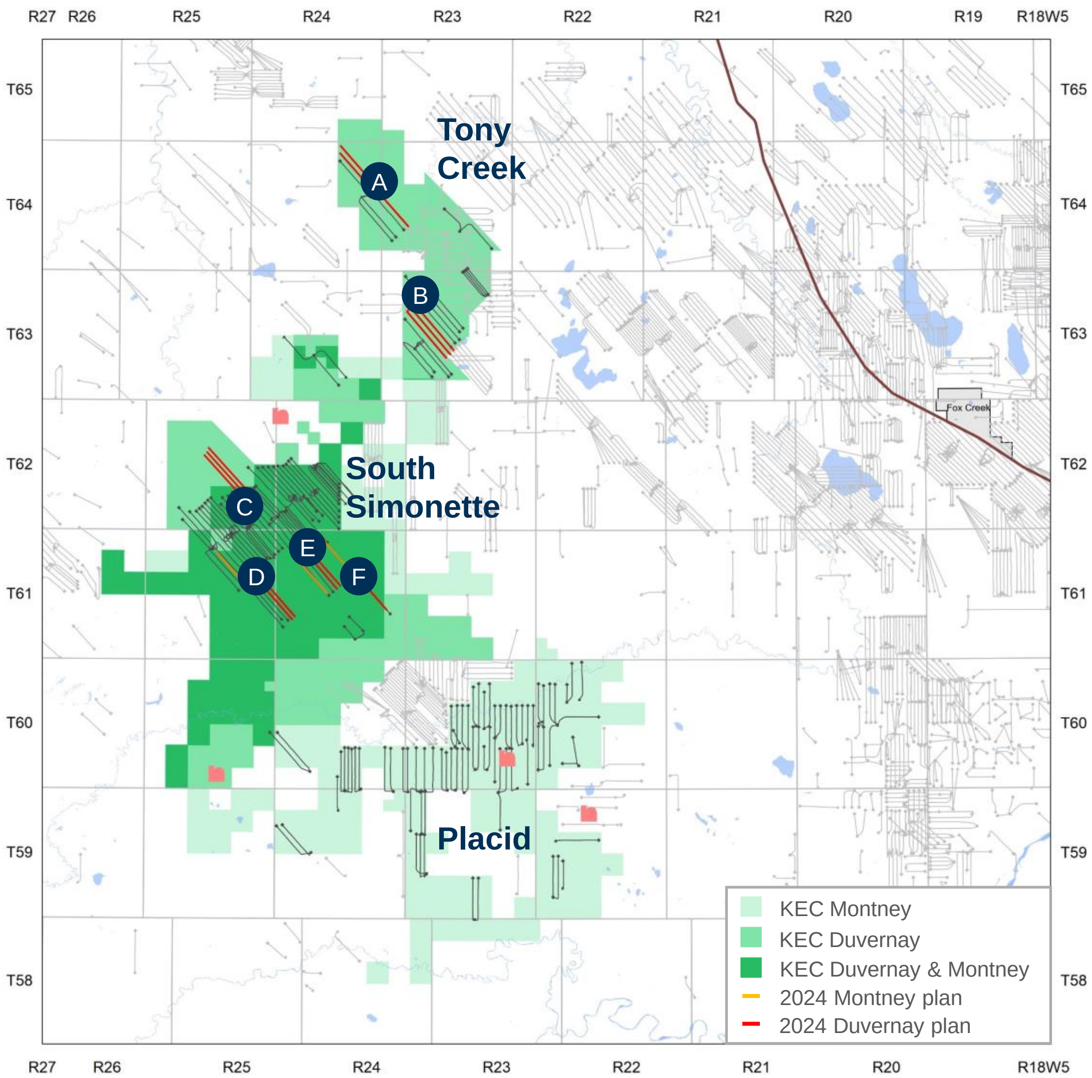
1. See "*Non-GAAP and other financial measures*".

Current activity and new well results [1]

Ⓐ 11-24 pad (black oil window)	
New wells	3 DUV
On-stream	Jul 2024
Avg peak 30-day rate per well	~950 boe/d
Oil & Condensate %	79%

Ⓑ 10-29 pad (volatile oil window)	
New wells	3 DUV
On-stream	Aug 2024
Avg peak 30-day rate per well	~1,680 boe/d
Oil & Condensate %	65%

Ⓒ 9-11 pad (very rich gas)	
New wells	3 DUV
On-stream	Q1 2025



Ⓓ 8-23 pad (very rich gas)	
Wells	3 DUV
On-stream	Feb 2024
Avg peak 30-day rate per well	~2,630 boe/d
Oil & Condensate %	40%
New wells	2 DUV + 1 MTNY
On-stream	November 2024

Ⓔ 14-29 pad (very rich gas)	
New wells	2 DUV + 1 MTNY
On-stream	Q1 2025

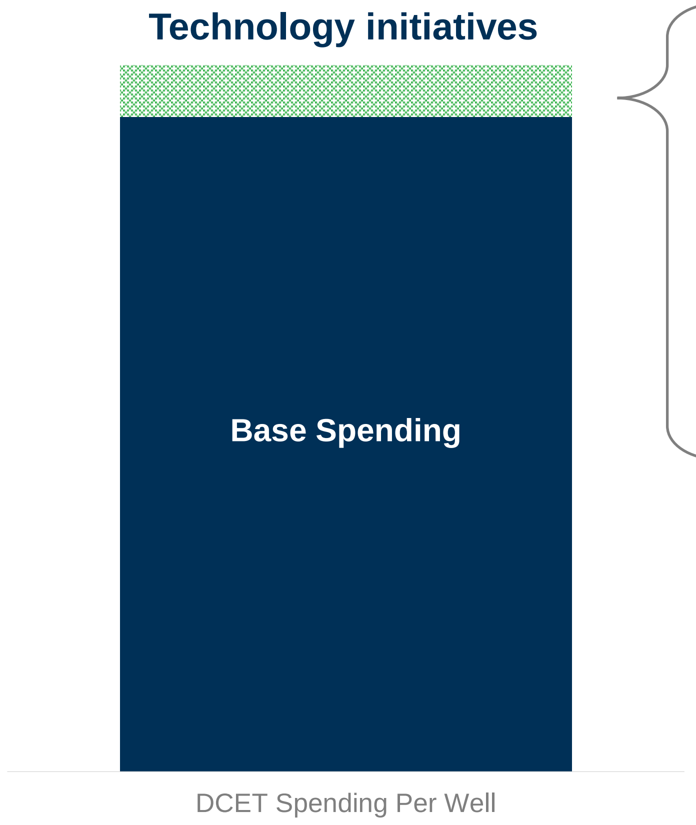
Ⓕ 1-27 pad (rich gas)	
New well	1 DUV
On-stream	Sep 2024
Avg peak 30-day rate	~2,420 boe/d
Oil & Condensate %	19%
New well	1 MTNY
On-stream	Sep 2024
Avg Peak 30-day rate	~1,850 boe/d
Oil & Condensate %	30%

1. See *"Reserves and oil & gas disclosure"*, and *"Forward-looking statements"*.

Continued investment in improving per-well economics

Key objectives

Extend lateral lengths	Optimizing frac scope for higher productivity	Improve well economics



Budgeted
~5% of DCET
per well in 2025

Incremental increase in capital to realize
improved well recoveries

Aligns with KEC's track record for achieving
best Duvernay wells

Successful implementation will be applied to future drilling locations to compound value

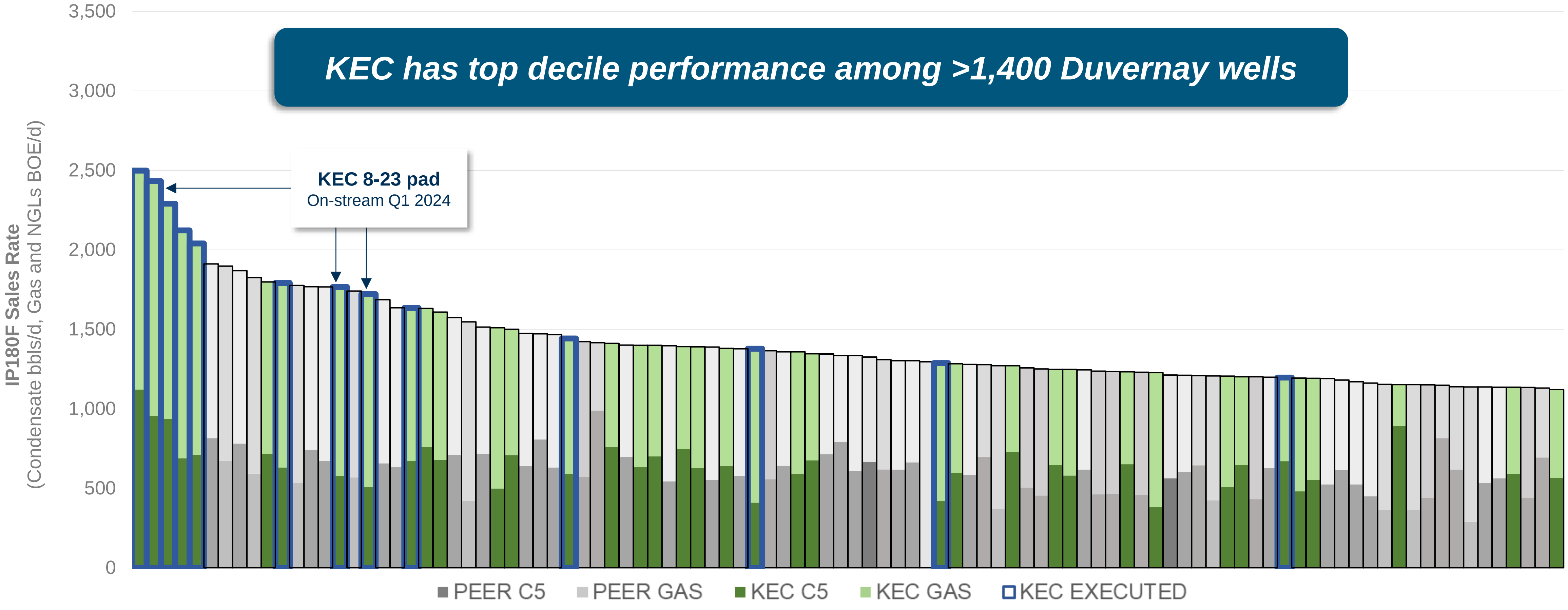
KEC consistently executing top Duvernay wells in Western Canada [1]

KEC has **6 of the top 10** and **39 of the top 100** producing Duvernay wells

Strong performance from combination of **leading methods** and **leading assets**

All top 100 wells located in **Kaybob**

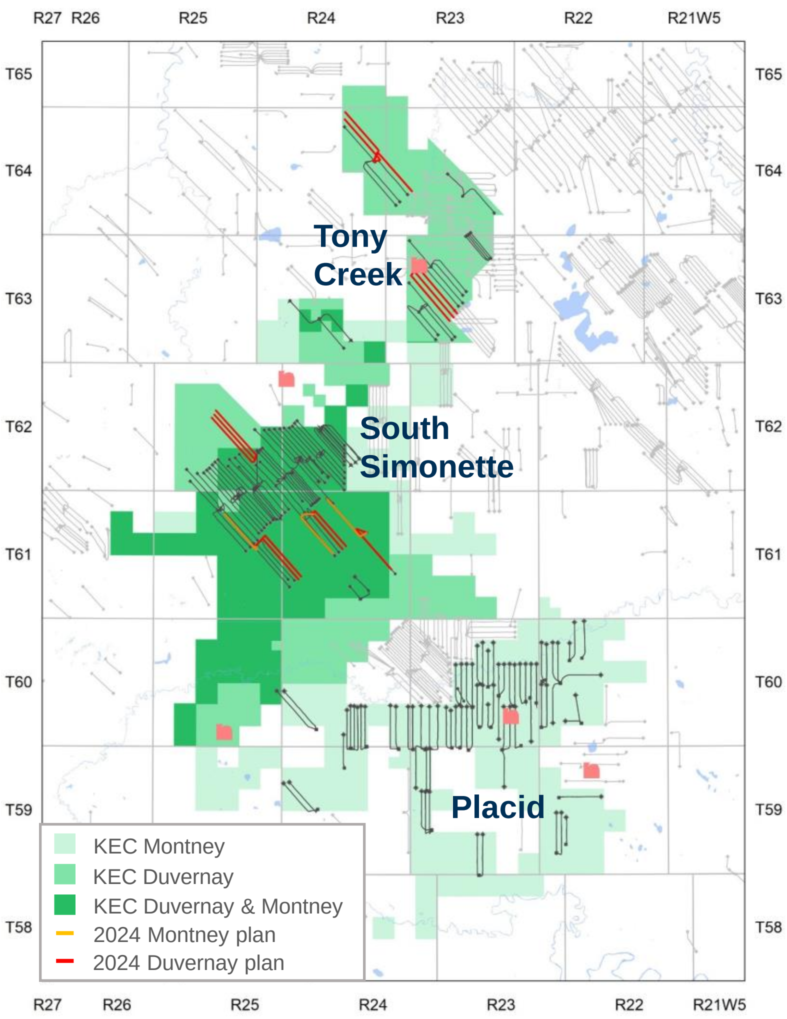
5 operators drilled **97% of the top 100** wells



1. Includes all Duvernay wells on-stream as of June 2024. Forecast data provided by Turing Analytics, Inc. Volumes from Petrinex data, using sales gas volumes, C2-C4 volumes and a combination of sales condensate, oil and C5.

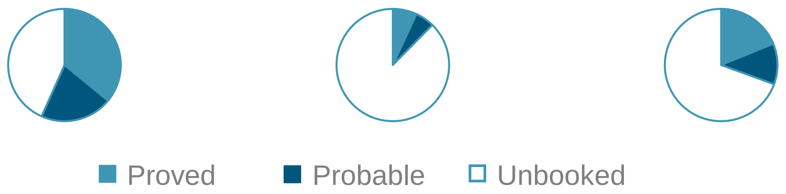
Extensive running room in Duvernay and Montney [1]

Fox Creek area map (2024 program)



YE2023	Duvernay	Montney	Total Company
Inventory	203	291	494

Breakdown

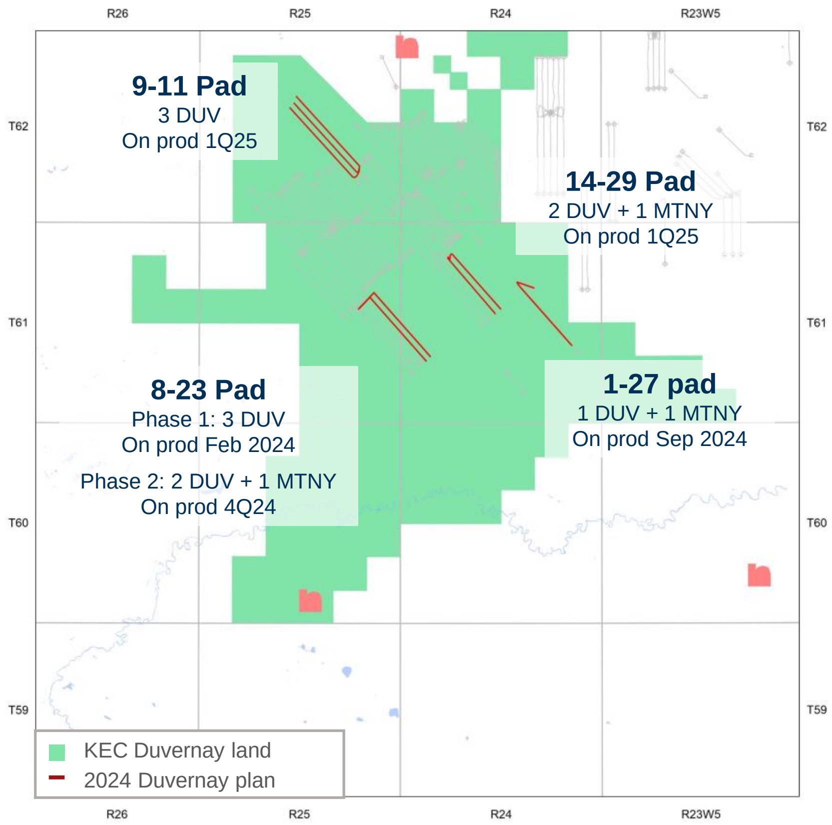


Inventory rich	Drilling to fill	High value production
494 future Duvernay and Montney locations	Owned and operated infrastructure through continuous rig program	Diverse commodity mix providing portfolio optionality
Booked inventory generates 2023 YE 2P **RLI of ~25 years**	Plan to drill, complete, equip and tie-in **17 wells in 2024**	~1/2 of production is oil, condensate and NGLs Inventory spans from <100 to >1,000 bbls/MMcf

1. See *"Reserves and oil & gas disclosure"*, and *"Forward-looking statements"*.

Attractive payouts on core Duvernay wells [1]

South Simonette Duvernay map



Drilling profitable Duvernay wells and demonstrating full economic potential of region

Development primarily focused on South Simonette operating area

144

total South Simonette Duvernay locations

74

of which identified in highly economic **rich gas window** (~50-200 bbl/MMcf)

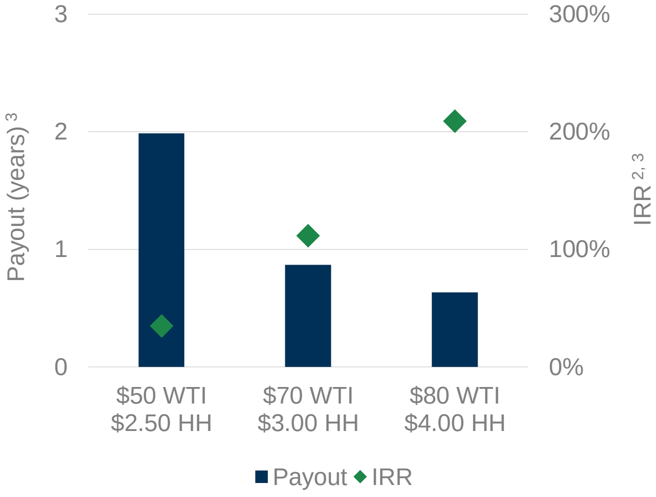
Exposure to favourable **Chicago gas market** with

120 MMcf/d

capacity on Alliance Pipeline

RICH GAS TYPE CURVE [2] 3,200M avg lateral length		
IP 365	(boe/d)	1,250
IP 365 CGR	(bbl/MMcf)	92
Sales Volume	(Mboe)	1,463
Average CGR	(bbl/MMcf)	79
Sales Gas Volume	(bcf)	4.9
Sales Condensate	(Mbbl)	380
DCET	($MM)	~$16

Implied capital efficiency of ~$12,800/boe/d



1. See "*Reserves and oil & gas disclosure*" and "*Non-GAAP and other financial measures*".
2. Weighted average type curve based on McDaniel and Associates 2023-year end reserves evaluation. Implied capital efficiency is calculated by dividing the DCET costs by the IP365 boe/d.
3. FX assumption for price decks shown is 0.75 CAD/USD. WTI price shown in US$/bbl and HH prices shown in US$/MMBtu.

Simonette and Placid Montney provide growth optionality

Plan to delineate, retain and prove extensive Montney inventory

~291
future locations[1] with only 12% booked

Overlapping land
with Simonette Duvernay lowers development cost

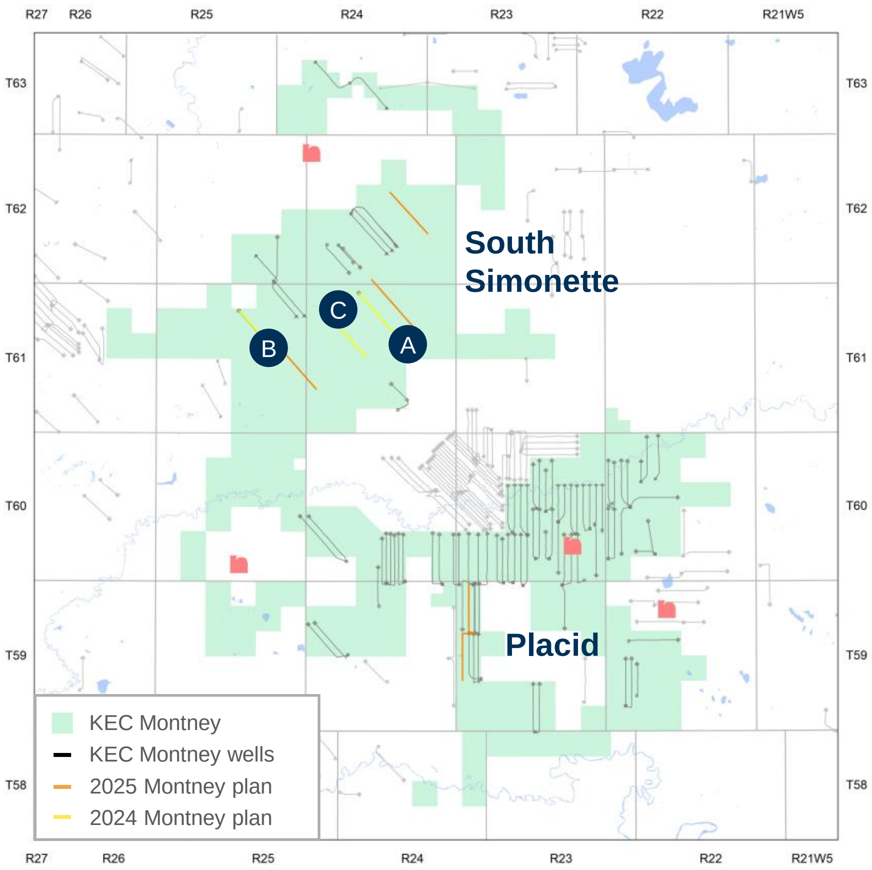
Lower relative D&C costs of
$10-12 MM/well
generate similar returns to Duvernay

Program update

- A — First KEC-executed Simonette well on-stream Sep 2024, outperforming initial expectations
- B — Second well on-stream Nov 2024, cleaning up
- C — Third well planned on-stream Mar 2025

Ⓐ 12-33 Simonette Well	
New well	**1 MTNY**
On-stream	Sep 2024
Average peak 30-day rates	
Equivalent (boe/d)	1,850
Oil & Condensate %	30%

KEC Montney area map

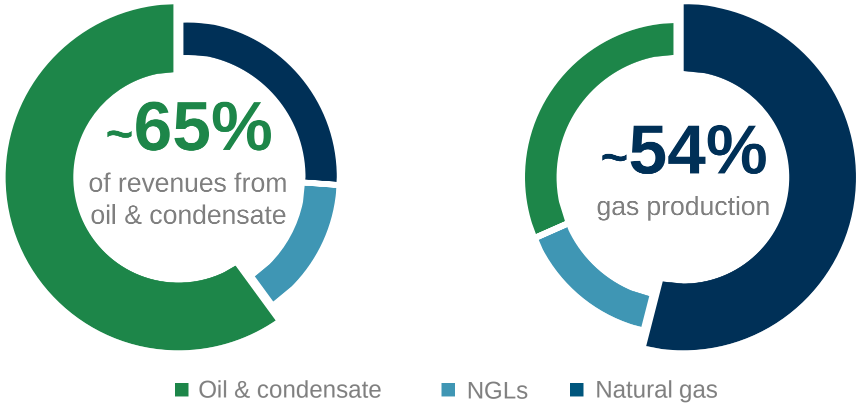


1. Assumes 4 wells per section through single bench of development.

Robust upstream netbacks

1Q-3Q24 revenues

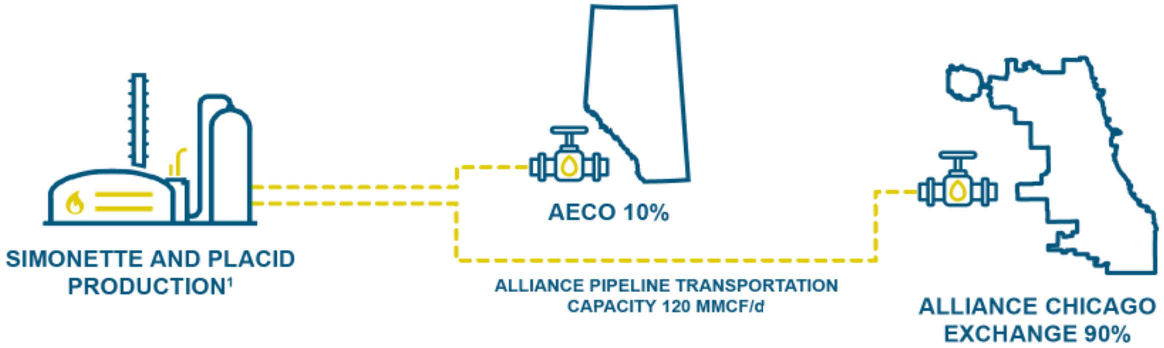
1Q-3Q24 production mix



Condensate production supports revenues in current environment

Majority gas production retains torque to natural gas upside

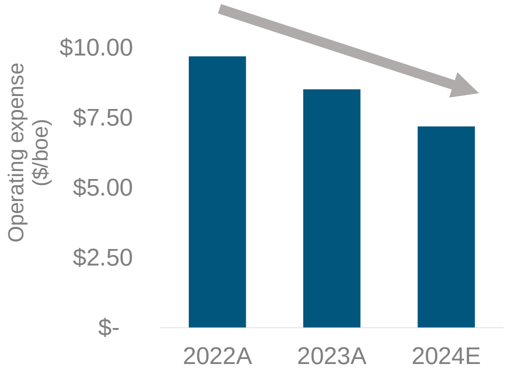
Advantaged gas marketing and strengthened operating costs



>90% of gas production sold on Alliance Pipeline

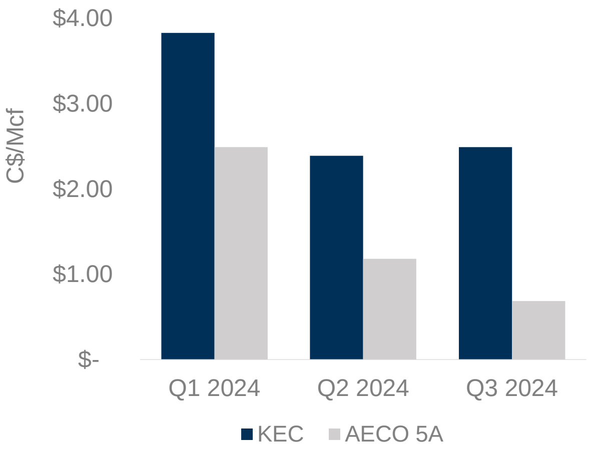
2032 Extended Alliance contract to October 2032 [2]

Strengthening operating costs

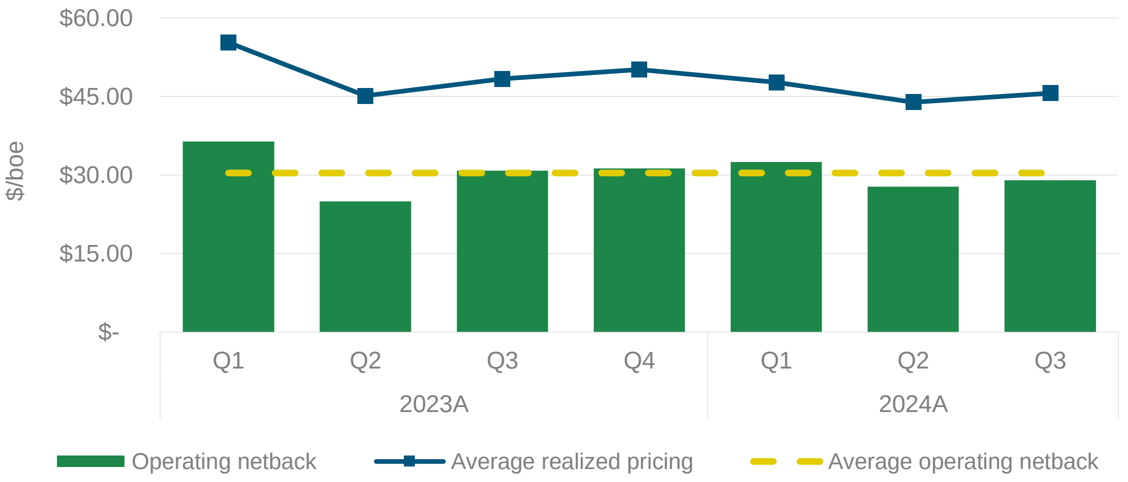


▼26% decrease in per unit operating expenses [1]

Realized natural gas price vs. AECO 5A



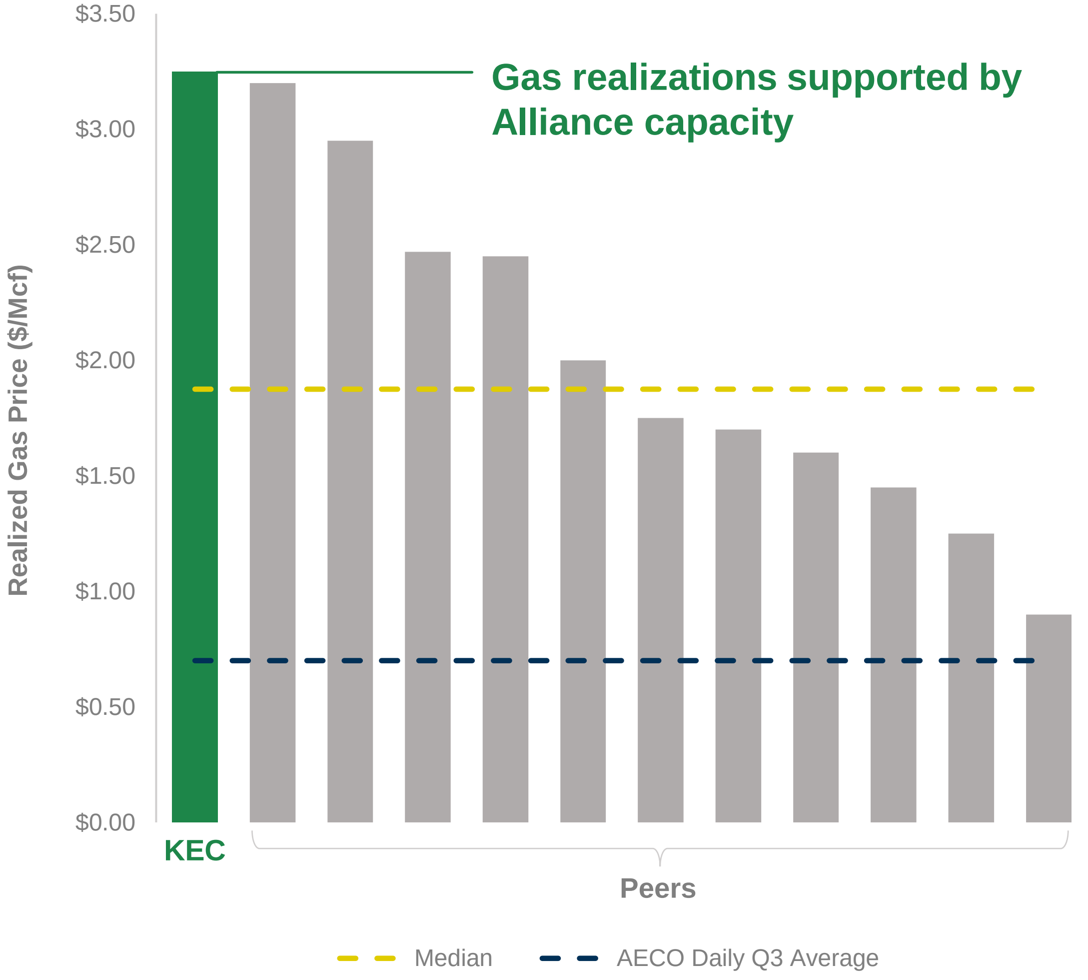
Average quarterly operating netback of ~$30.40/boe since Q1 2023 [3]



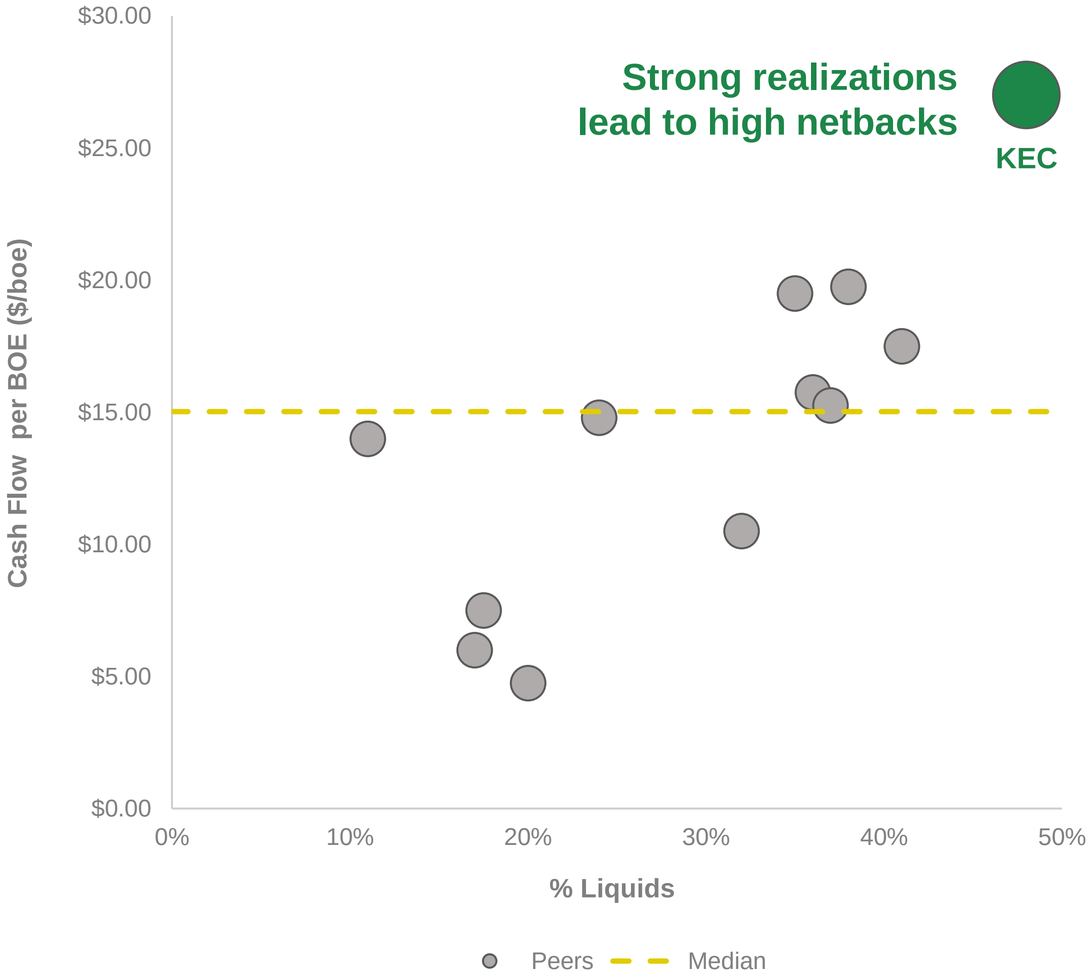
1. Based on actuals and 2024 mid-point of guidance.
2. The Company has extended its commitment on the US segment of the Alliance pipeline until October 2032, with evergreen renewals on the Canadian segment of the Alliance pipeline for one-year terms starting November 2025.
3. See "Non-GAAP financial ratios" found in our September 30, 2024 financial statements and management's discussion and analysis.

High gas realizations and liquids production drive leading netbacks [1, 2]

Realized natural gas price Q3 2024



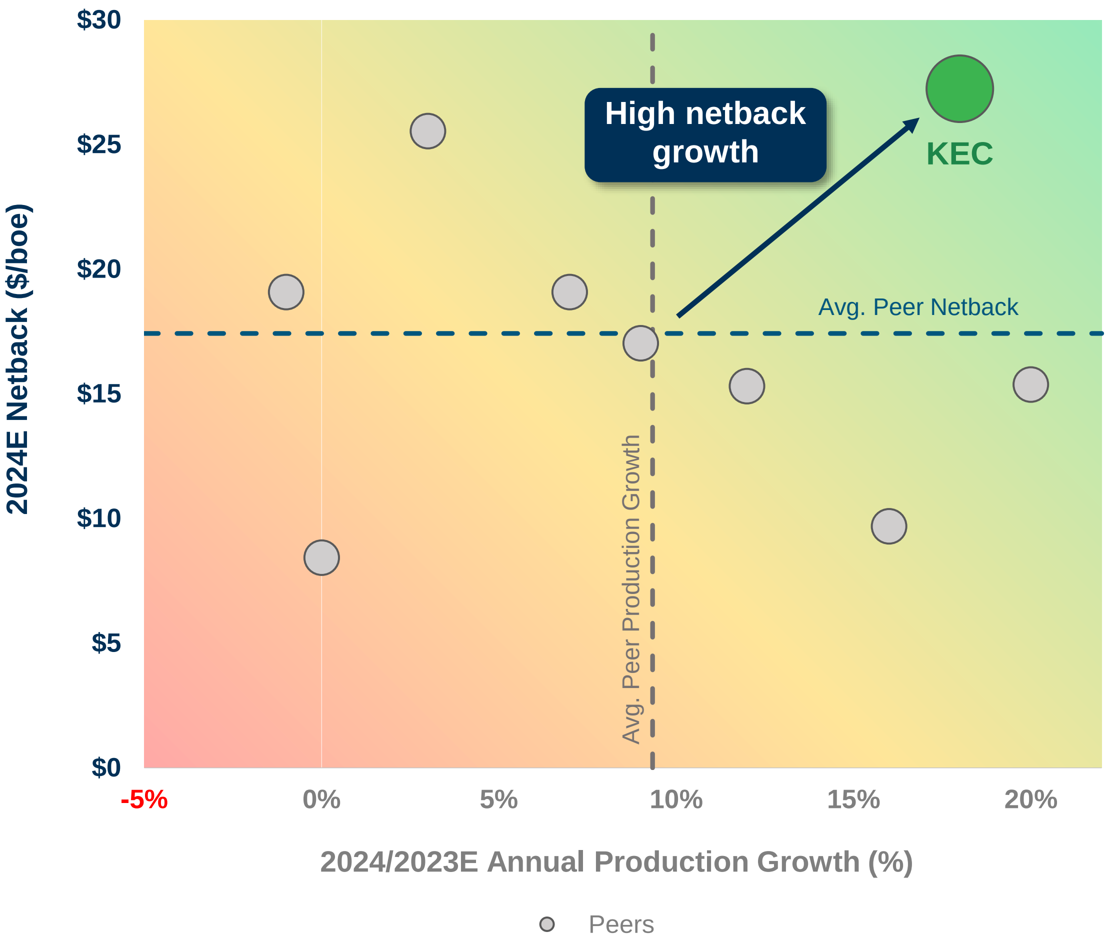
Cash flow per BOE Q3 2024



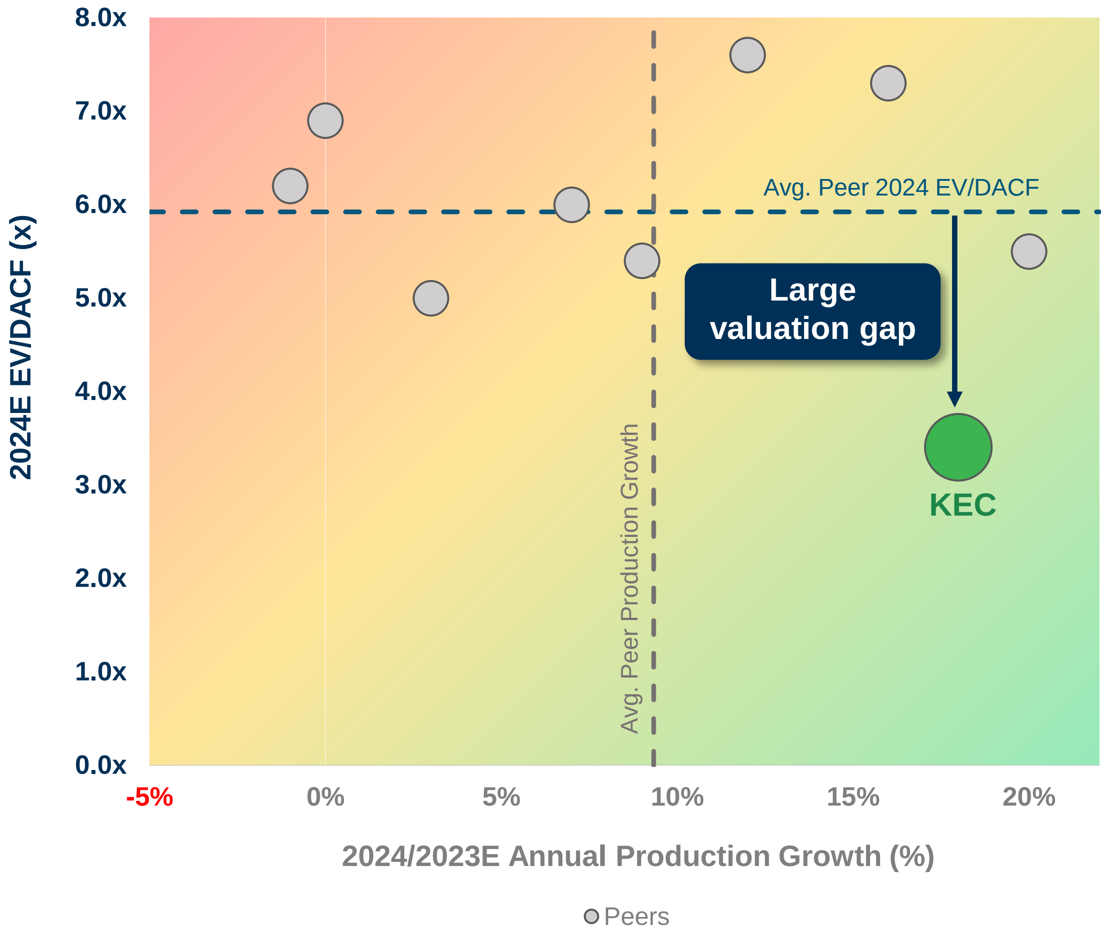
1. Based on Peters & Co. Limited Energy Update dated November 18, 2024.
2. Peer group consists of: Advantage Oil & Gas, ARC Resources Ltd., Birchcliff Energy Ltd., Kelt Exploration Ltd., Logan Energy Corp., NuVista Energy Ltd., Paramount Resources Ltd. Peyto Exploration & Development Corp., Pine Cliff Energy., Spartan Delta Corp., Tourmaline Oil Corp., and Yangarra Resources Ltd.

Upstream comparable trading analysis [1, 2, 3]

ESTIMATED PEER LEADING NETBACKS WITH ROBUST PRODUCTION GROWTH



EV/DACF MULTIPLE REPRESENTS LARGE VALUATION DISCOUNT VERSUS PEERS



1. See "*Non-GAAP financial ratios*".
2. Peer group consists of: Advantage Oil & Gas, ARC Resources Ltd., Birchcliff Energy Ltd., Kelt Exploration Ltd., NuVista Energy Ltd., Peyto Exploration & Development Corp., Paramount Resources Ltd. and Tourmaline Oil Corp.
3. Annual production growth and 2024E EV/DACF estimates based on National Bank of Canada (NBF) Weekly E&P Talking Points comparatives sheet on December 9, 2024, using NBF pricing as of November 4, 2024.

2024 Environment, Social & Governance Highlights [1]

Environmental

On track for

▼50% CO_2

reduction target in vented methane by 2025

(Vented methane of 18,914 tCO_2e in 2023 vs 2022 baseline of 28,177 tCO_2e. Total 2023 emissions increased to 207,675 tCO_2e from 192,179 tCO_2e in 2022 with higher production)

Spent more than

6x

the AER's mandatory ARO expenditures

Advanced

~2GW

of renewable solar and natural gas-fired power projects

Reconnected

>500km

of fish habitat by replacing watercourse crossings on native trout streams

First Canadian company to join the

OGMP
Oil And Gas Methane Partnership 2.0

of the UN Environment Programme for methane tracking and reporting

Social

Raised

~$600K

for Sturgeon Lake Cree Nation wildfire recovery by leading the Industry Partners' Golf Tournament

Zero

lost-time injuries

Welcomed second cohort into our

Indigenous operator

trainee program

Established a

Microloan fund

in partnership with Indian Business Corp. to support small businesses

40% female senior leadership

20% BIPOC senior leadership

5% Indigenous staff base

Governance

Majority independent

board & audit committee

Insider

shareholder ownership

Strong

industry experience

in energy and utilities sector

Code of Conduct

Anonymous

Whistleblower

Policy

22% female board representation

22% BIPOC board representation

1. Includes reporting data for calendar year 2023.

APPENDIX

2024 guidance summary [1]

As of November 5, 2024

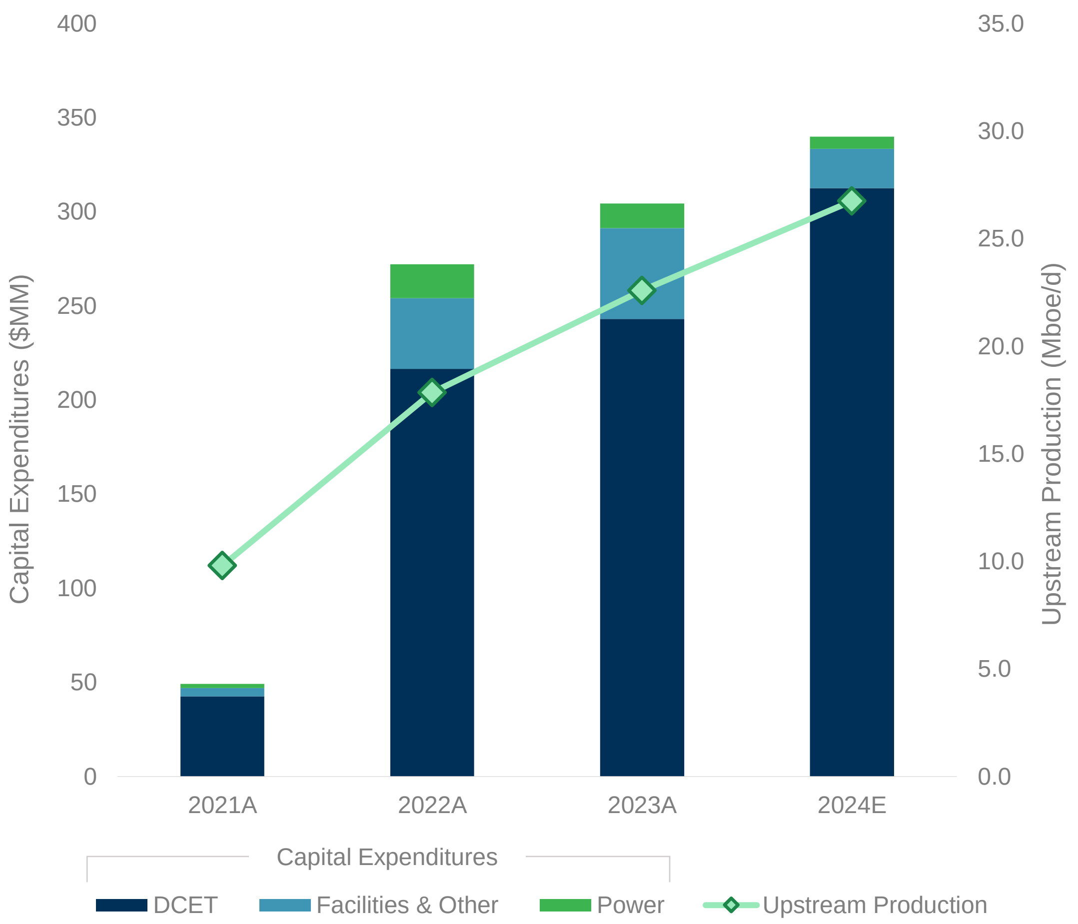
OPERATIONAL & FINANCIAL DETAILS

Average Sales Volumes	(Mboe/d)	**26.0 – 27.5**
Oil & Liquids %	(%)	**45% – 49%**
Royalty Rate (Crown)	(%)	**7% – 10%**
Operating Expense	($/boe)	**$7.25 – $7.75**
Transportation Expense	($/boe)	**$5.50 – $6.00**
Corporate G&A Expense	($MM)	**$23 – $25**
Capital Expenditures – Total	($MM)	**$330 – $350**
Upstream	($MM)	**$325 – $342**
DCET	($MM)	**$305 – $320**
Plant Expansion, Maintenance & Other	($MM)	**$20 – $22**
Power Division [2]	($MM)	**$5 – $8**

2024 SENSITIVITIES [3]

Adjusted Funds Flow from Operations		
US$70/bbl WTI & US$2.50/MMBTU HH	($MM)	**$260 – $280**
Net Debt to Adjusted Funds Flow from Operations		
US$70/bbl WTI & US$2.50/MMBTU HH	(X)	**1.0x – 1.1x**

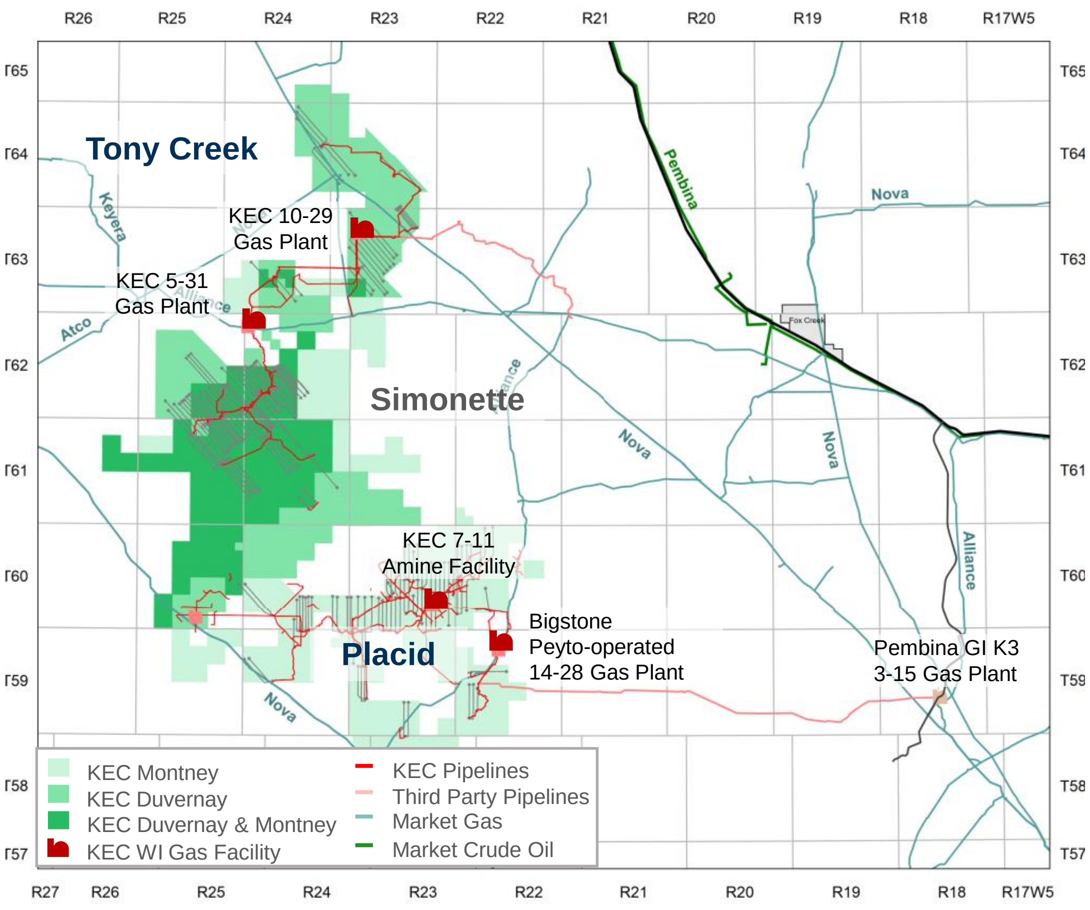
2024 capex focuses on DCET [4]



1. See "*Non-GAAP and other financial measures*".
2. The Company has incurred $3.4 million of costs within the first six months of 2024 prior to recognizing an impairment on the power portfolio (excluding Homestead). Expenditures on impaired projects will be expensed for the remainder of the year. Guidance reflected includes capitalized costs and expensed project development costs.
3. Based on actual realized pricing to date and flat pricing thereafter.
4. 2024 figures based on midpoint of guidance.

Ample infrastructure and takeaway for continued growth

Fox Creek area map



	Simonette	Placid
Infrastructure	**100% KEC owned** gas plants (Best-in-class: >98% run-time)	**100% KEC owned** gathering facility and **39.3% non-operated** working interest in Peyto 14-28 plant (where majority of Montney gas volumes are processed)
Capacity	**Gas: 128 MMcf/d** 10-29 plant: 90 MMcf/d 05-31 plant: 38 MMcf/d **Liquids: 18,000 bbl/d** Includes C5+ stabilization	**Gas: 80 MMcf/d**

Capacity for growth to 40,000 boe/d

KEC's gas plants connect to the Alliance Pipeline and NGTL

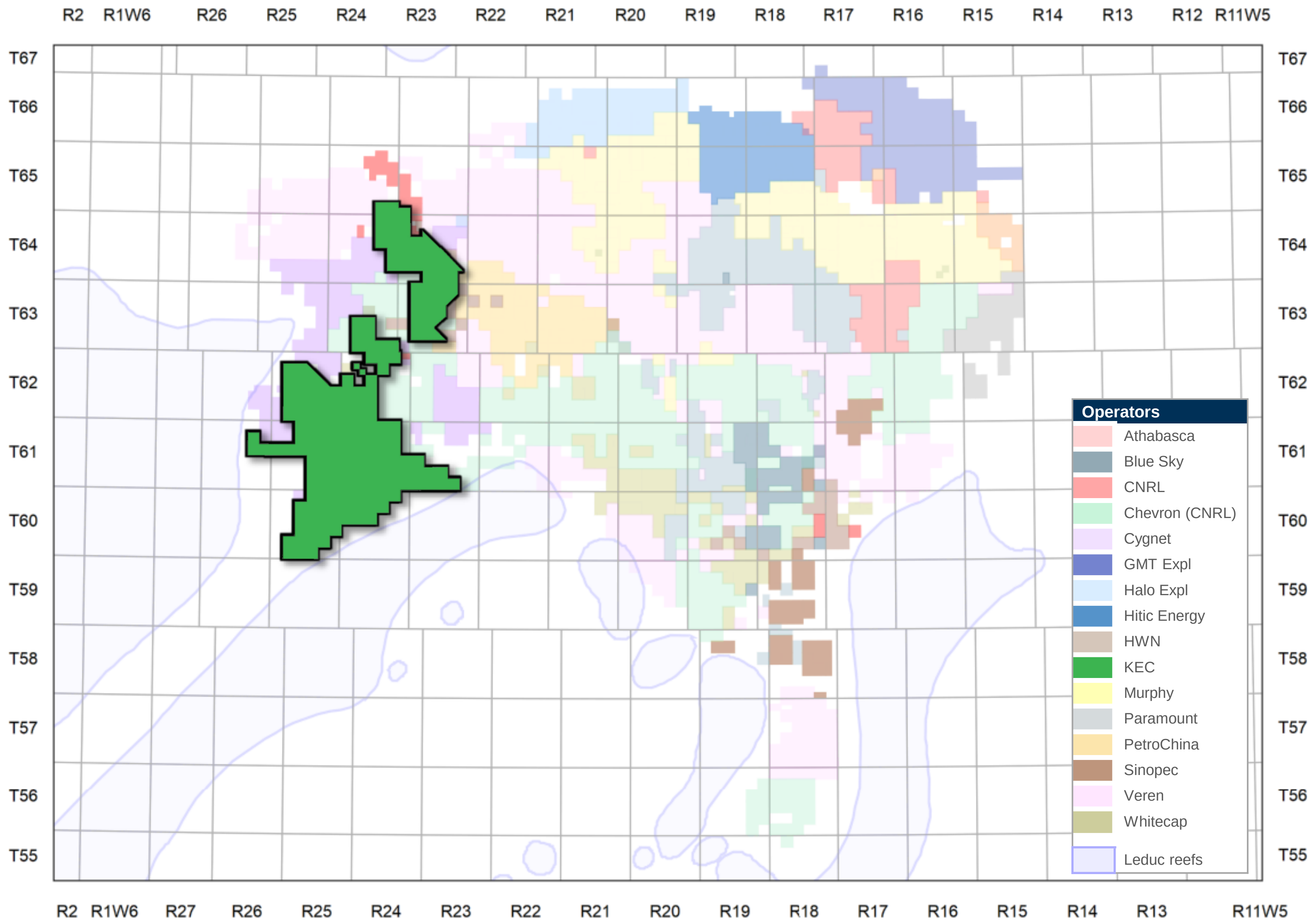
Gas can be sold to Chicago or AECO

120 MMcf/d — **Alliance capacity**
Provides access to US gas markets[1]

30 MMcf/d — **NGTL capacity**
Incremental egress to local markets

1. The Company has extended its commitment on the US segment of the Alliance pipeline until October 2032, with evergreen renewals on the Canadian segment of the Alliance pipeline for one-year terms starting November 2025.

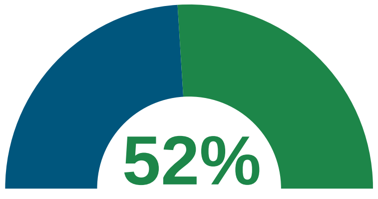
Kaybob Duvernay landscape



203

Drilling locations

Top-tier position in the high-pressure, high-deliverability window of the Duvernay

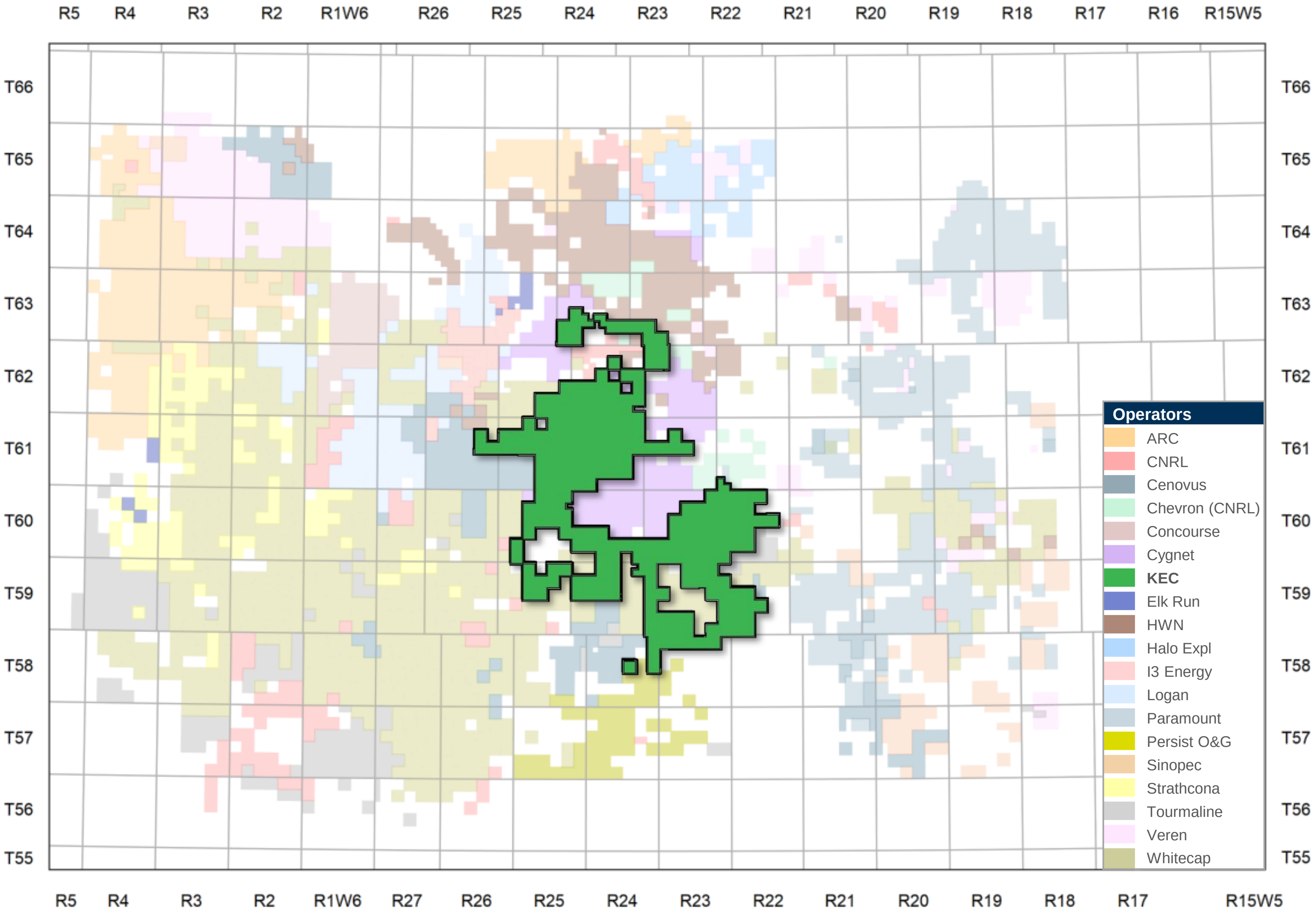


Undeveloped net acres
(~63,000)

- 6 of the top 10 and 39 of the top 100 producing Duvernay wells
- Peer leading operating costs and netbacks
- Owned infrastructure
- Significant egress capacity for gas to US

Source: geologic, geoSCOUT

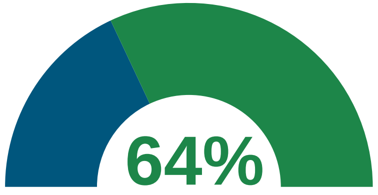
Southern Montney landscape



291

Drilling locations

Large upside potential within the well known Montney formation



Undeveloped net acres
(~92,000)

- Overlays current Duvernay position
- Co-development synergies using existing pad locations improves capital efficiencies

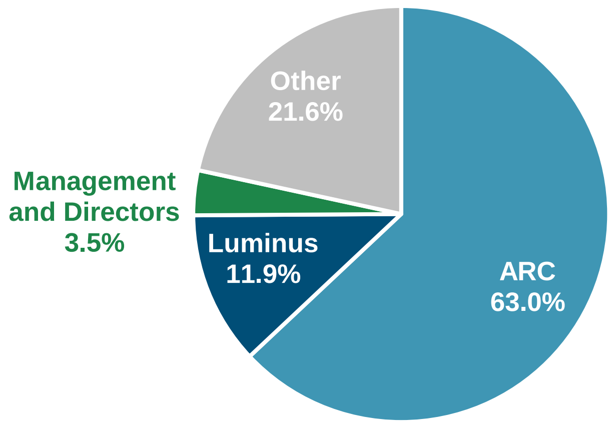
Source: geoLOGIC geoSCOUT

Corporate profile

CAPITALIZATION (AS AT Q3 2024)

Basic Shares Outstanding	(MM)	43.7
Market Capitalization [1]	($MM)	$611
Dilutive Securities [2] **(avg. exercise price of $17.26/sh)**	(MM)	9.6
Net Debt [3]	($MM)	$241
Enterprise Value	($MM)	$852
Credit Facility Limit	($MM)	$400
EDC Letter of Credit Facility Limit	($MM)	$125
Tax Pools	($MM)	$898

COMMON SHARE OWNERSHIP (AS AT Q3 2024)



~78%
insider ownership [4]

ANALYST COVERAGE

ATB Capital Markets	Amir Arif
BMO Capital Markets	Jeremy McCrae
Cormark Securities	TBD
Eight Capital	Phil Skolnick
National Bank	Dan Payne
Peters & Co. Limited	Conrad Bereznicki, Ken Chmela
RBC Capital Markets	Michael Harvey, Maurice Choy

INVESTOR RELATIONS

Email: IR@kiwetinohk.com

CORPORATE CALENDAR

2024YE Results	March 6, 2025

TSX: KEC

1. Market capitalization calculated based on the last trading day of the third quarter (September 30, 2024), share price of $13.98 / share.
2. Includes all units outstanding under the equity-settled incentive plans.
3. Net debt as of September 30, 2024. See "*Non-GAAP and other financial measures*".
4. Insider ownership calculated based on management and directors and shareholders with >10% ownership.

Hedging summary [1]

		4Q24	1Q25	2Q25	3Q25	4Q25	1Q26	2Q26	3Q26	4Q26	1Q27	2Q27
WTI HEDGES												
WTI SWAP VOLUMES	(BBL/D)	2,000	1,583	1,000	917	750	500	500	500	500	-	-
WTI BUY PUT VOLUMES	(BBL/D)	3,833	3,333	3,083	2,583	2,333	1,000	1,000	1,000	1,000	167	-
WTI SELL CALL VOLUMES	(BBL/D)	3,333	3,333	3,083	2,583	2,333	1,000	1,000	1,000	1,000	167	-
WTI SWAP PRICE	(US$/BBL)	$73.91	$73.60	$71.85	$71.69	$71.37	$70.05	$70.05	$70.05	$70.05	-	-
WTI BUY PUT PRICE	(US$/BBL)	$69.35	$68.80	$68.70	$68.45	$68.28	$67.50	$67.50	$67.50	$67.50	$70.00	-
WTI SELL CALL PRICE	(US$/BBL)	$78.25	$77.03	$76.79	$76.29	$76.10	$73.66	$73.66	$73.66	$73.66	$73.18	-
ALLIANCE HEDGES												
HENRY HUB SWAP VOLUMES	(MMBTU/D)	2,500	-	-	-	-	-	-	-	-	-	-
HENRY HUB BUY PUT VOLUMES	(MMBTU/D)	40,833	47,500	37,500	35,833	35,000	30,000	25,000	25,000	23,333	2,500	861
HENRY HUB SELL CALL VOLUMES	(MMBTU/D)	32,500	47,500	37,500	35,833	35,000	30,000	25,000	25,000	23,333	2,500	861
HENRY HUB SWAP PRICE	(US$/MMBTU)	$3.23	-	-	-	-	-	-	-	-	-	-
HENRY HUB BUY PUT PRICE	(US$/MMBTU)	$3.19	$3.15	$3.17	$3.18	$3.21	$3.11	$3.09	$3.09	$3.07	$3.00	$1.00
HENRY HUB SELL CALL PRICE	(US$/MMBTU)	$4.14	$4.38	$4.42	$4.46	$4.58	$4.49	$4.30	$4.30	$4.25	$3.90	$1.30
ALLIANCE REPLACEMENT GAS HEDGES												
BOUGHT AECO A5 SOLD AT HENRY HUB	(MMBTU/D)	30,000	30,000	25,000	25,000	8,333	-	-	-	-	-	-
GDD CHICAGO SOLD AT HENRY HUB	(MMBTU/D)	(30,000)	(30,000)	(25,000)	(25,000)	(8,333)	-	-	-	-	-	-
AECO 5A TO HENRY HUB BASIS	(US$/MMBTU)	($1.33)	($1.35)	($1.36)	($1.36)	($0.45)	-	-	-	-	-	-
GDD CHICAGO TO HENRY HUB BASIS	(US$/MMBTU)	($0.03)	($0.01)	($0.08)	($0.08)	($0.03)	-	-	-	-	-	-
FX												
NOTIONAL SWAPS (MONTHLY AVERAGE)	(US$MM)	$9.0	$16.5	$16.5	$16.5	$16.5	-	-	-	-	-	-
NOTIONAL COLLARS (MONTHLY AVERAGE)	(US$MM)	$5.0	$2.5	$2.5	$2.5	$2.5	-	-	-	-	-	-
FX SWAP RATE	(CAD/USD)	1.33	1.34	1.34	1.34	1.34	-	-	-	-	-	-
FX COLLAR CEILING	(CAD/USD)	1.32	1.33	1.33	1.33	1.33	-	-	-	-	-	-
FX COLLAR FLOOR	(CAD/USD)	1.34	1.38	1.38	1.38	1.38	-	-	-	-	-	-

1. As of November 5, 2024.

Forward-looking statements

Certain statements contained in this presentation constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (collectively, "**forward-looking statements**"). All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "should", "would", and "potential" and similar expressions or statements regarding an outlook are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this presentation should not be unduly relied upon. Events or circumstances may cause actual results to differ materially from those predicted as a result of numerous known and unknown risks, uncertainties and other factors, many of which are beyond the control of the Company. These statements speak only as of the date of this presentation. In addition, this presentation may contain forward- looking statements attributed to third-party industry sources.

Specifically, this presentation contains forward-looking statements pertaining to: upstream production growth; approvals for various projects; value realization on Company projects in the second half of 2024; growth opportunities provided from baseload reinforcement requirements in the Alberta power market; the Company's growth strategy and prospects including the Company's operational and financial guidance for 2024; the anticipated completion of certain wells, the timing thereof and the production therefrom; the anticipated payout of certain wells and well pads and the timing thereof; expectations regarding the Company's plans to drill, equip and tie-in wells; expectations regarding the drilling pace of certain rigs and wells; expectations regarding the development of the Company's Duvernay and Montney inventory; the Company's ability to co-develop Montney inventory with Duvernay in Simonette using existing infrastructure; expectations surrounding approvals related to the Company's 2025 and 2026 budgets; inventory and infrastructure in place to develop upstream resources to 40,000 boe/d and the timing of such development; the Company's ability to achieve its target of 40,000 boe/d and initial capital expenditures, balance sheet capacity, market access, inventory and scale needed to achieve such target; the Company's ability to meet its CAGR targets; expectations relating to the Company's capital expenditures and the resulting growth therefrom; expected free funds flow, production and output; the Company's ability to fill egress commitments; the Company's plans for development of its natural gas-fired and solar generation projects and expectations with respect to future opportunities for other renewable energy projects; the Company's plans for exploration, resource testing, development, exploitation and acquisitions; projections of market prices and costs; access to gas sales on the Chicago market and other market access; nature, timing and development of the Company's capital projects, including the expected financial performance thereof following completion of the development and the commencement of operations, as applicable; estimates of operating netback; the Company's plans with respect to development and operation of its upstream properties, including estimates of production, drilling and completion costs and efficiency improvements; the ability of the Company to achieve its methane reduction targets by 2025; expectations with respect to the Company's financial position; future costs; access to third-party infrastructure; industry conditions pertaining to the crude oil and natural gas industry and the energy transition and renewable power industries; and expectations regarding the Company's power division, carbon hubs and access to diverse markets for its products.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserve values may be greater than or less than the estimates provided herein. Similarly, "type curve" estimates (and all of the components thereof as set forth on slide 14) are also forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that similar wells in the same formation will have similar results and performance. Actual well results may be greater than or less than the estimates reflected in such "type curves" and the differences could be material.

In addition, this presentation contains certain forward-looking information relating to economics for drilling opportunities in the areas that the Company has an interest. Such information includes, but is not limited to, payouts, recycle ratios, reserve life index, anticipated netbacks, EV/DACF and capex ratios which are based on additional various forward-looking information such as production rates, anticipated well performance, the estimated net present value of the anticipated future net revenue associated with the wells, anticipated reserves, anticipated capital costs, anticipated finding, exploration and development costs, anticipated ultimate reserves recoverable, anticipated future realized hedging gains and losses, anticipated future royalties, operating expenses, transportation expenses and anticipated construction and operation of power generation facilities.

Forward-looking statements (continued)

In addition to other factors and assumptions that may be identified in this document, assumptions have been made regarding, among other things: the timing and costs of the Company's capital projects, including drilling and completion of certain wells; costs to abandon wells or reclaim property; the impact of increasing competition; general business, economic and market conditions; the general stability of the economic and political environment in which the Company operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of the operator of the projects that the Company has an interest in to operate in a safe, efficient and effective manner; the ability to negotiate deal structures and terms on the Company's power projects; the ability to maximize shareholder value in the short and long term; future commodity and power prices; currency, exchange, royalty and interest rates; the regulatory framework regarding royalties, taxes, power, renewable and environmental matters in the jurisdictions in which the Company operates; the ability of the Company to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations; the ability of the Company to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms and the capacity and reliability of facilities; anticipated timelines and budgets being met in respect of drilling and completions programs and other operations; the impact of natural disasters, war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukrainian conflict and conflict in the Middle East) on the Company; the ability of the Company to successfully market its products; the Company's operational success and results being consistent with current results and/or expectations; the Company's ability to realize on expectations regarding low supply cost, reliability and efficiency of its power generation portfolio; development and completion of the Company's natural gas-fired and solar power generation projects in a timely and cost-efficient manner and the Company's ability to continue to identify and progress projects for its power generation portfolio; the Company's ability to successfully diversify markets for its upstream business and assets with the Company's power generation portfolio; the Company's ability to market production of oil, condensate, NGL, natural gas, electricity, low-emissions electricity, hydrogen, CO_2 and tax credits and other financial instruments as they emerge and evolve from time to time related to the production of low-emissions electricity and/or hydrogen successfully to customers; the Company's ability to buy and sell hydrocarbon gathering and processing services and carbon capture, utilization and storage services to other parties; the Company's future production levels and future cash flows thereof; the recoverability of the Company's reserves; that the Company will have access to solar and other renewable resources in amounts and at the costs consistent with the amounts and costs expected by the Company for the development projects in its power generation portfolio; the nature of carbon capture technologies and the benefits of their application, including to the Company's proposed projects; future sources of funding for the Company's capital program and the Company's plans for future capital investments; the Company's future debt levels; geological and engineering estimates in respect of the Company's reserves; the geography of the areas in which the Company is conducting exploration and development activities and the access, economic, regulatory and physical limitations to which the Company may be subject from time to time community and stakeholder commitment to sustainable energy sources; the Company's positioning within the sustainable energy or energy transition space; the Company's ability to achieve certain of its ESG initiatives; risks related to the interpretation of, and/or potential claims made pursuant to, the Government of Canada amendments to the deceptive marketing practices provisions of the Competition Act (Canada) regarding greenwashing; expectations regarding access of oil and gas leases in light of caribou range planning; the impact of rising inflation rates and interest rates on the North American and world economies and the corresponding impact on the Company's supply chain, costs and profitability, and on crude oil, NGLs and natural gas prices; the Company's ability to obtain the support of stakeholders other than regulators which may affect the Company's ability to efficiently develop its capital projects including the cost or timing thereof; the legislation and regulations impacting the Company's operations thereof and the interpretation thereof; and the Company's ability to obtain financing necessary for the advancement of the Company's business plan on acceptable terms.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions that have been used. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements as the Company can give no assurance that such expectations will prove to be correct.

Forward-looking statements or information involve a number of risks and uncertainties that could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements or information. These risks and uncertainties include, among other things: the ability of management to execute its business plan; general economic and business conditions; risks of natural disasters, war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing conflict in the Middle East and the Russian-Ukrainian conflict) in or affecting jurisdictions in which the Company operates; the risks of the power and renewable industries; operational and construction risks associated with certain projects; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; risks relating to regulatory approvals and financing; uncertainty involving the forces that power certain renewable projects; uncertainty regarding provincial and federal electricity regulations and policies; the Company's ability to enter into or renew leases; potential delays or changes in plans with respect to power and solar projects or capital expenditures; risks associated with rising capital costs and timing of project completion; fluctuations in commodity and power prices, foreign currency exchange rates and interest rates; inflation and increased pricing and costs for services, personnel and other items; risks inherent in the Company's marketing operations, including credit, health, safety, environmental, market and construction risks and risks associated with existing and potential future lawsuits and regulatory actions against the Company; uncertainties as to the availability and cost of financing; the ability to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms; processing, pipeline and fractionation infrastructure outages, disruptions and constraints; financial risks affecting the value of the Company's investments; and other risks and uncertainties described elsewhere in this document and in Kiwetinohk's other filings with Canadian securities authorities.

Forward-looking statements (continued)

Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties. Additional information on risks, uncertainties and assumptions can be found under "*Risk Factors*" in the Company's annual information form ("**AIF**") for the year ended December 31, 2023, published on the Company's profile on the System for Electronic Document Analysis and Retrieval ("**SEDAR+**") at www.sedarplus.ca.

The forward-looking statements and information contained in this document speak only as of the date of this document and the Company undertakes no obligation to publicly update or revise any forward-looking statements or information, except as expressly required by applicable securities laws.

This presentation includes information obtained from independent industry publications, government publications, market research reports and other published independent sources. Such publications and reports generally state that the information contained therein has been obtained from sources believed to be reliable. Although the Company believes these publications and reports to be reliable, it has not independently verified any of the data or other statistical information contained therein, nor has it ascertained or validated the underlying economic or other assumptions relied upon by these sources.

Future-Oriented Financial Information

This document contains information that may constitute future-orientated financial information or financial outlook information (collectively, "**FOFI**") about the Company's prospective financial performance, financial position or cash flows, all of which is subject to the same assumptions, risk factors, limitations and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on FOFI. The Company's actual results, performance and achievements could differ materially from those expressed in, or implied by, FOFI. These projections may also be considered to contain future oriented financial information or a financial outlook. See above and "*Risk Factors*" in the Company's AIF for the year ended December 31, 2023, published on the Company's profile on SEDAR+ at www.sedarplus.ca for a further discussion of the risks that could cause actual results to vary. The future oriented financial information and financial outlooks contained in this presentation have been approved by management as of the date of this presentation. The Company has included FOFI in order to provide readers with a more complete perspective on the Company's future operations and management's current expectations relating to the Company's future performance. Readers are cautioned that such information may not be appropriate for other purposes. Unless required by applicable laws, the Company does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Reserves and oil & gas disclosure

Reserves estimates in this presentation are based on the evaluation prepared by McDaniel as set out in its report effective as of December 31, 2023 (the "**McDaniel Reserves Report**"), which was prepared in accordance with National Instrument 51-01 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and the Canadian Oil and Gas Evaluation Handbook. The McDaniel Reserves Report was based on the average forecast pricing of McDaniel, GLJ Ltd. and Sproule Associates Limited and inflation rates and foreign exchange rates as at January 1, 2024, which is available on McDaniel's website at www.mcdan.com. The discounted and undiscounted net present value of future net revenues attributable to the Company's reserves do not represent the fair market value of the Company's reserves.

	CRUDE OIL / CONDENSATE (MMBBL)	NGLS (MMBBL)	NATURAL GAS (BCF)	TOTAL (MMBOE)[1]
Proved Developed Producing	10.5	4.8	122.2	35.7
Total Proved	34.9	14.9	351.9	108.4
Total Proved plus Probable	61.0	26.3	629.2	192.2

[1] Disclosure of reserves on a per boe basis in this presentation consists of the constituent product types and their respective quantities disclosed in this table.

Barrel of Oil Equivalency

For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. The term "boe" may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas per barrel of oil (6 mcf:1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from an energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.

Emissions

There is no single standard system that applies across companies for compiling and calculating the quantity of greenhouse gas emissions ("**GHG Emissions**") and other sustainability metrics attributable to the Company's operations. Accordingly, such information may not be comparable with similar information reported by other companies. The Company's Scope 1 and Scope 2 GHG Emissions are calculated using locally regulated methodology or locally recognized industry standards as well as Global Waste Research Institute/World Business Council for Sustainable Development GHG Protocol. The Company may change its policies for calculating these GHG emissions and other sustainability metrics in the future without prior notice.

Industry Specific Terminology

This presentation contains certain metrics commonly used in the oil and gas industry, such as "30-day rates", "IRRs" "operating netback", "payout", "peak rates", "recycle ratio", "reserve life index", "reserves replacement" (excluding A&D), "F&D", "FD&A" and "capital efficiency". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies. Therefore, they should not be used by investors to make such comparisons. The Company calculates these metrics according to the descriptions below and in the "Non-GAAP and other financial measures" section of this presentation. 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.

Reserve replacement (excluding A&D) is calculated by dividing: (i) the net changes to reserves in such reserves category from the prior period from extensions & improved recovery, technical revisions, economic factors, acquisitions, and dispositions, expressed in boe; by (ii) the actual annual production for 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.

Reserve life index is calculated by dividing: (i) the reserves by category, expressed in boe; by (ii) the annualized fourth quarter average production rate, expressed in boe/d. It is an indication of how long an exploration and production company can sustain current rates of production based on proved reserves.

Recycle ratio is calculated by dividing the netback (a non-GAAP financial measure) per boe for the period by the F&D costs or the FD&A 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.

Reserves and oil & gas disclosure (continued)

Recycle ratio is calculated by dividing the netback (a non-GAAP financial measure) per boe for the period by the F&D costs or the FD&A 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.

Payout, Short-Term Production rates and IRR

This presentation contains disclosure regarding the expected payout of certain of the Company's wells and well pads. Well payout means the anticipated time period of production from a well or well pad required to fully pay for the DCET costs of such well or well pad. Payout is achieved when the revenues from the production of a well or well pad, less the associated royalties, transportation, operating and other costs, are equal to the DCET costs for the well or well pad. Management considers well payout estimates an important measure to evaluate its operational performance and capital allocation processes. Well payout estimates are, however, subject to numerous assumptions and risks and actual well payout time periods could, as a result, be materially different than anticipated. Accordingly, investors should not place undue reliance on well payout estimates. The well payout estimates contained herein are based on the following principal assumptions in addition to assumptions regarding well performance being consistent with management's expectations: (1) commodity prices set forth herein, and exclusive of the Company's current commodity hedges, (2) the well pad DCET cost estimates set forth herein and (3) the 2023 annual royalty and cost estimates set forth herein.

References in this presentation to "peak rates", "IRR", "<30 day rates" and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter, and are therefore not indicative of long term performance or recovery. Investors are encouraged not to place reliance on such rates when assessing the Company's aggregate production or long-term production.

Drilling Locations

This presentation discloses drilling locations or inventory. The table below shows the total locations broken down into proved locations, probable locations and unbooked locations. Proved locations and probable locations are derived from McDaniel's reserves evaluation as of December 31, 2023, and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources.

	TOTAL MONTNEY	TOTAL DUVERNAY	TOTAL COMPANY
PROVED LOCATIONS, NET	20	73	93
PROBABLE LOCATIONS, NET	16	42	58
UNBOOKED LOCATIONS, NET	255	88	343
TOTAL LOCATIONS, NET	291	203	494

Unbooked locations consist of drilling locations that have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production, and reserves information. There is no certainty that the Company will drill all of these drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources, or production. The drilling locations on which the Company drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and, if drilled, there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Reserves and oil & gas disclosure (continued)

Production and Production Type Information

References to petroleum, crude oil, natural gas liquids, natural gas and average daily production in this presentation refer to the light and medium crude oil, tight crude oil, conventional natural gas, shale gas and NGLs product types, as applicable, as defined in NI 51-101.

NI 51-101 includes condensate within the NGLs product type. The Company has disclosed condensate as combined with crude oil and separately from other NGLs since the price of condensate as compared to other NGLs is currently significantly higher, and the Company believes that this crude oil and condensate presentation provides a more accurate description of its operations and results therefrom. Crude oil therefore refers to light oil, medium oil, tight oil, and condensate. NGLs refers to ethane, propane, butane, and pentane combined. Natural gas refers to conventional natural gas and shale gas combined.

Type Well Production and Estimates

This presentation contains reference to a rich gas “type curve”, production and economics. There is no guarantee that the Company will achieve the expected or similar results, capital costs and return costs per well. In addition, any references to initial production rates therein are useful for illustrating expected well results in the first year, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or ultimate recovery.

Non-GAAP and other financial measures

Throughout this document and in other materials disclosed by the Company, the Company uses various specified financial measures including "non-GAAP financial measures", as defined in National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure ("**NI 52-112**") and explained in further detail below, including "capital expenditures", and "operating netback" (collectively, "**Non-GAAP Measures**"). The most directly comparable GAAP measure to capital expenditures is "cash flow used in investing activities". The most directly comparable GAAP measure to operating netback is "commodity sales from production".

The Non-GAAP Measures presented in this document should not be considered in isolation or as a substitute for performance measures prepared in accordance with IFRS and should be read in conjunction with the Company's Condensed Consolidated Interim Financial Statements as at and for the nine months ended September 30, 2024 (the "**Financial Statements**") and Management's Discussion and Analysis for the nine months ended September 30, 2024 ("**MD&A**"). Readers are cautioned that these Non-GAAP Measures do not have standardized meanings and should not be used to make comparisons between Kiwetinohk and other companies. See the heading "Non-GAAP and other financial measures" in the Company's MD&A, available on SEDAR+ at www.sedarplus.ca and incorporated by reference into this presentation, for a detailed analysis, calculation and reconciliation of the Non-GAAP Measures.

Supplementary Financial Measures

The presentation contains a number of supplementary financial measures, including net present value ("**NPV 10**", "**NPV 15**" and "**NPV 20**"), which do not have standardized meaning or a standard method of calculation and therefore may not be comparable to similar measures used by other companies. Such metrics have been included to provide users with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to performance in previous periods. Therefore, such metrics should not be unduly relied upon. NPV 10, NPV 15 and NPV 20 are the differences between the present value of cash inflows and the present value of cash outflows over a period of time at a 10%, 15% and 20% discount rate, respectively. Management uses these finance metrics for its own performance measurements and to provide investors with measures to compare the Company's economic returns and operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from these metrics, as presented herein, should not be relied upon for investment or other purposes.

This presentation contains supplementary financial measures expressed as: (i) adjusted funds flow, operating expenses and transportation on a $/boe basis and (ii) royalty rate. Metrics presented on a $/boe basis are calculated by dividing the respective measure, as applicable, over the referenced period by the aggregate applicable units of production (boe) during such period.

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

Non-GAAP financial ratios

Capital efficiency, presented on a $/boe basis is a non-GAAP ratio within the meaning of NI 52-112 as it has "capital expenditures", a Non-GAAP Measure as, a component. This measure is not a standardized measure under IFRS and might not be comparable to similar financial measures presented by other companies. This measure should not be considered in isolation or construed as an alternative to its most directly comparable measure disclosed in the Company's Financial Statements or other measures of financial performance calculated in accordance with IFRS.

Capital efficiency represents the capital spent to add new or incremental production and is calculated by dividing such capital expenditures by the current rate of the new or incremental production, expressed as a dollar amount per flowing volume of a product ($/boe/d). The Company considers capital efficiency a key measure in evaluating its performance, as it provides management and investors with a means of analyzing the financial return on capital deployed.

F&D costs are calculated by dividing: (i) capital expenditures, excluding green energy projects (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.

FD&A costs are calculated by dividing: (i) capital expenditures and net acquisitions, excluding green energy acquisitions (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, economic factors, acquisitions, and dispositions, expressed in boe. F&D costs and FD&A 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, acquisitions net of dispositions (for FD&A only), and reserve additions.

Operating netback per boe is a non-GAAP ratio within the meaning of NI 52-112 as it has "operating netback", a Non-GAAP Measure as, a component. This measure is not a standardized measure under IFRS and might not be comparable to similar financial measures presented by other companies. Operating netback per boe is calculated as operating netback divided by total production for the period as measured by boe. See the heading "Non-GAAP and other financial measures" in the Company's MD&A, available on SEDAR+ at www.sedarplus.ca and incorporated by reference into this presentation, for a detailed analysis, calculation and reconciliation of operating netback per boe.

Capital management measures

Adjusted funds flow from operations, free funds flow, net debt and net debt to adjusted funds flow from operations are capital management measures that may not be comparable to similar financial measures presented by other companies. These measures should not be considered in isolation or construed as alternatives to their most directly comparable measure disclosed in the Financial Statements or other measures of financial performance calculated in accordance with IFRS. See the headings "Non-GAAP and other financial measures" in the Company's MD&A, available on SEDAR+ at www.sedarplus.ca and incorporated by reference into this presentation, for a detailed analysis, calculation and reconciliation of these capital management measures. The most directly comparable financial measure to each of these capital management measures disclosed in the Financial Statements is cash flow from operating activities.