Corporate Presentation

February 2025

Bringing Energy To Our World – **The Right Way**

veren

Veren at a Glance

Capital Markets Summary

Shares Outstanding	612 million
Market Capitalization	$4.6 billion
Net Debt	$2.5 billion
Enterprise Value	$7.1 billion

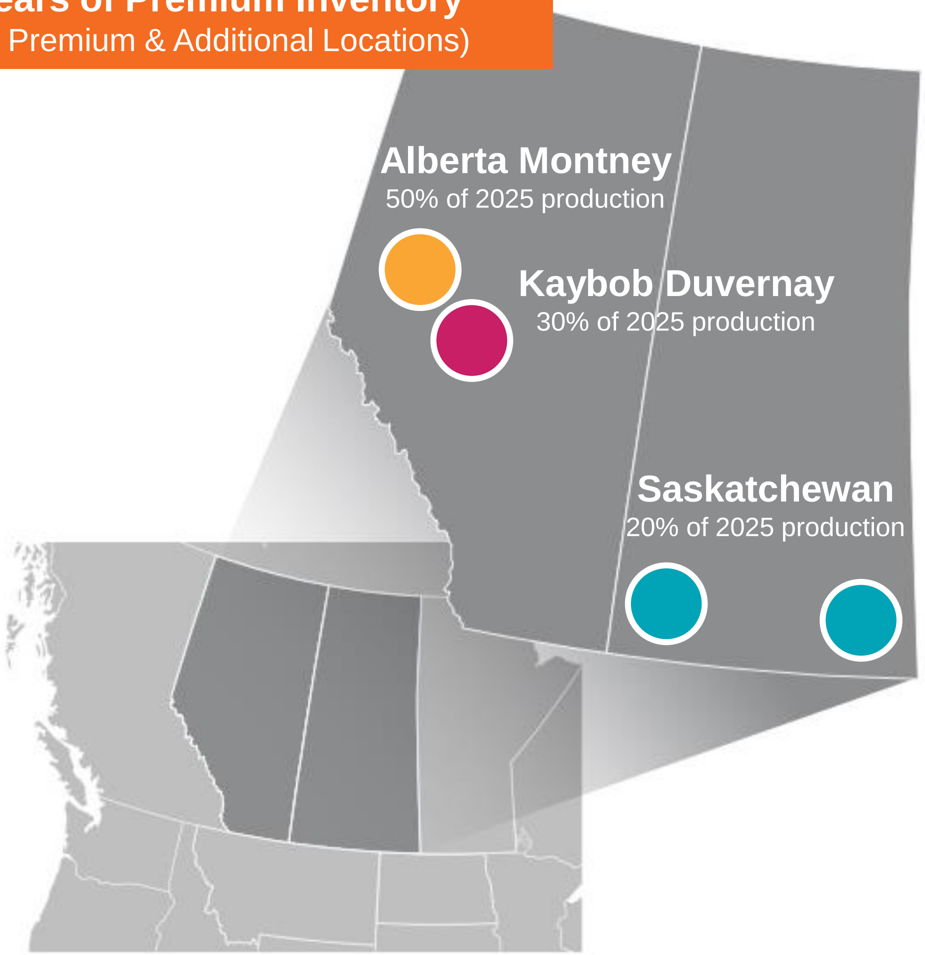
2025 Outlook

Annual Average Production	188,000 - 196,000 boe/d (~65% Liquids)
Development Capital Expenditures	$1.48 - $1.58 billion
Excess Cash Flow (US$70 - US$75 WTI)	$625 - $825 million
YE D/CF (US$70 - US$75 WTI)	0.8 - 0.9x

Return of Capital

Quarterly Base Dividend	$0.115/share (6.1% Annual Yield)
Total Return of Capital (Dividends & Share Repurchases)	60% (% of Excess Cash Flow)

~20 Years of Premium Inventory
(>5,000 Premium & Additional Locations)



Premium inventory is based on management's estimates of established, delineated and well-defined locations with an estimated payback period of less than two years based on mid-cycle pricing.
Net debt as at December 31, 2024. 2025 excess cash flow and YE D/CF assume $2.25/Mcf AECO and CAD/USD FX of $0.71. D/CF (net debt to annualized funds flow), funds flow, development capital expenditures, enterprise value, net debt, excess cash flow, base dividends and total return of capital are specified financial measures - refer to Specified Financial Measures. Capital markets data as at February 19, 2025. Total inventory based on YE 2024 locations.

2024 Highlights & Outlook

Significant excess cash flow of $642MM, driven by focused development of high-quality assets

Reduced net debt by 35% through excess cash flow and proceeds from dispositions

Expect to generate **excess cash flow of $625MM - $825MM in 2025** (US$70/bbl to US$75/bbl WTI)

Returned $386MM, or 60% of excess cash flow in dividends & share repurchases

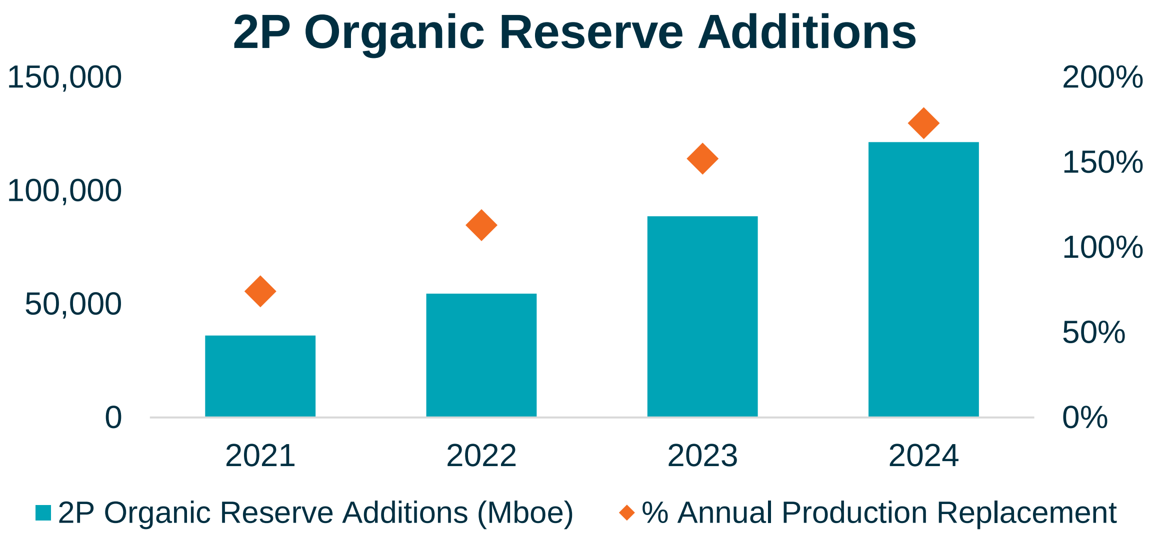
Replaced 173% of 2024 production on 2P basis, driven by additions in the Alberta Montney

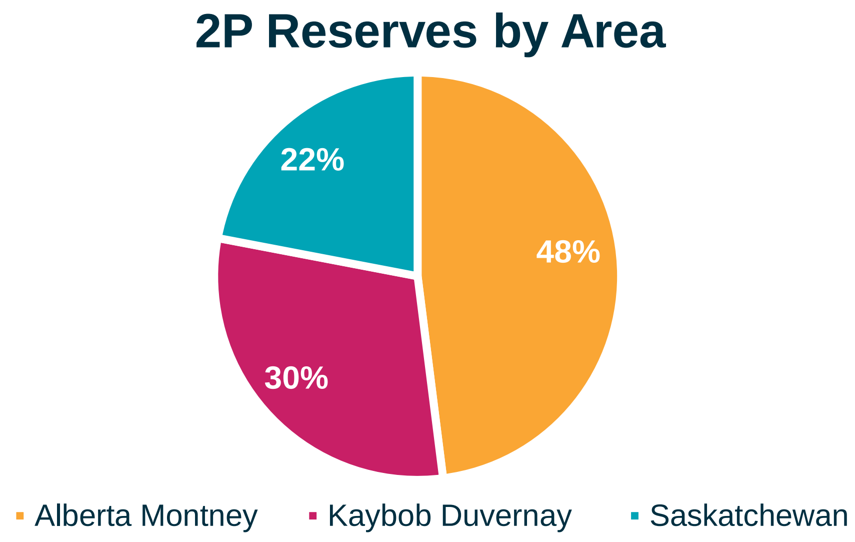
Achieved **responsibly sourced gas certification** under EO100 for Alberta Montney gas sites

EO100: Equitable Origin's Standard for Responsible Development. 2025 excess cash flow assumes $2.25/Mcf AECO and CAD/USD FX of $0.71.

2024 Reserves Highlights

- **Strong organic reserve additions of 121.4 MMboe on a 2P basis**, **replacing 173%** of 2024 annual production
  - **Alberta Montney asset contributed 65%** of the additions
  - Replaced 161% and 114% on 1P and PDP basis, respectively
- **2P reserve life index of ~16 years** based on mid-point of 2025 annual average production guidance
- **Generated 2P recycle ratio of 2.1x** based on F&D costs, including change in FDC, of $17.65/boe

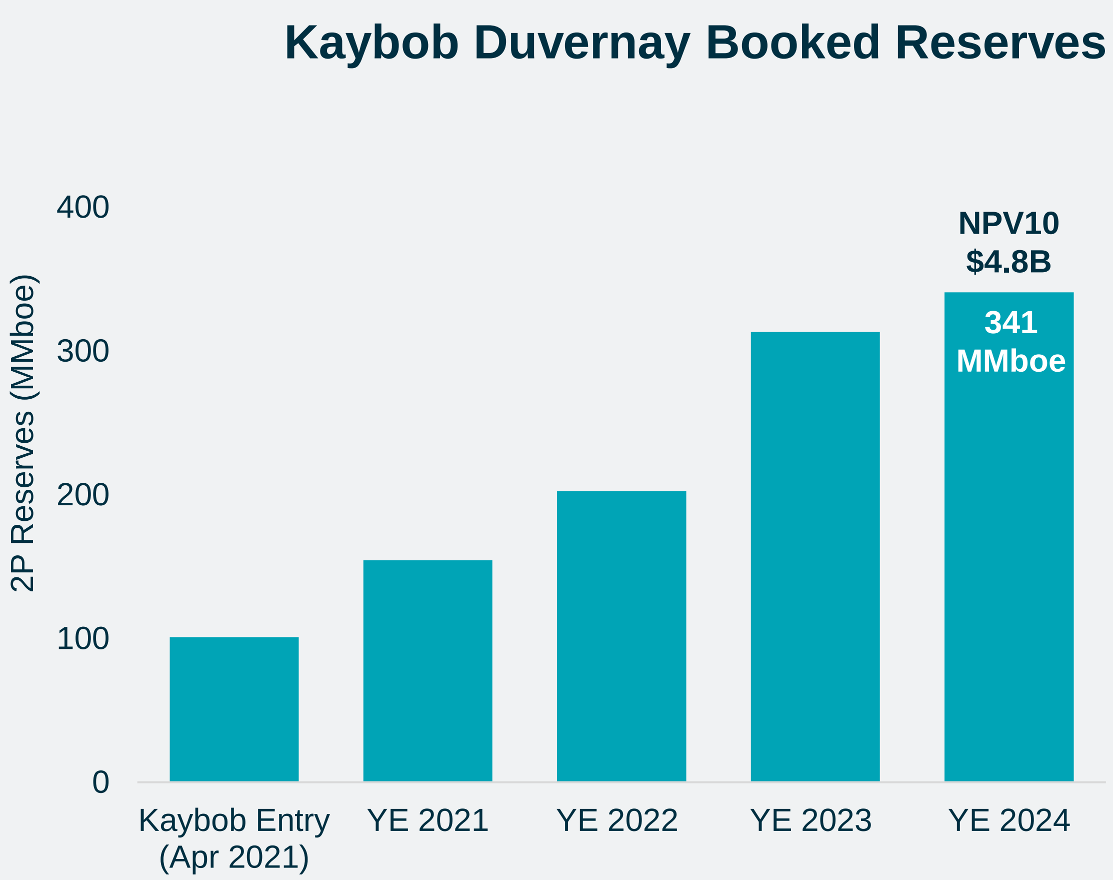


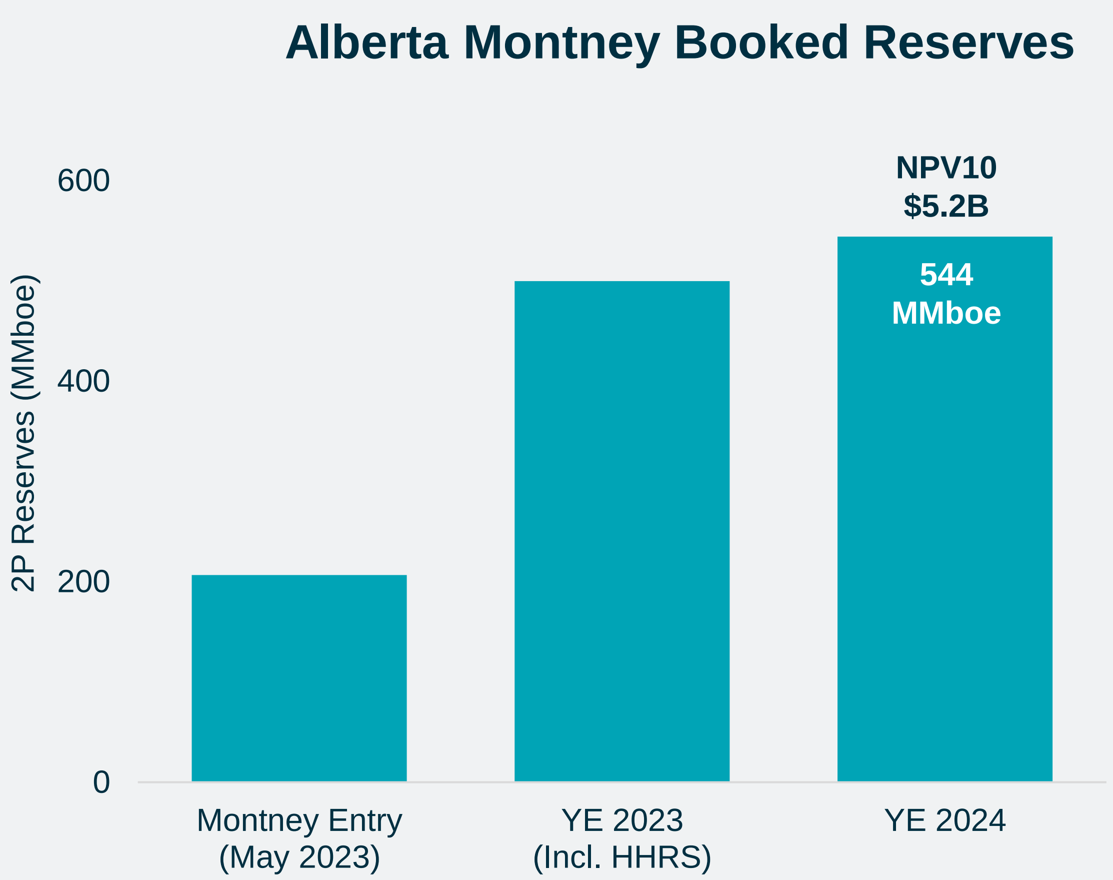


Achieved highest 2P reserve replacement in the last five years in 2024

Organic reserve additions exclude acquisitions and dispositions.
2P: proved plus probable. 1P: proved. PDP: proved developed producing. F&D: finding and development. FDC: future development capital. 2P recycle ratio is based on an operating netback of $36.83/boe in 2024.

Value Creation in the Kaybob Duvernay & Alberta Montney





>65% of total premium drilling locations in the Kaybob Duvernay and Alberta Montney remain unbooked

NPV10 values based on independent engineers reserves and price forecasts.
YE 2024 reserves include 200 net booked proved plus probable (2P) locations in the Kaybob Duvernay and 431 net booked 2P locations in the Alberta Montney as assigned by independent reserves evaluator McDaniel as at December 31, 2024.

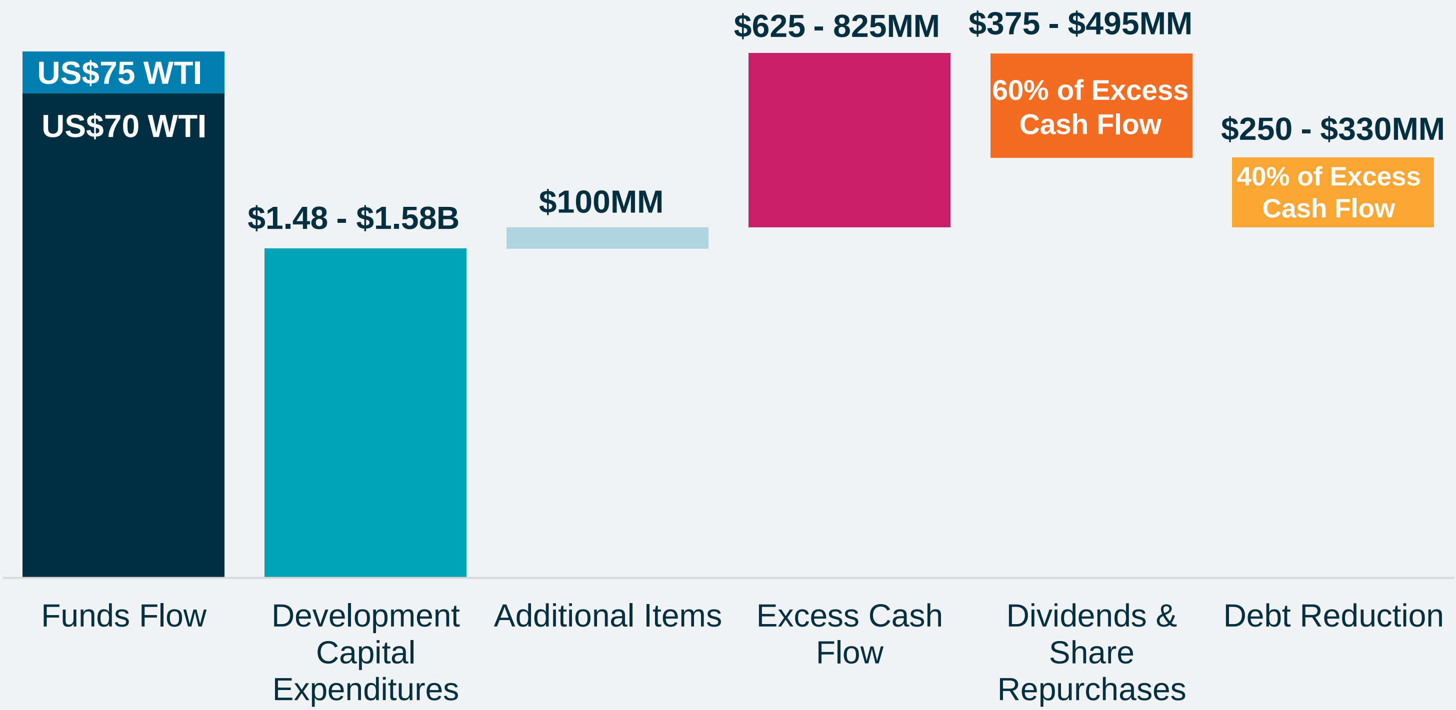
Returns-Focused 2025 Budget

2025 Budget Highlights

- Generate **significant excess cash flow** which is directed to **shareholder returns** & **debt reduction**
- **85%** of 2025 budget is **allocated to Alberta Montney and Kaybob Duvernay**
- Includes incremental capital for facilities projects in the Alberta Montney to **increase capacity**
- A portion of **capital allocated to long-term projects**, such as decline mitigation and environmental initiatives

2025 Budget Summary

Generating annual average production of 188,000 - 196,000 boe/d (65% oil & liquids)



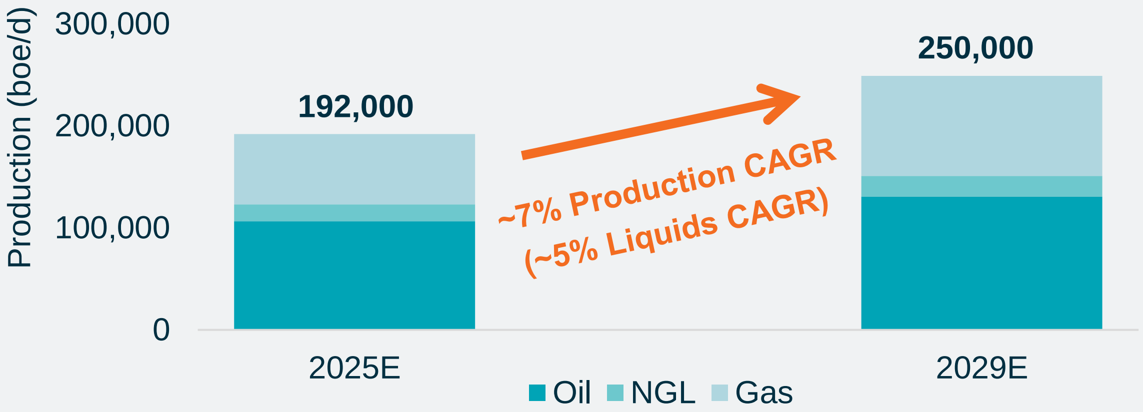
Retain flexibility to lower overall capital budget and allocation in response to weakness in commodity prices

2025 metrics assume $2.25/Mcf AECO and CAD/USD FX of $0.71.
Additional items include capitalized administration, reclamation activities, payments on lease liability and other items, excluding net acquisitions and dispositions.

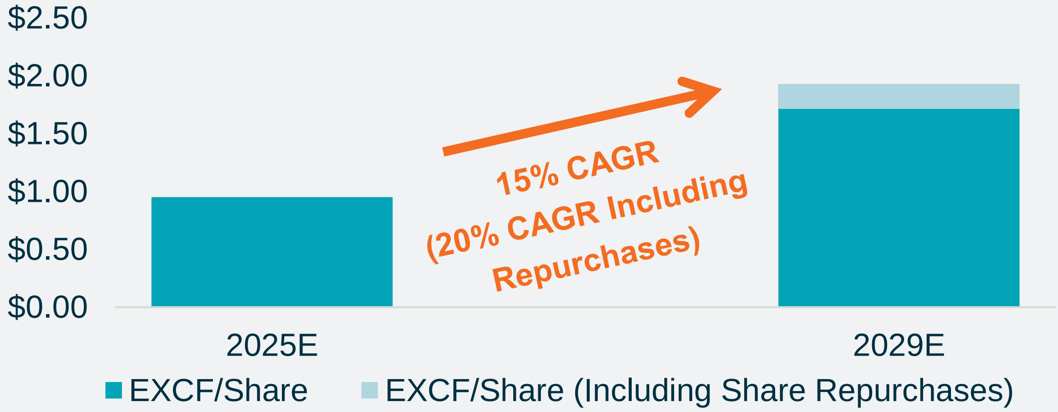
Strong & Returns-Focused 5-Year Plan

Disciplined Growth

Based on development capital expenditures of $1.48 - $1.58B



Significant Excess Cash Flow Generation



Key 5-Year Metrics

(US$65 - US$70 WTI)

Cumulative Excess Cash Flow (After-tax)	$3.4 - $4.2B
Cumulative Return of Capital to Shareholders	$2.0 - $2.5B
Net Debt / Funds Flow (Period End)	0.3x - 0.4x
Percentage of Market Cap Generated in Excess Cash Flow	70% - 90%

All figures are approximates. Key 5-year metrics assume $2.25/mcf AECO for 2025, $3.00/mcf AECO for 2026-2029 and CAD/USD FX of $0.71 for 2025-2029 for the US$70 WTI case and $0.70 for the US$65 WTI case.
Excess cash flow per share - diluted (EXCF/share) is a specified financial measure - refer to Specified Financial Measures.
Excess cash flow per share - diluted CAGR (compound annual growth rate) including share repurchases assumes EV/DACF kept unchanged over 5-year plan for repurchases. 2025E production is based on the mid-point of guidance range.
Outlook is derived by utilizing, among other assumptions, historical production performance. Forecasts beyond 2025 have not been finalized and are subject to a variety of factors including prior year's results.

Commitment to Delivering Shareholder Returns

Track Record of Returning Capital

- Updated return of capital **framework introduced in Q3 2022**
  - **Returned ~$1.3B to shareholders**, including >$650MM in dividends and >$600MM in share repurchases
- Consistently **returning 60% of annual excess cash flow**
- **Plan to increase percentage allocation** of excess cash flow over time as the balance sheet strengthens further
- **Prioritizing share buybacks** as the tool for additional returns

Return of Capital Framework

Funds Flow

(-) Development Capital Expenditures & Additional Items

Excess Cash Flow

↓

Current Return of Capital Outlook ~60%

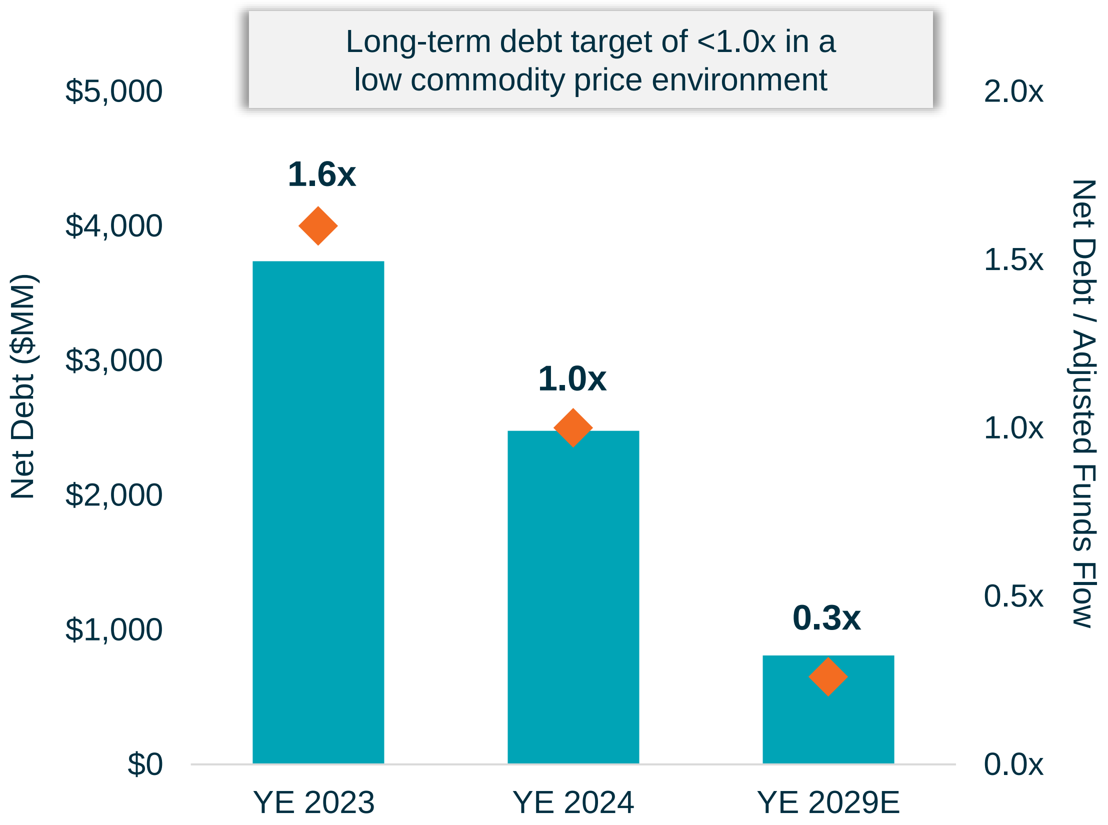
(Dividends & Share Repurchases)

Disciplined capital allocation driving significant excess cash flow & supporting shareholder returns

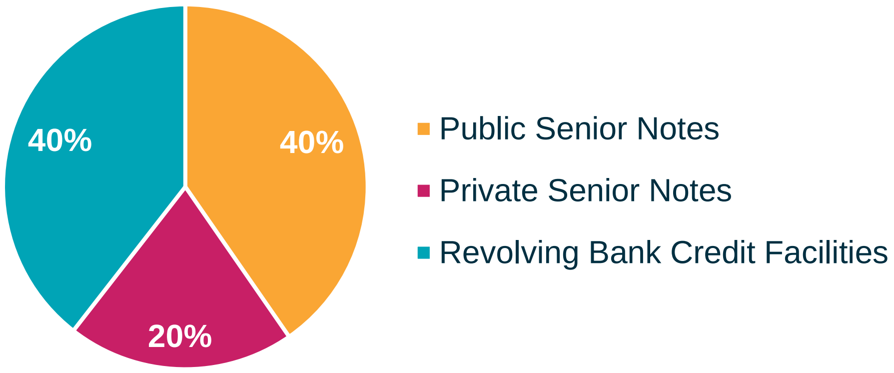
Additional items include capitalized administration, reclamation activities, payments on lease liability and other items, excluding net acquisitions and dispositions.

Strong Balance Sheet & Financial Flexibility

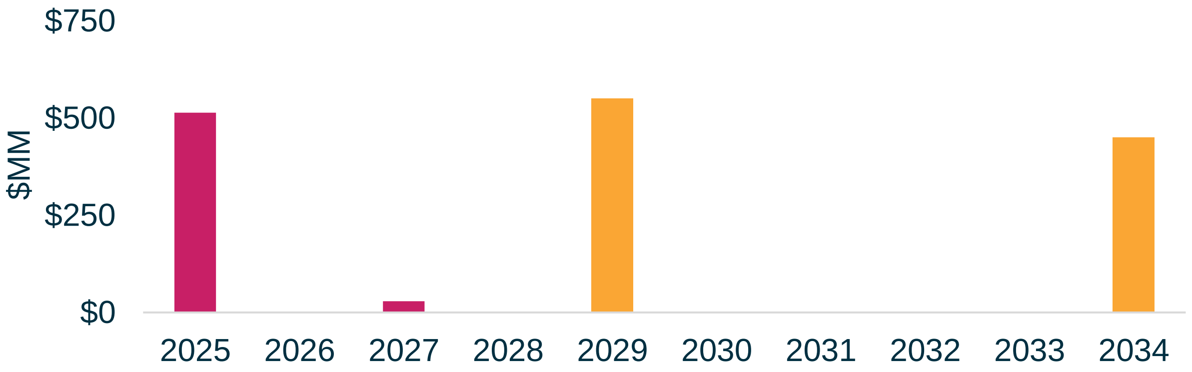
Net Debt Outlook



YE 2024 Debt Composition



Senior Note Maturity Schedule

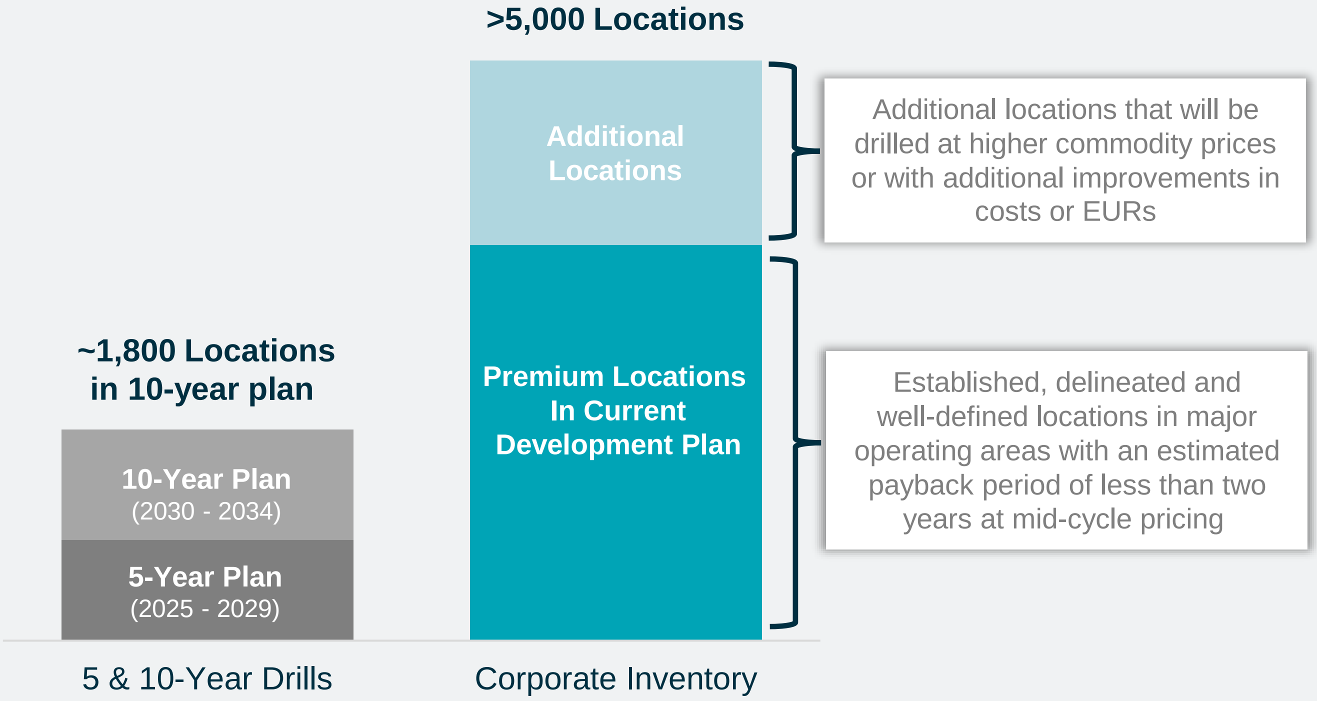


VRN has an investment-grade credit rating of BBB (low), with a Stable trend, issued by DBRS

Figures are approximates. Net debt to funds flow is based on Q4 annualized funds flow and is a specified financial measure – refer to Specified Financial Measures.
DBRS: Morningstar DBRS. YE 2029E assumes US$70/bbl WTI for 2025-2029, $2.25/mcf AECO for 2025, $3.00/mcf AECO for 2026-2029 and CAD/USD FX of $0.71 for 2025-2029.

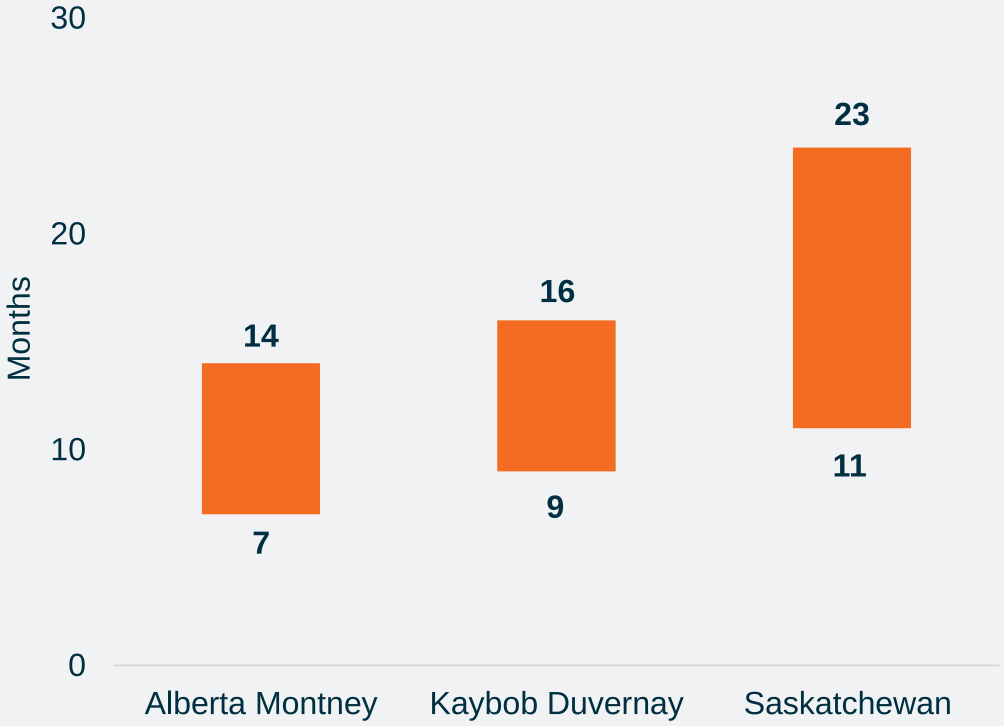
Highly Economic Long-Term Plan

Corporate Inventory vs 10-Year Plan



Economics of Premium Locations

(Well Payout – US$70 WTI & $3.00 AECO)



~20 years of premium inventory supports a highly economic development plan

Inventory locations presented above are net and include 1,486 booked proved plus probable (2P) locations, as derived from the Company's external reserves evaluation in accordance with NI 51-101 and the COGE Handbook.
Payouts are calculated from the initial on stream date. Economics of unbooked locations as part of premium inventory are based on booked type well expectations. EURs: estimated ultimate recoveries. Saskatchewan economics include Viewfield and Shaunavon.

How Veren Executes Its Strategy

Disciplined Per-Share Growth

- Balanced portfolio of long and short-cycle assets
- Disciplined capital allocation framework
- Enhancing value through culture of operational excellence

15% EXCF/share CAGR over 5-year plan (20% including share repurchases)

+

Significant Return of Capital

- Currently returning ~60% of excess cash flow
- High-netback assets generating significant excess cash flow
- Plan to grow base dividend over time, in-line with business

Plan to increase percentage of capital returned over time

+

Balance Sheet Strength

- Long-term leverage target of <1.0x at low commodity prices
- Track record of reducing debt and disciplined hedging strategy
- Investment-grade credit rating

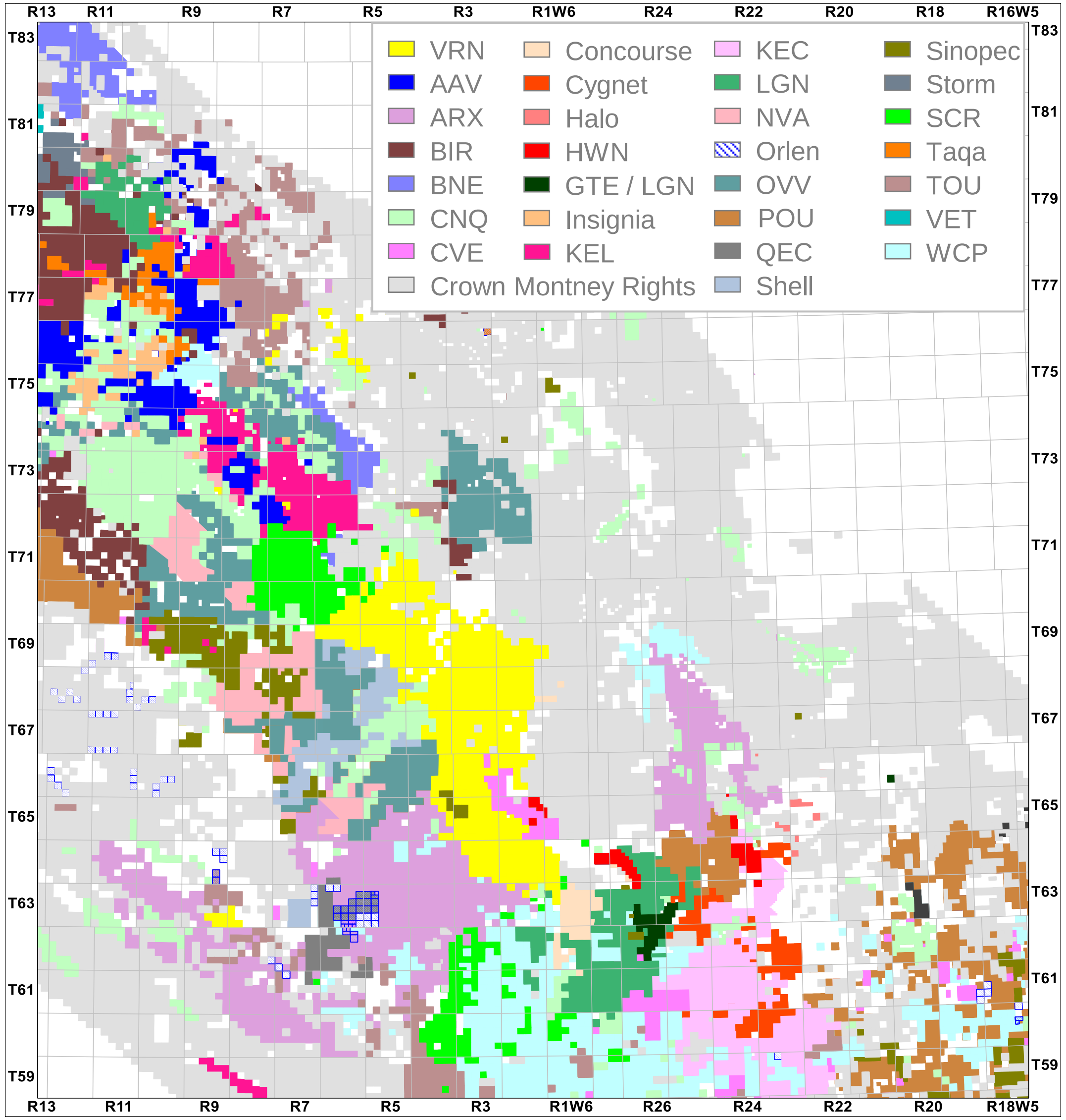
Expect to reduce net debt by ~70% over 5-year plan

Sustainable long-term returns driven by high-quality multi-basin portfolio and disciplined capital allocation

Net debt reduction and excess cash flow per share compound annual growth rate (CAGR) assume US$70/bbl WTI for 2025-2029, $2.25/mcf AECO for 2025, $3.00/mcf AECO for 2026-2029 and CAD/USD FX of $0.71 for 2025-2029.

Assets

Alberta Montney Asset Overview



Largest land position in the Volatile Oil fairway

~350,000 contiguous net acres in the Alberta Montney

Second largest producer in the Alberta Montney

2025E production of 92,000 boe/d (55% oil & liquids) and growing at 10% CAGR through 2029E

Deep premium inventory of >1,400 net locations

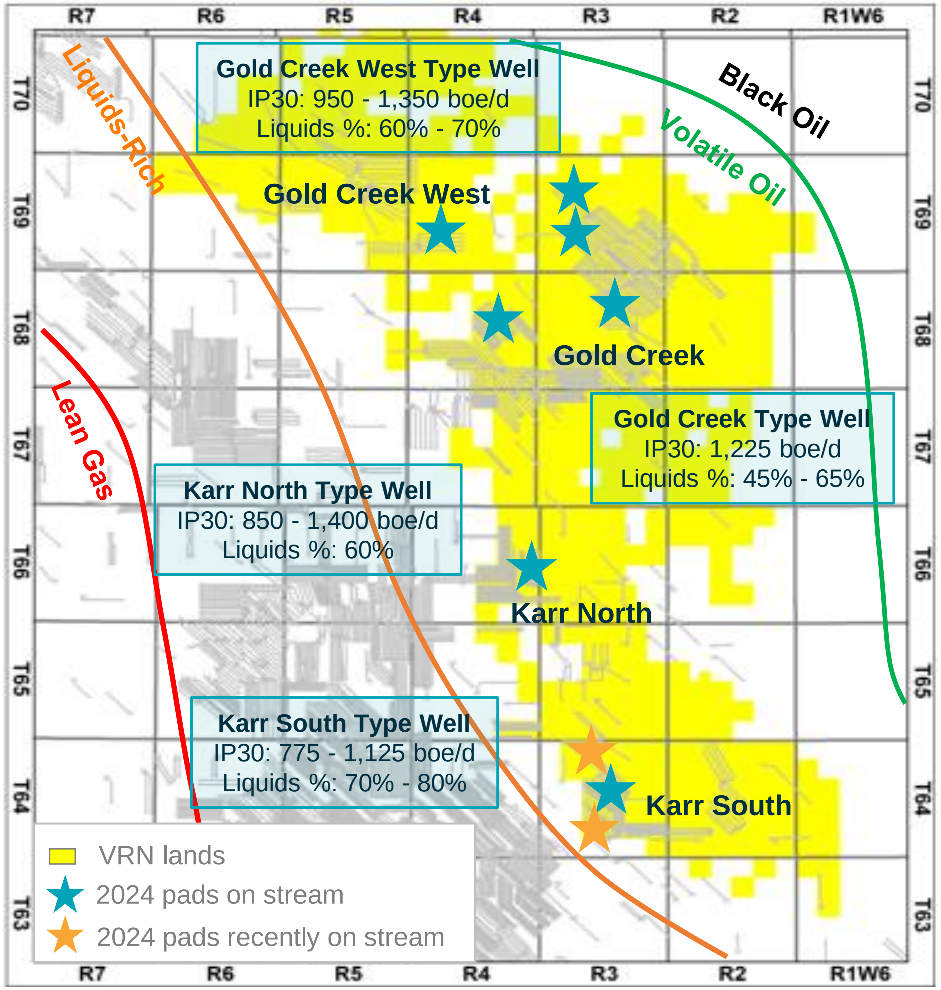
~70% of locations are currently unbooked

Strong netbacks generate significant excess cash

Represents ~45% of corporate excess cash flow within the five-year plan

Map source: Accumap and Enverus public data. All figures are approximates.
CAGR: compound annual growth rate. Assumes US$70/bbl WTI from 2025-2029, $2.25/mcf AECO for 2025, $3.00/mcf AECO for 2026-2029 and CAD/USD FX of $0.71 for 2025-2029.

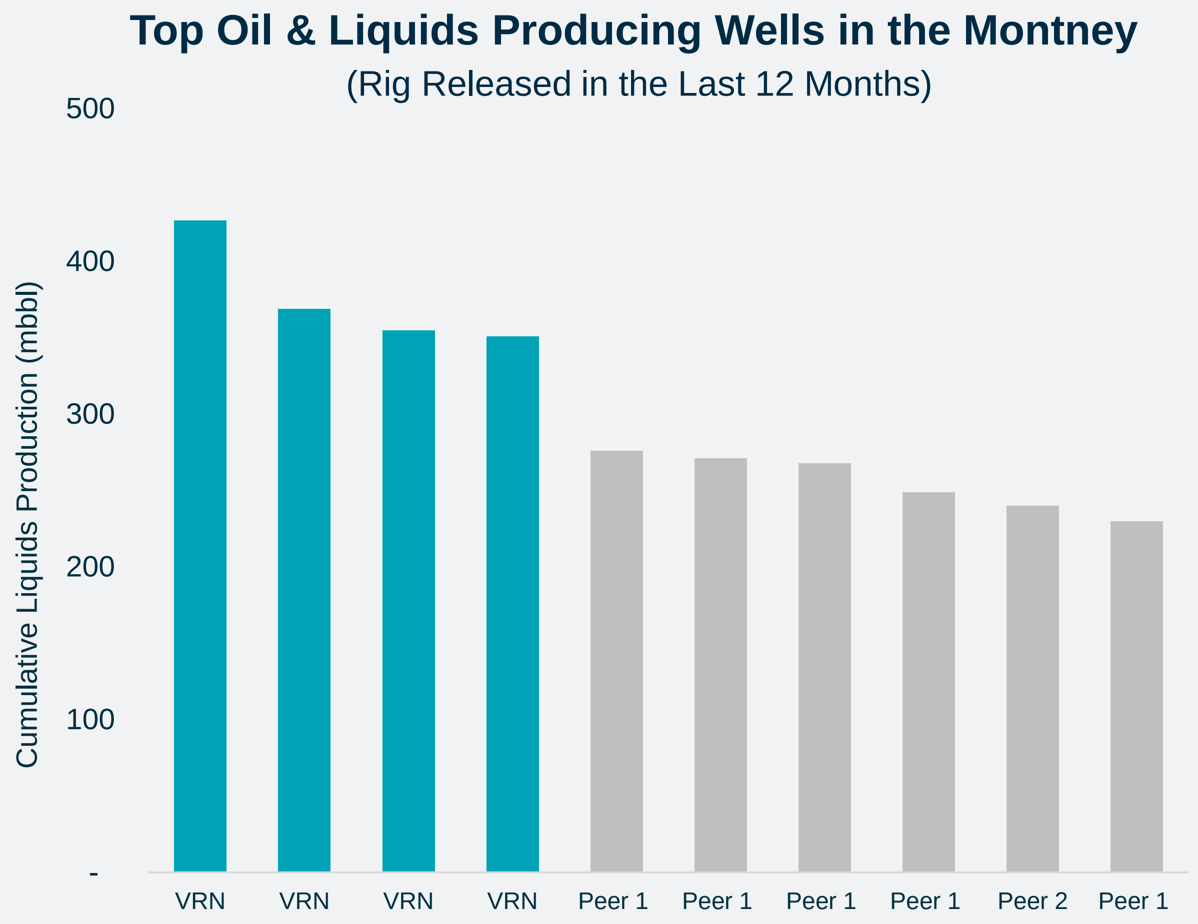
Alberta Montney Results & Development Plan

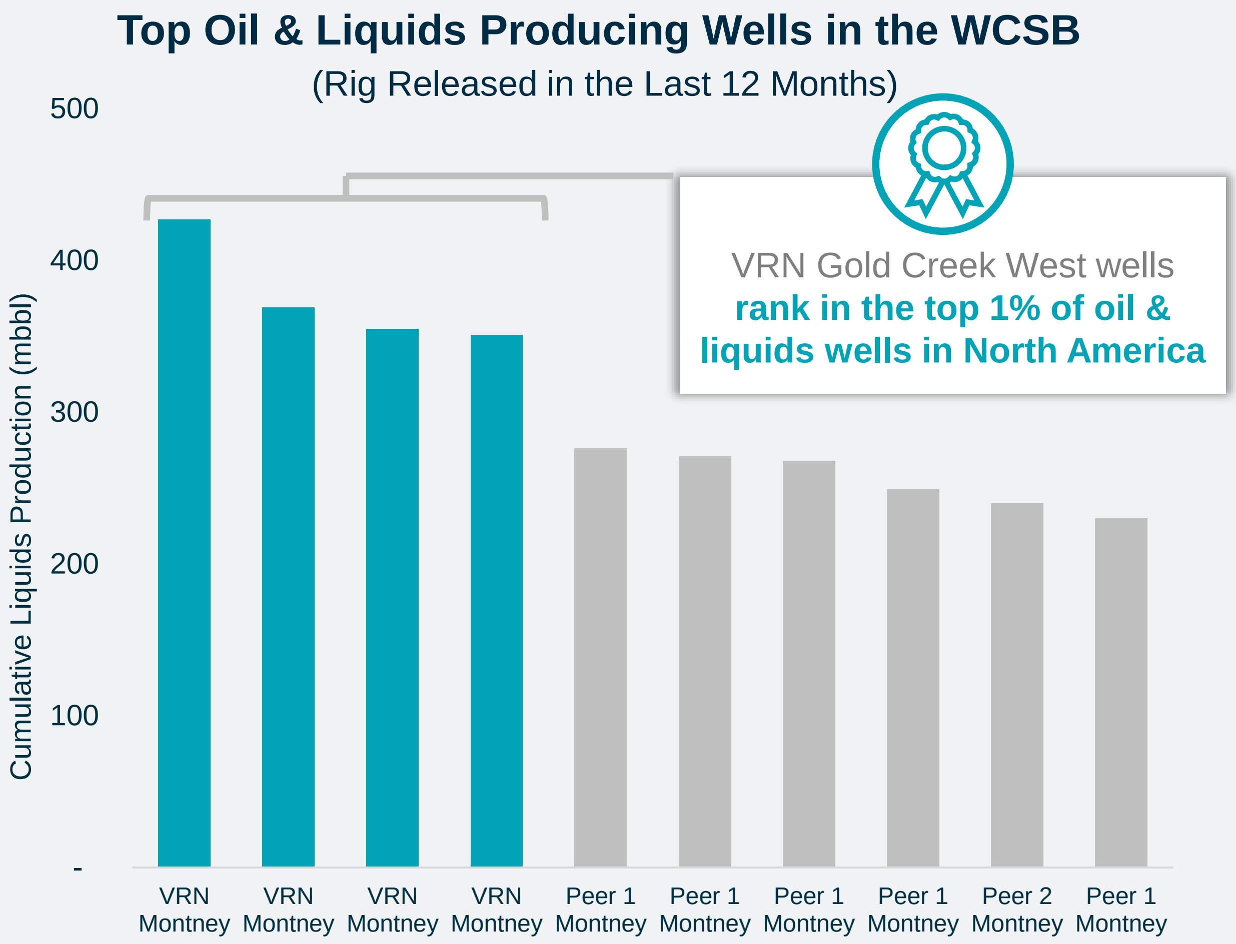


- **Focused on optimizing well design to enhance recovery of resource in place since entering the play in Q2 2023**
  - Returns and economics rank in the top quartile within portfolio
  - Opportunity for down-spacing and further step-out delineation
- **Targeting enhanced returns through strong operational execution**
  - Focused on optimizing infrastructure in the area which is expected to drive future operating cost savings, reduce downtime and increase production capacity
  - Refining drilling and completions design to enhance productivity and overall returns

High-quality position situated entirely in the Volatile Oil window

Recent Results Highlighting Returns & Scalability of Alberta Montney

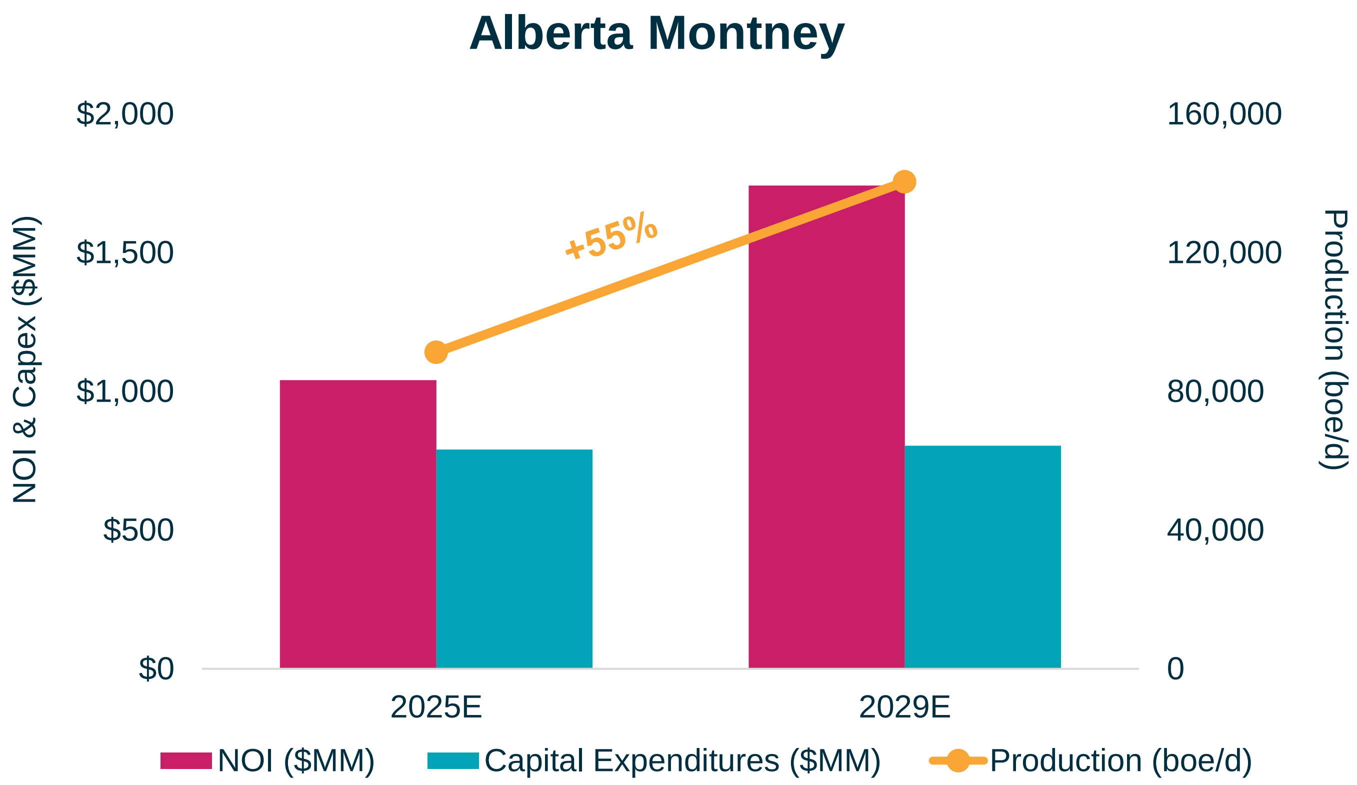


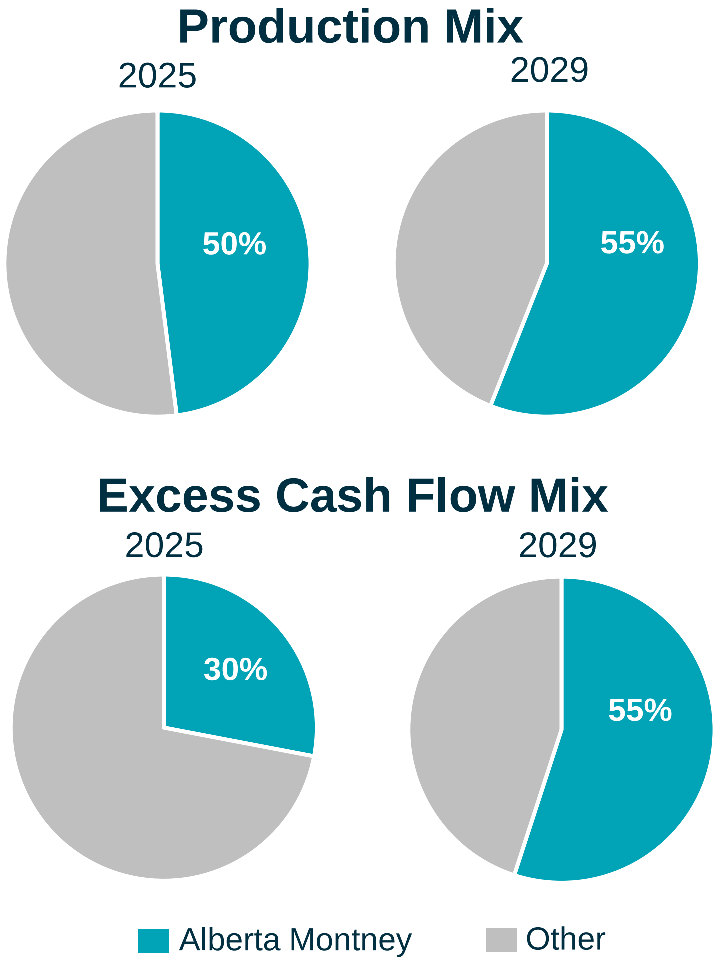


VRN wells consistently ranking among the top in the Montney and the WSCB

Source: RBC Capital Markets. WCSB: Western Canadian Sedimentary Basin. Data based on the 12 months ending December 2024.
Gold Creek West wells rank in the top 1% of all oil and liquids wells brought on stream in North America over the last three years based on an initial production rate of 180 days (source: HTM Energy Research).

Alberta Montney 5-Year Outlook (2025 – 2029)

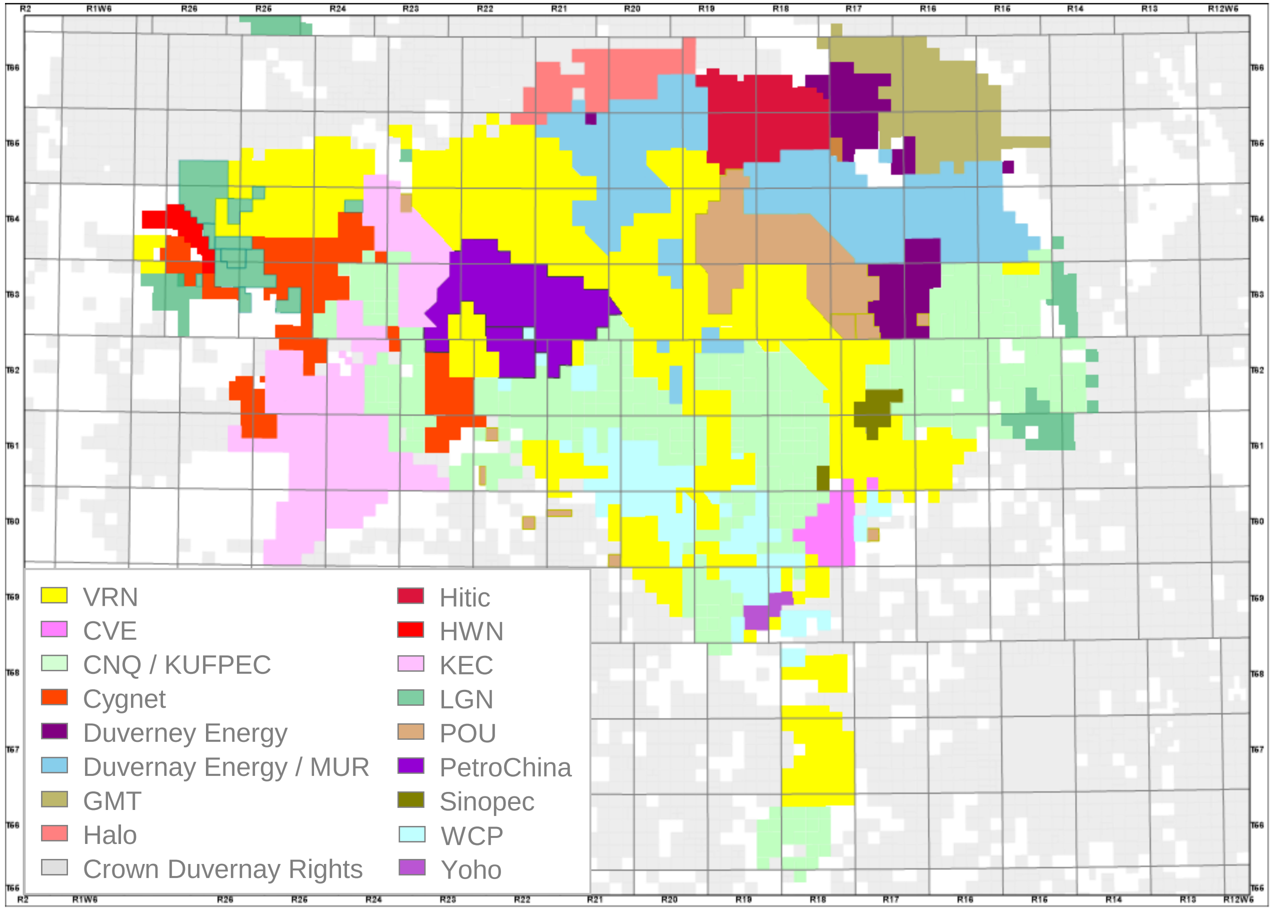




Production CAGR of ~10% through 2029 in addition to generating significant excess cash flow growth

All figures are approximates. Asset level excess cash flow is net operating income less capex. Assumes US$70/bbl WTI for 2025-2029, $2.25/mcf AECO for 2025, $3.00/mcf AECO for 2026-2029 and CAD/USD FX of $0.71 for 2025-2029.

Kaybob Duvernay Asset Overview



Largest land position in the Kaybob Duvernay

~410,000 net acres primarily in oil and liquids-rich windows

Largest producer in the Kaybob Duvernay

2025E production of 60,000 boe/d (60% condensate & liquids) and growing at >5% CAGR through 2029E

Deep premium inventory of ~500 net locations

~60% of locations are currently unbooked

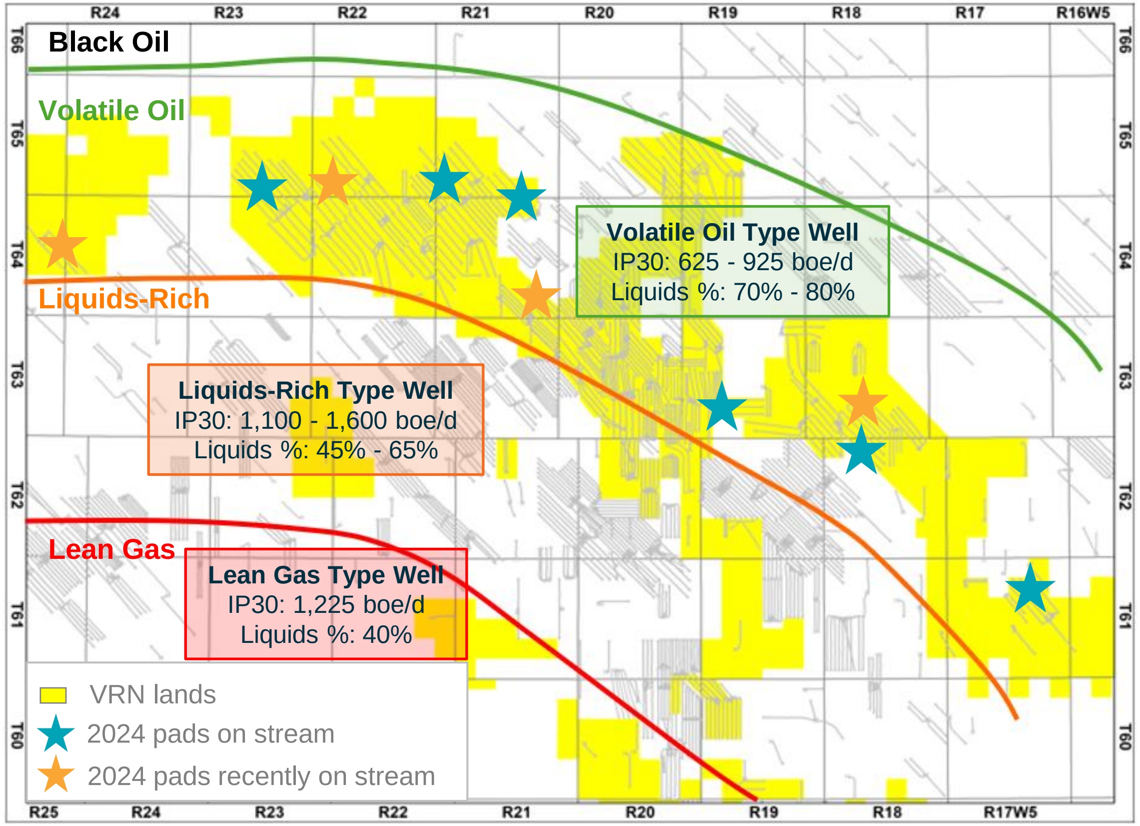
Strong netbacks generate significant excess cash

Represents ~35% of corporate excess cash flow within the five-year plan

Map source: Accumap and Enverus public data. All figures are approximates.
CAGR: compound annual growth rate. Assumes US$70/bbl WTI from 2025-2029, $2.25/mcf AECO for 2025, $3.00/mcf AECO for 2026-2029 and CAD/USD FX of $0.71 for 2025-2029.

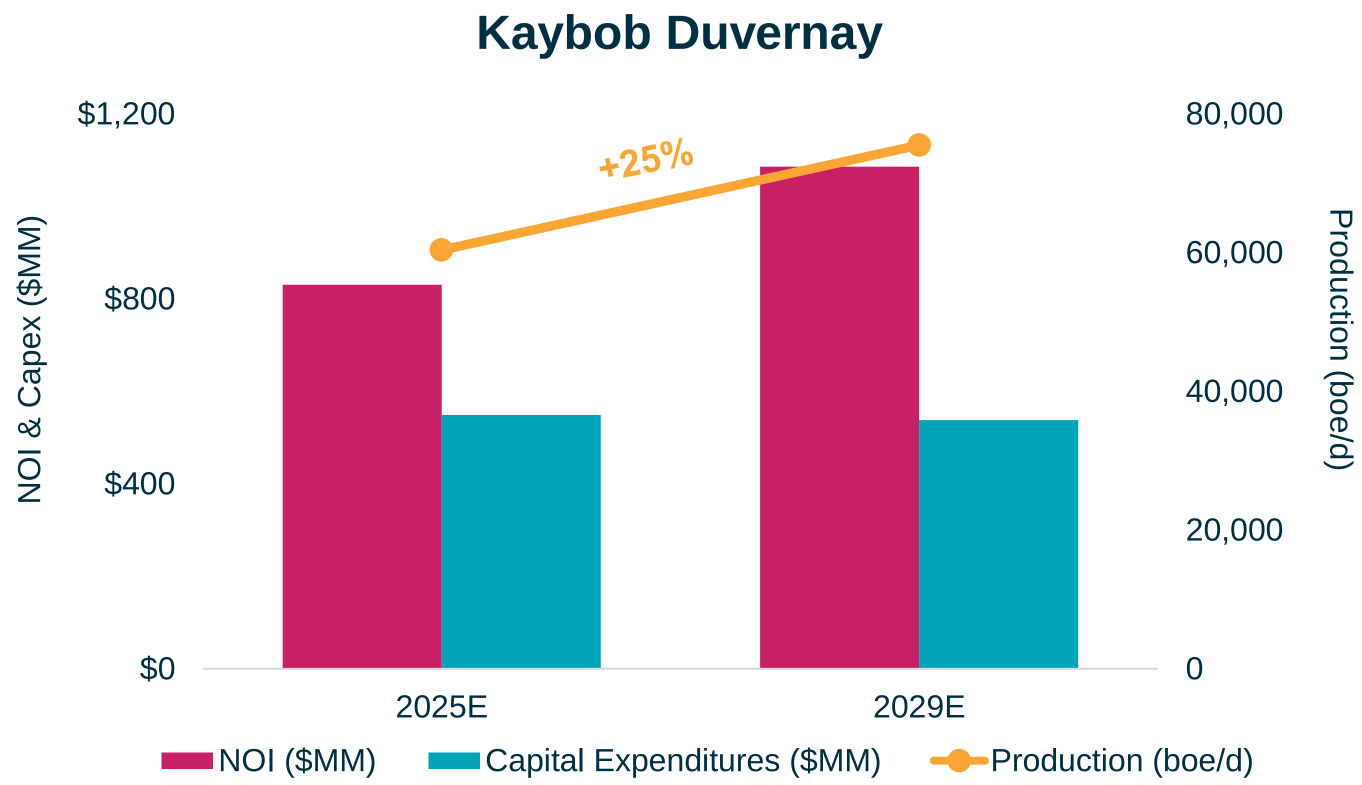
Kaybob Duvernay Results & Development Plan

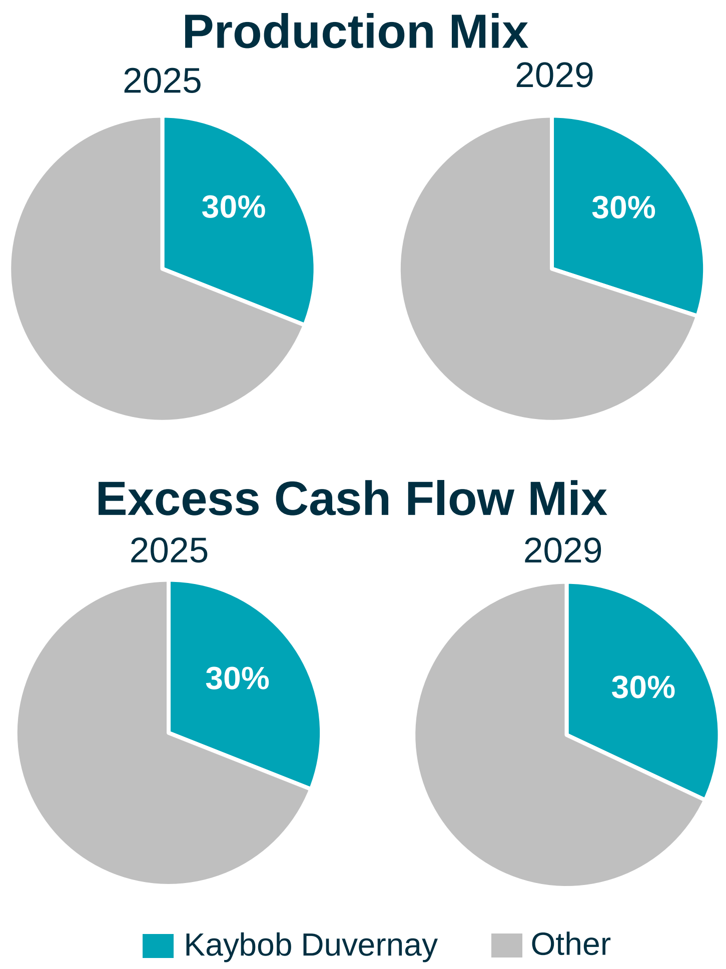
- **Track record of cost efficiencies and improving productivity**
  - Initial entry into the play in Q2 2021
  - Optimized drilling and completion approach resulting in improved results
  - Quickly reduced drilling days upon entering the play given experience in large multi-well pad programs
- **Focused on delivering consistent results and enhancing returns**
  - Drilling longer lateral wells to improve efficiencies and delineating across the land base
  - Opportunity for down-spacing and further step-out delineation



Delivering consistent results, high-returns and combination of growth and excess cash flow generation

Kaybob Duvernay 5-Year Outlook (2025 – 2029)





Production CAGR of >5% through 2029 in addition to generating significant excess cash flow growth

All figures are approximates. Asset level excess cash flow is net operating income less capex. Assumes US$70/bbl WTI for 2025-2029, $2.25/mcf AECO for 2025, $3.00/mcf AECO for 2026-2029 and CAD/USD FX of $0.71 for 2025-2029.

Saskatchewan: Decline Mitigation & OHML

- High-netback oil & liquids assets **generating significant excess cash flow**

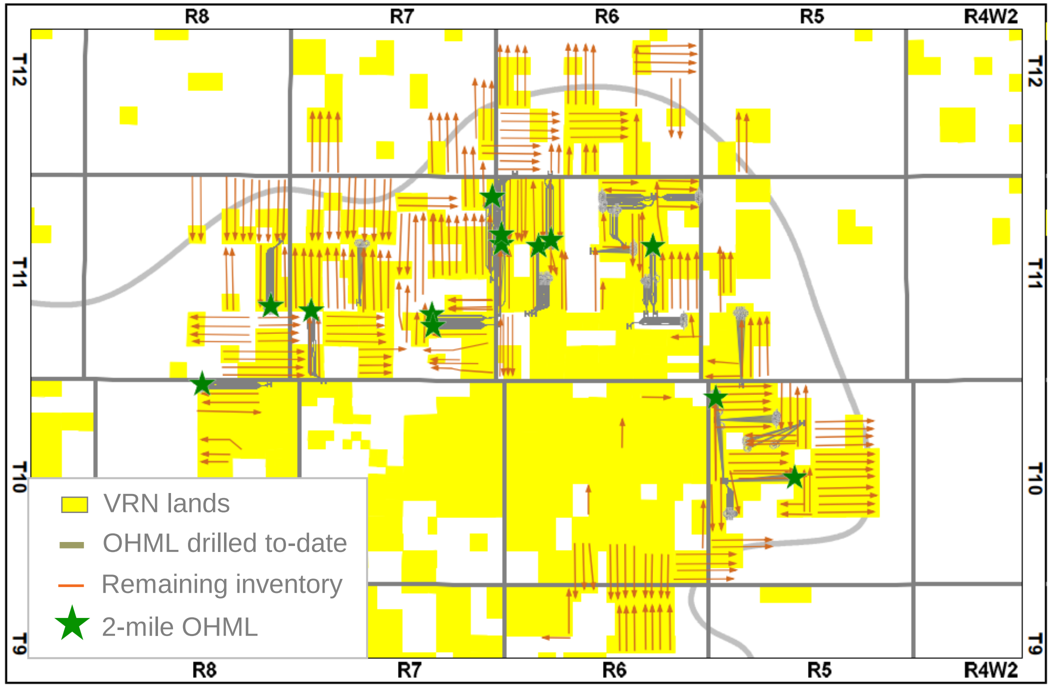
Decline Mitigation

- **Low decline rate (~15%)** as a result of commitment to decline mitigation projects, including waterflood and polymer floods
  - Low F&D costs, attractive long-term economics and enhanced EURs

Open-Hole Multi-Laterals (OHML)

- **Improving returns** by applying OHML drilling in Viewfield
  - Enhances EURs, economics and capital efficiencies
    - Economics further improved by royalty incentive announced by the Government of Saskatchewan in 2024
  - ~135 net internally identified OHML locations which are ~80% unbooked at YE 2024 allowing for reserves growth

Viewfield OHML

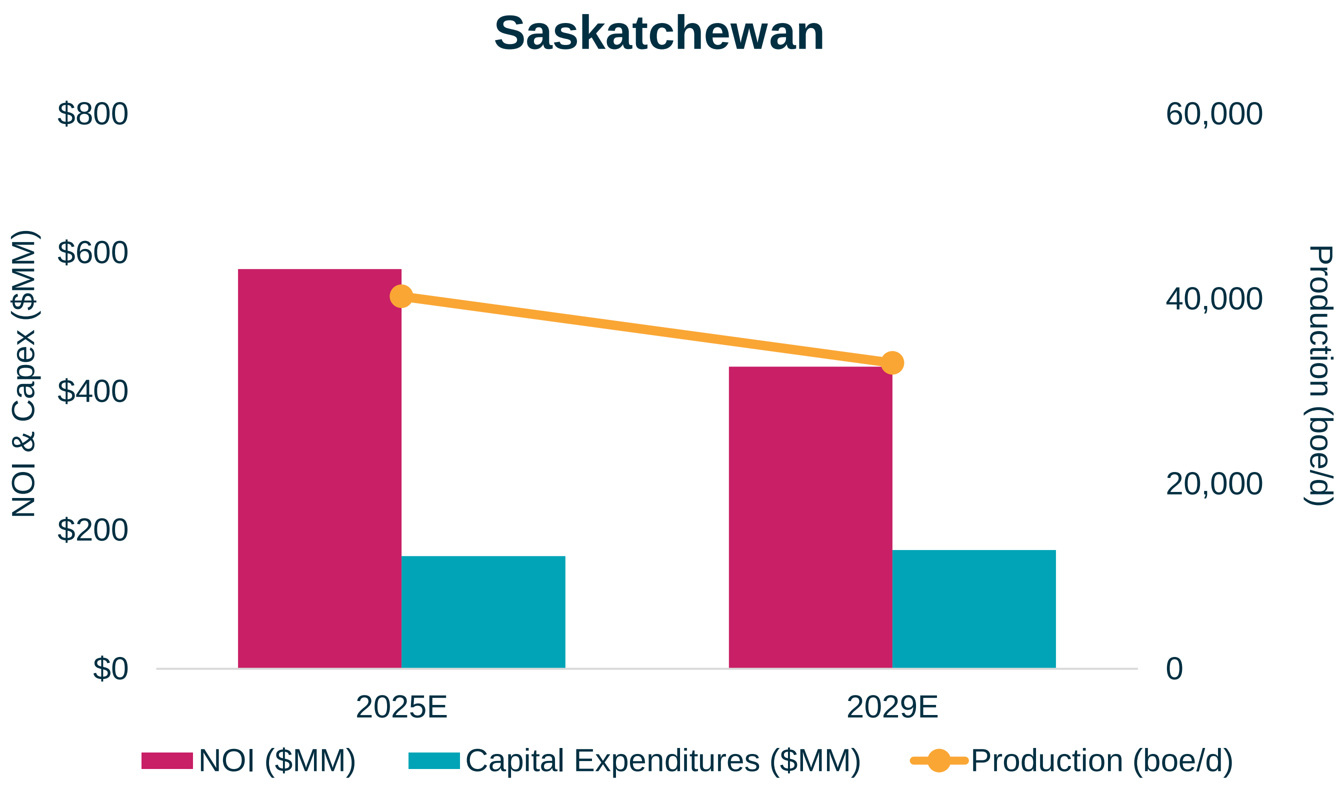


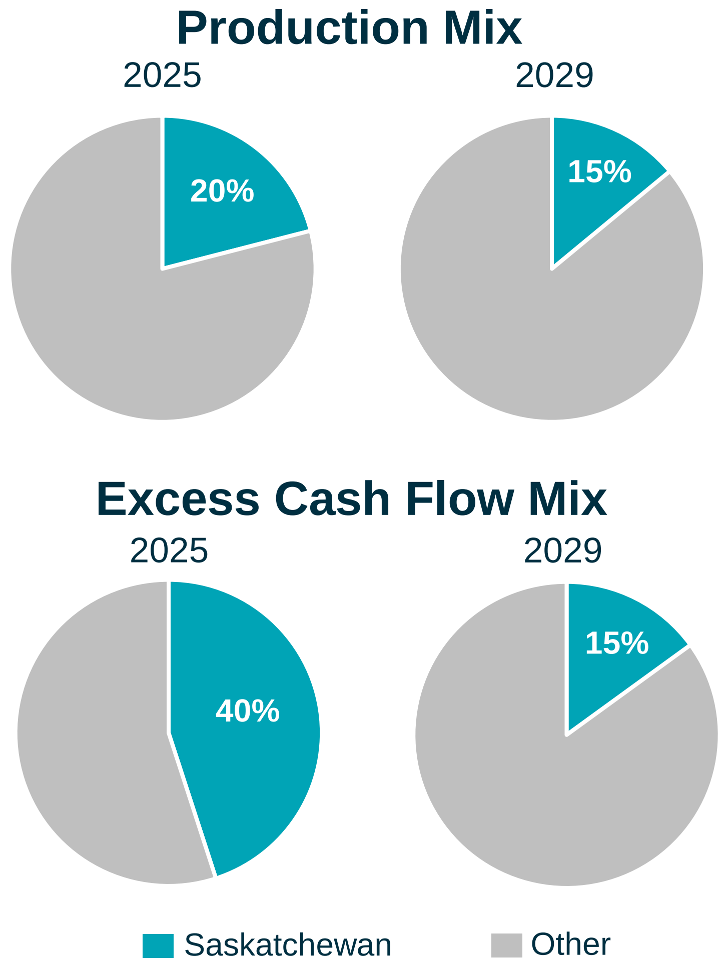
Well Type	Wells Per Two Sections	Capital ($MM)	NPV10 ($MM)	IRR%	Payout (months)	EUR (Mbbl)
Frac'd	8	14	6	41%	23	400
OHML	4	11	12	96%	11	560

Low decline, stable production and significant excess cash flow generation

F&D: finding and development. EUR: estimated ultimate recoveries. Economics assume US$70/bbl WTI and $3.00/mcf AECO and reflect new multi-lateral well incentive in Saskatchewan.
Frac'd and OHML economics based on booked proved plus probable (2P) type wells as assigned by independent reserves evaluator McDaniel as at December 31, 2024.

Saskatchewan 5-Year Outlook (2025 – 2029)





Strong excess cash flow generation bolstered by enhanced oil recovery and new technology implementation

All figures are approximates. Asset level excess cash flow is net operating income less capex. Assumes US$70/bbl WTI for 2025-2029, $2.25/mcf AECO for 2025, $3.00/mcf AECO for 2026-2029 and CAD/USD FX of $0.71 for 2025-2029.

Appendix

Capital Markets Summary & Guidance

Capital Markets Summary VRN (TSX and NYSE)	
Share Price (Feb. 19, 2025)	C$7.59 / US$5.34
Shares Outstanding	612 million
Avg. Daily Trading Volume	19.4 million
Annual Dividend Yield	6.1%
Market Capitalization	$4.6 billion
Net Debt	$2.5 billion
Enterprise Value	$7.1 billion

Dividend yield based on quarterly base dividend of $0.115/share. Net debt as at December 31, 2024. Share price and avg. daily trading volume source: Bloomberg. Avg. daily trading volume based on CDN and US volumes from trailing 3-months as of February 19, 2025.

2025 Guidance	
Annual Avg. Production (boe/d)[1]	188,000 - 196,000
Development Capital Expenditures[2] [3]	$1,475 - $1,575
Other Information Annual Operating Expenses ($/boe) Royalties	 $12.75 - $13.75 10.75% - 11.75%

1) The total annual average production for 2025 (boe/d) is comprised of approximately 65% Oil, Condensate & NGLs and 35% Natural Gas
2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section.
3) Excludes capitalized administration of approximately $40 million, in addition to land expenditures and net property acquisitions and dispositions. Development capital expenditures spend for 2025 is allocated on an approximate basis as follows: 85% drilling & development and 15% facilities & seismic

Return of Capital Outlook	
Quarterly Base Dividend	$0.115/share
Total Return of Capital (Dividends & Share Repurchases)	60% (% of Excess Cash Flow)

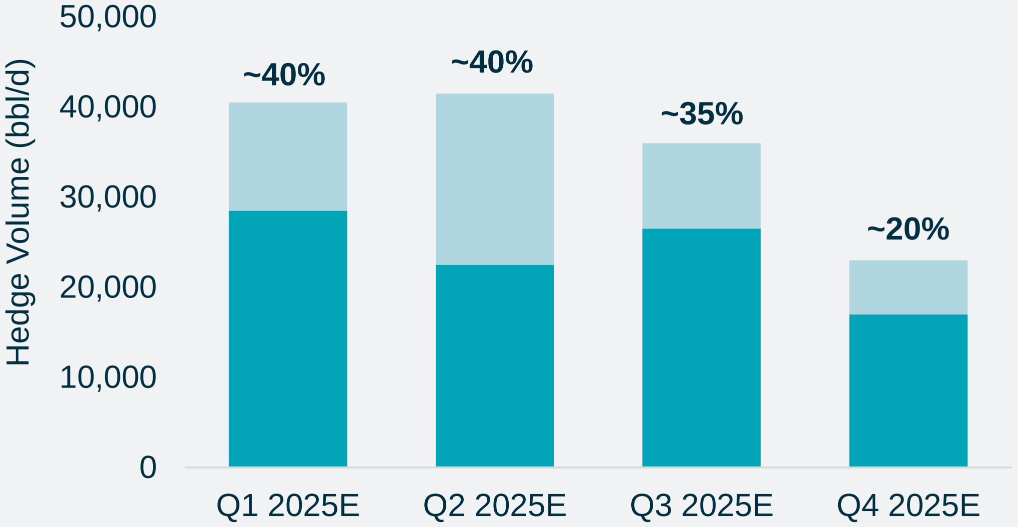
Total return of capital is based on a framework that targets to return to shareholders 60% of excess cash flow on an annual basis

2025 Funds Flow Sensitivities	
US$1/bbl Change in WTI	~$35 million
$0.25/mcf Change in Benchmark Gas Prices	~$20 million
$0.01 Change in CAD/USD FX	~$30 million

Hedging Summary

Oil & Liquids Hedging

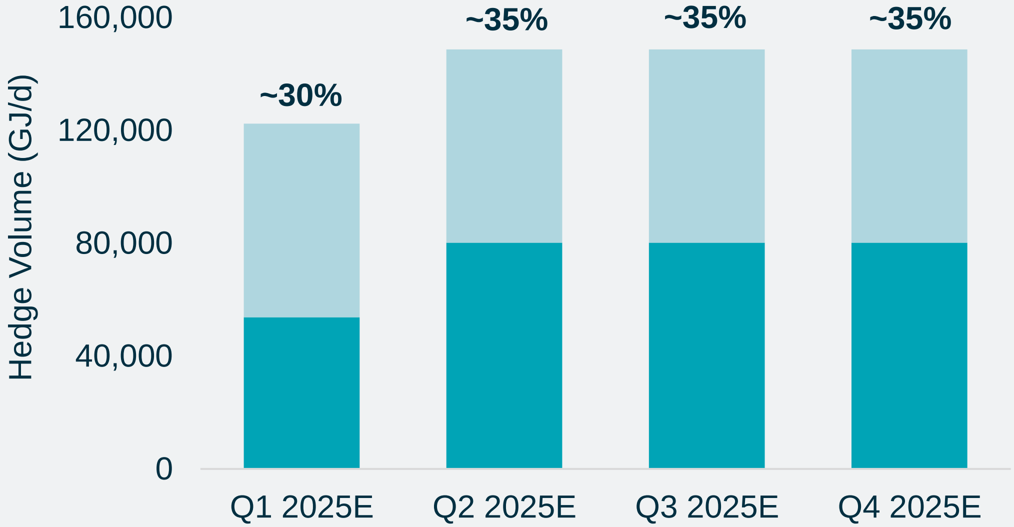
Oil & liquids hedges extend through 2025



	Q1 2025E	Q2 2025E	Q3 2025E	Q4 2025E
Swap (C$)	$101.04	$101.30	$98.05	$96.56
Collar Floor (C$)	$95.78	$96.32	$95.40	$95.38
Collar Ceiling (C$)	$105.78	$106.32	$105.40	$105.38

Gas Hedging

Gas hedges extend through 2026



	Q1 2025E	Q2 2025E	Q3 2025E	Q4 2025E
Swap (C$)	$4.64	$4.68	$4.67	$4.65
Collar Floor (C$)	$4.50	$4.45	$4.44	$4.42
Collar Ceiling (C$)	$5.30	$5.25	$5.23	$5.20

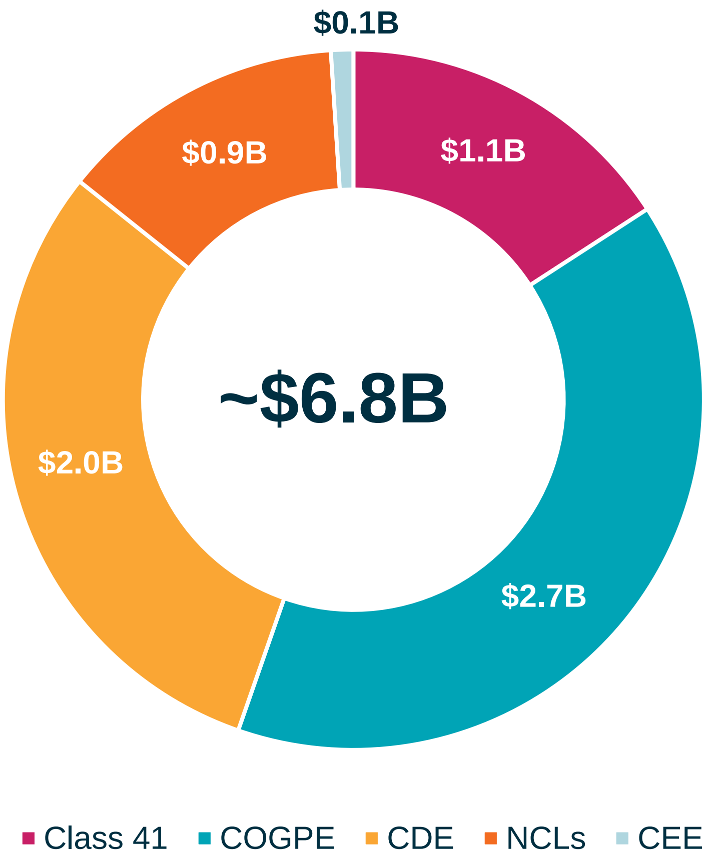
Collars Swaps

Disciplined hedging program provides downside price protection and protects the balance sheet

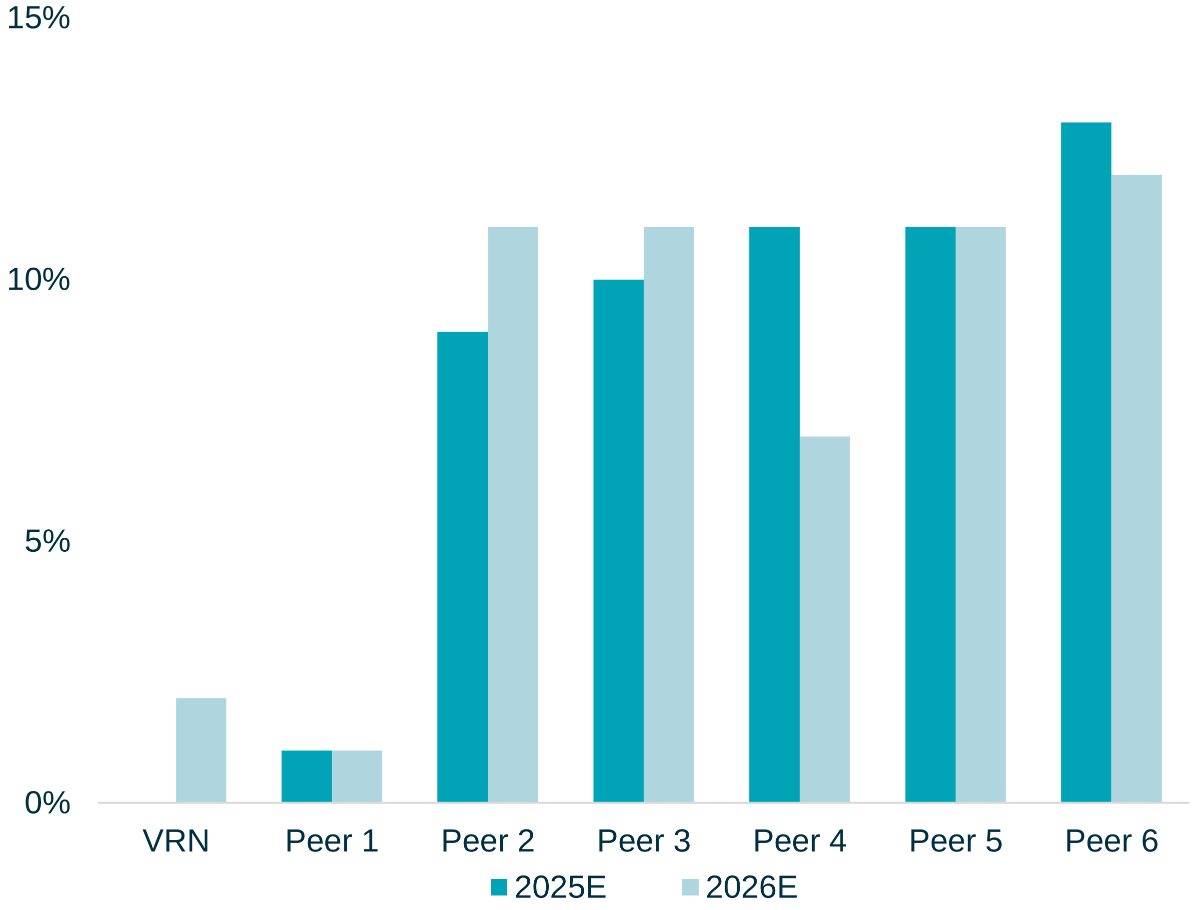
Hedged volumes as at February 19, 2025. Hedged production is a percentage of volume net of royalty interest. Oil hedges are fixed WTI pricing and gas hedges are fixed AECO and NYMEX pricing.

Significant Tax Pools Enhance Excess Cash Flow

Canadian Tax Pools



Cash Tax as % of Before Tax Cash Flow



CDN Peer List: ARX, BTE, NVA, TOU, VET, WCP. Canadian tax pools as of December 31, 2024.
Cash tax source: Peters & Co. Equity Research (February 18, 2025; 2025 strip of US$70.96/bbl WTI & CAD/USD FX of $0.71 and 2026 strip of US$66.98/bbl WTI & CAD/USD FX of $0.72).

Strong Market Access

Liquids (65% of Production)

Alberta (Kaybob Duvernay & Montney)

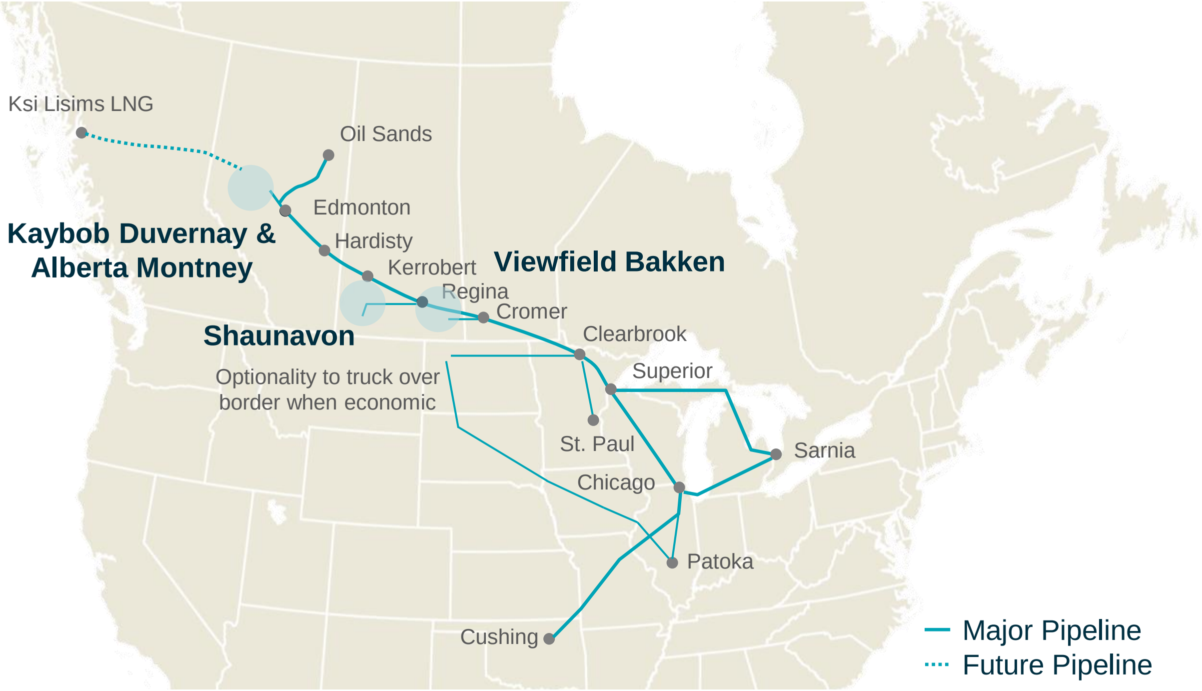
- MSW and C5 generally trade near WTI, with C5 benefitting from a strong expected demand outlook
- C5 has optionality to be sold as is for oil sands or as light oil

Saskatchewan (Viewfield Bakken & Shaunavon)

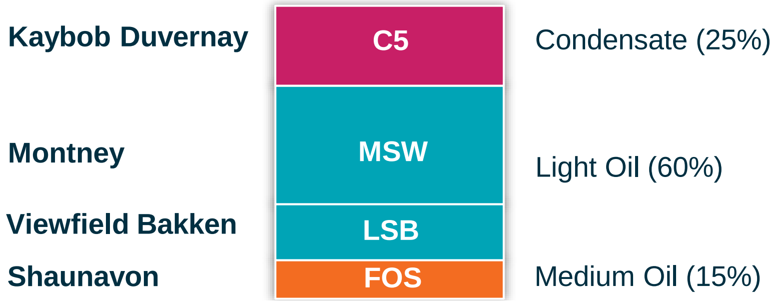
- LSB (SE Sask.) generally trades at a slight discount to WTI and FOS (SW Sask.) receives premium to WCS
- Below major apportionment points and close to U.S. border providing additional marketing optionality

Gas (35% of Production)

- Receives premium pricing to AECO, with exposure to NYMEX, Chicago, Dawn and Malin & Stanfield pricing
- Exposure to international natural gas pricing through future Ksi Lisims LNG project

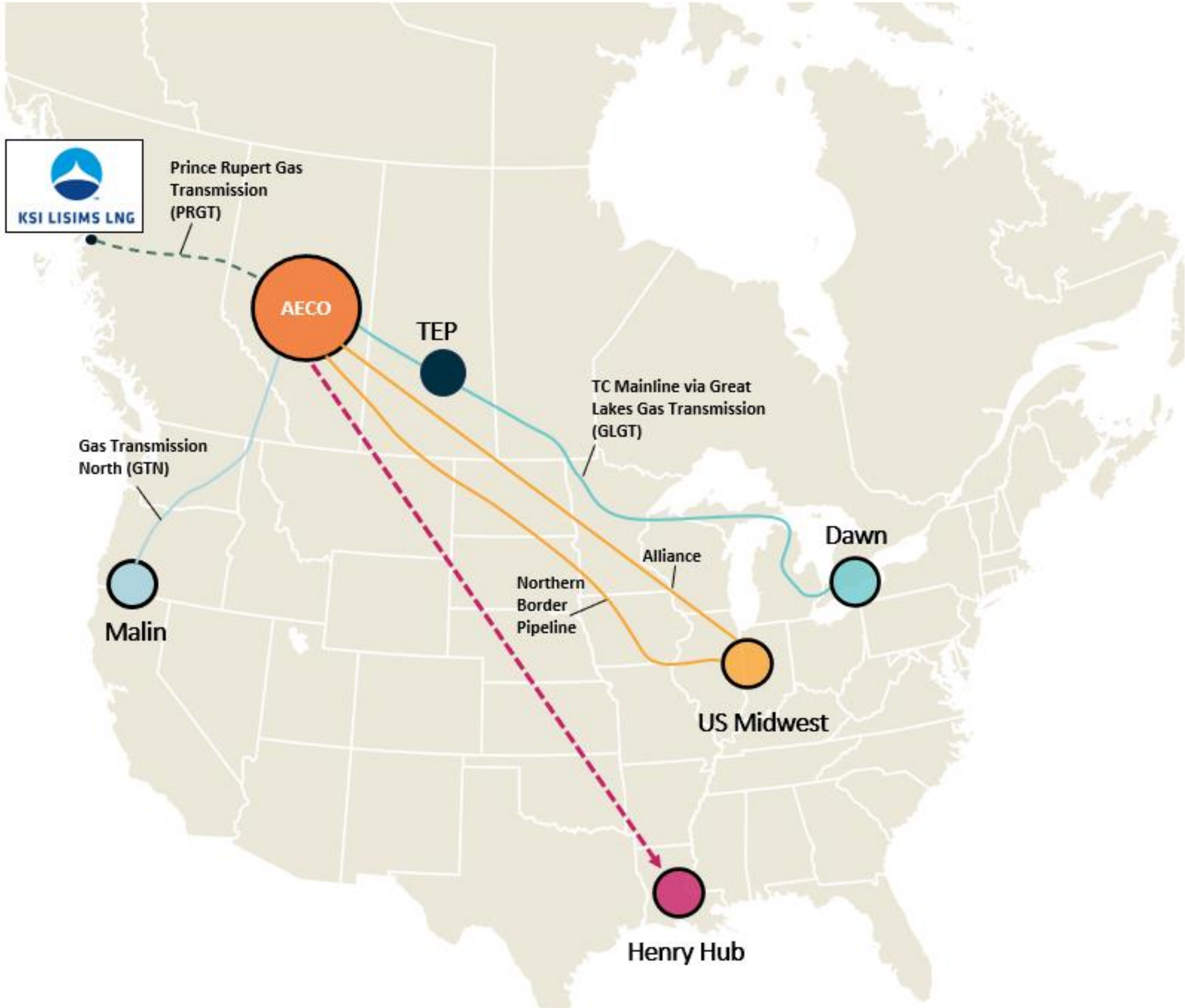


2025E Oil & Condensate Production Breakdown by Stream

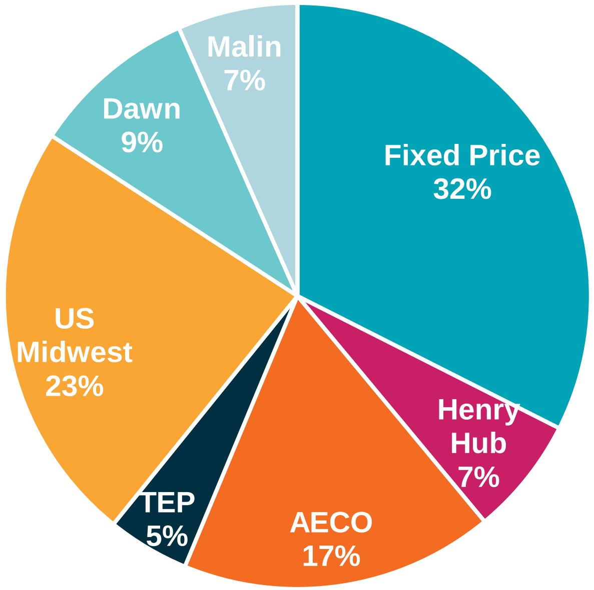


WCS: Western Canadian select. FOS: Fosterton, LSB: Light Sour Blend, C5: condensate. MSW: Mixed Sweet Blend. Percentages are based on 2025 production.

Majority of Natural Gas Diversified Away from Alberta



Diversification Through 2026



TEP – Saskatchewan hub trades at a premium to AECO – current contract year premium ~$0.40/GJ. Gas diversification is from March 2025 through YE 2026.

Portfolio of High-Netback Assets

Metric (US$70 WTI)	Alberta Montney	Kaybob Duvernay	Saskatchewan
Average Production (boe/d)	92,000	60,000	40,000
% Liquids	55%	60%	90%
Royalty (%)	12%	11%	10%
Operating Expenses ($/boe)	$11.00	$8.00	$27.00
Operating Netback ($/boe)	$32.00	$38.00	$39.00
Base Decline Rate	Mid-30%	Low-30%	~15%
Premium Locations (Net)	>1,400	~500	~1,500

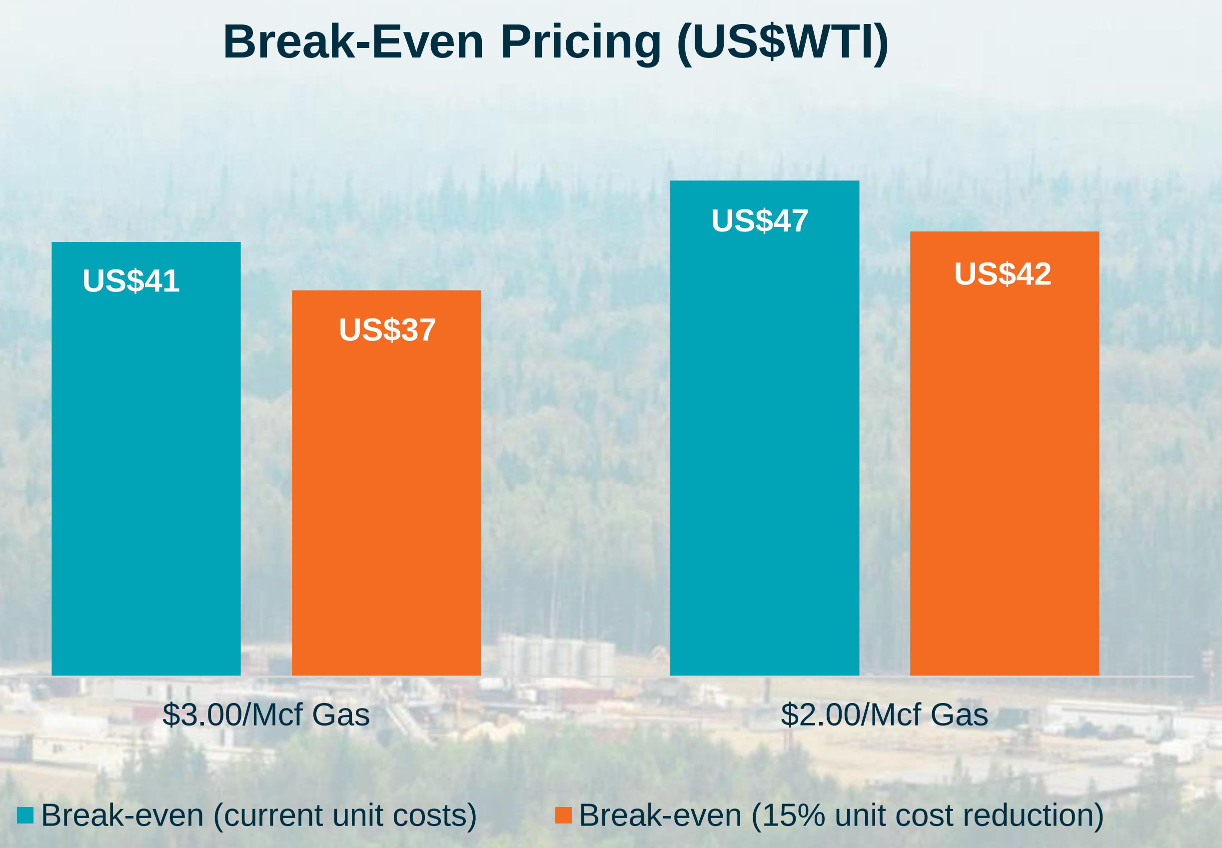
All figures are approximates and are based on 2025 guidance, US$70/bbl WTI, $2.25/mcf AECO and CAD/USD FX of $0.71. Operating expenses and operating netback rounded to the nearest dollar. Base decline rate is dependent on pad timing. Operating netback is a specified financial measure - refer to the Specified Financial Measures section. Inventory based on YE 2024 locations.

Core Area Economics

					US$70 WTI & $3.00 AECO		
Area	IP30 boe/d (Liquids %)	EUR Mboe (Liquids %)	Net Locations	Cost Per Well ($MM)	NPV10% ($MM)	IRR%	Payout (Months)
Alberta Montney (Volatile Oil)							
Gold Creek West	950 - 1,350 (60% - 70%)	700 - 900 (55%)	310	$9.5	$6.0 - $11.0	50% - 120%	7 - 14
Gold Creek	1,225 (45% - 65%)	1,050 (40% - 50%)	560	$9.5	$7.0 - $11.0	55% - 100%	8 - 14
Karr North	850 - 1,400 (60%)	750 - 1,225 (50%)	425	$10.0	$6.0 - $13.5	45% - 115%	8 - 17
Karr South	775 - 1,125 (70% - 80%)	700 - 900 (55% - 70%)	135	$10.5	$8.0 - $10.5	55% - 90%	10 - 14
Kaybob Duvernay							
Volatile Oil	625 - 925 (70% - 80%)	650 - 1,075 (60% - 75%)	235	$11.5	$9.0 - $16.0	60% - 85%	9 - 14
Liquids-Rich	1,100 - 1,600 (45% - 65%)	900 - 1,800 (45% - 55%)	125	$11.5	$10.0 - $18.0	75% - 110%	9 - 10
Lean Gas	1,225 (40%)	1,725 (35%)	160	$11.5	$11.0	55%	16
Viewfield Bakken	140 - 240 (>90%)	75 - 140 (>90%)	635	$1.8 - $2.8	$0.7 - $3.0	40% - 100%	11 - 23
Shaunavon	110 - 140 (>90%)	60 - 100 (>85%)	650	$1.9	$0.5 - $1.4	35% - 85%	12 - 22
SE Conventional	55 - 140 (>90%)	70 - 90 (>90%)	185	$1.6	$0.9 - $1.9	35% - 150%	13 - 30

All figures are approximates. See advisories. Estimated ultimate recoveries (EURs) based on an average of booked proved plus probable (2P) type well assigned by independent reserves evaluator McDaniel as at December 31, 2024.
Payouts are calculated from the initial on stream date. Alberta Montney assumes 3,000m lateral length and Kaybob Duvernay assumes 3,500m lateral length.

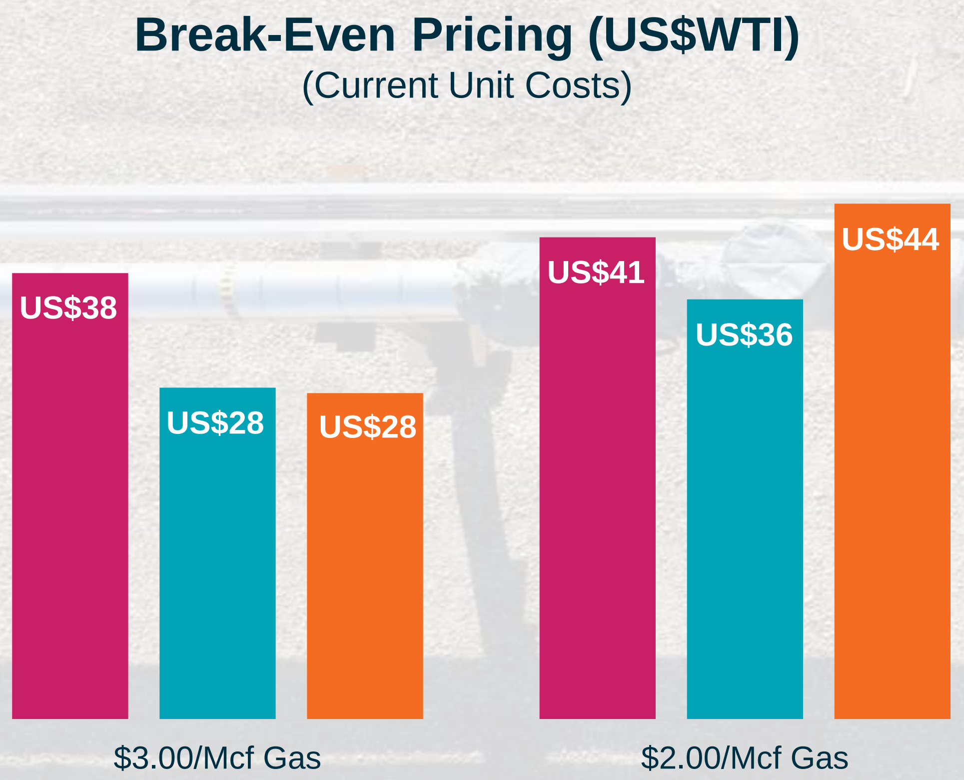
Alberta Montney Break-Even Economics & Sensitivity to Gas Prices

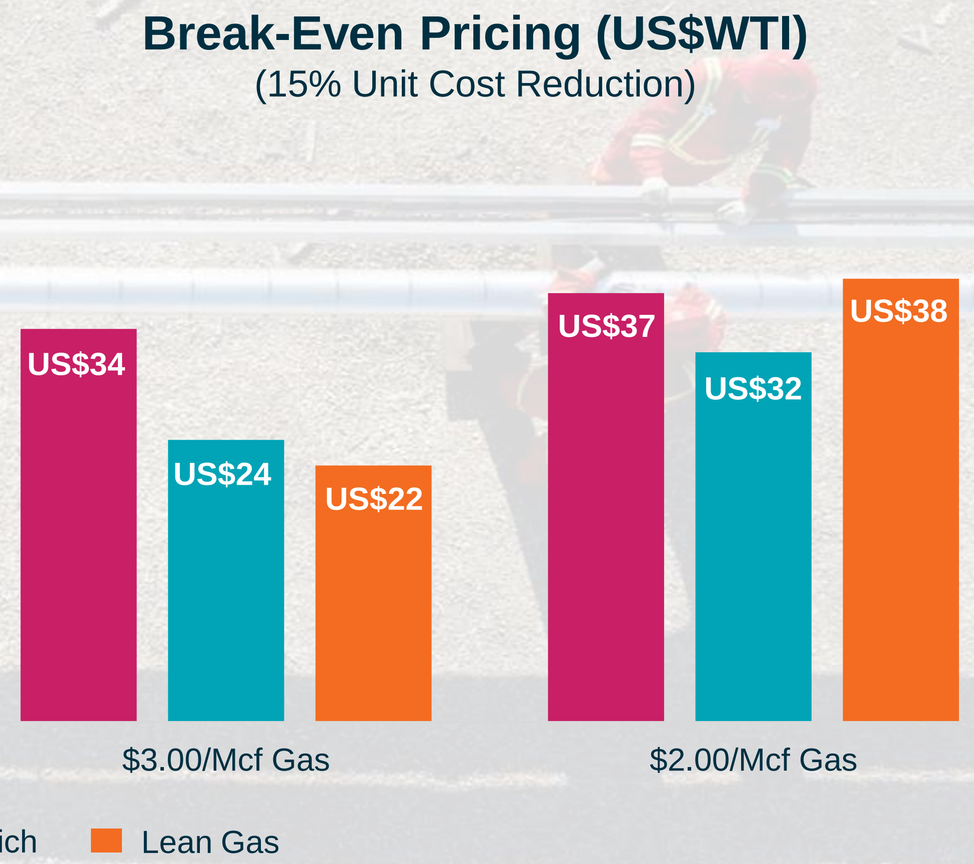


Alberta Montney inventory provides attractive economics given location within the Volatile Oil window

All figures are approximates. Break-even is based on BT NPV10%. Economics based on proved plus probable (2P) booked type wells assigned by independent reserves evaluator McDaniel as at December 31, 2024. Gas price sensitivity (AECO).

Kaybob Duvernay Break-Even Economics & Sensitivity to Gas Prices





Attractive economics with ~70% of inventory situated in Volatile Oil and Liquids-Rich windows

All figures are approximates. Break-even is based on BT NPV10%. Economics based on proved plus probable (2P) booked type wells assigned by independent reserves evaluator McDaniel as at December 31, 2024. Gas price sensitivity (AECO).

Strategy Focused on Delivering Long-Term Value

Deliver Long-Term Value

Strategy Support

Process driven with component strategies in place

Finance	People
Digital	Portfolio
Communications	Stakeholders & ESG

Foundation Of Our Strategy

Purpose led company with core convictions driving

Why we do what we do
What we believe in
How we behave

Strategy

Our **actions**, **goals and vision** are **guided by** our **corporate strategy**

*“**Deliver lasting market-leading value to our stakeholders** as a **trusted, ethical, and environmentally responsible** source for energy. We will **maintain a resilient, balanced and sustainable portfolio**, and apply our agile, diverse, learning mindset to optimize all aspects of our business”*

Returns Based Capital Allocation Framework & Excess Cash Flow Priorities

Asset Level

Base Plan
- Risk Adjusted Returns and Value Added (Well & Project Level)

Long-Term
- Decline Mitigation
- Step-out Drilling
- Land Expiries
- Other Projects

Environmental
- ARO
- Emissions Reduction
- Asset Integrity
- Spill Prevention

Corporate Level

Funds Flow
(Maximize with a cost discipline)

↓

Maintenance Capital
(Total spending in context of balance sheet and returns)

↓

Balance Sheet / Base Dividend

↓

Follow-on decisions compete for capital based on expected returns and long-term corporate objectives

Additional Debt Reduction • **Additional Return of Capital** • **Organic Growth** • **M&A / Enhance Portfolio** • **Long-Term & Other**

ARO: Asset Retirement Obligations. Funds Flow is Adjusted Funds Flow.

Board of Directors

Barbara Munroe
Chair of the Board
>30 years of legal experience and industry diversification. Former EVP with WestJet Airlines.

Craig Bryksa 3
President & Chief Executive Officer
>20 years of oil and gas experience, including >15 years with the company in several senior management roles.

Corey Bieber 1 2
>35 years of financial and management expertise in energy. Former CFO of Canadian Natural Resources.

James E. Craddock 2 4 5
>30 years of upstream E&P experience. Former Chairman and CEO of Rosetta Resources.

John P. Dielwart 3 5
>40 years of experience in the oil and gas sector. Founding member of ARC Resources.

Mike Jackson 1 2
>30 years in corporate and investment banking holding several senior management roles with Scotiabank.

Jennifer F. Koury 2 4
>35 years of experience with focus in business leadership and governance. Former executive with BHP Billiton and Enerplus.

Jodi Jenson Labrie 1 4
>25 years of energy and professional services experience. Former SVP and CFO of Enerplus.

Francois Langlois 1 3 5
>35 years of domestic and international oil and gas experience. Former SVP, Exploration and Production with Suncor.

Myron M. Stadnyk 1 3 4
>35 years of business, industry, leadership and governance experience. Former President and CEO of ARC Resources.

Mindy Wight 4
>15 years of tax and financial experience. CEO for the Nch'kay Development Organization.

1 **Audit Committee**
Financial risk management
Cybersecurity
Financial Information

2 **CG & Nominating Committee**
Board renewal
Diversity
Governance

3 **ES&S Committee**
Stakeholder engagement
Environment
Safe operations

4 **HR & Compensation Committee**
Corporate culture
Compensation alignment
Employee engagement

5 **Reserves Committee**
Operational excellence

CG: Corporate Governance. ES&S: Environmental, Safety & Sustainability.

Forward Looking Information

This presentation contains “forward-looking statements” within the meaning of applicable securities legislation, such as section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934, including estimates of future production, cash flows and reserves, business plans for drilling and exploration, the estimated amounts and timing of capital expenditures, the assumptions upon which estimates are based and related sensitivity analyses, and other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance (often, but not always, using words or phrases such as “expects” or “does not expect”, “is expected”, “2025E” or “2029E”) and includes: approximately 20 years of premium inventory; expected proportions of 2025 production by area; 2025 production, development capital expenditures, excess cash flow and YE D/CF outlook; benefits of issuing investment grade notes; focused portfolio of high-return assets; generating long-term returns for shareholders; 2025E production by area; optimizing capital structure; expected net debt reduction; commitment to shareholder returns; consistently returning ~60% of excess cash flow; amount of shareholder returns expected and form thereof; returns-focused 2025 budget, including generating significant excess cash flow which is directed to shareholder returns and debt reduction, budget allocations by area, to facilities and to long-term projects; benefits of capital allocated to facilities; 2025 expected funds flow (at the commodity prices and assumptions specified), development capital expenditures, additional items, excess cash flow, dividend and share repurchases and debt reduction; 2025 outlook including, but not limited to, annual average production and portion of liquids production, development capital expenditures, excess cash flow (at the commodity prices and assumptions specified) and leverage ratio (at the commodity prices and assumptions specified); retaining flexibility to lower overall capital budget and allocation in response to weakness in commodity prices; strong and returns-focused 5-year plan; disciplined growth over 2025 to 2029 based on development capital expenditures specified and related production and liquids CAGR over the period; significant excess cash flow generation from 2025E to 2029E; excess cash flow CAGR (with and without share repurchases); key 5-year metrics at the commodity prices specified, including, but not limited to, cumulative excess cash flow, cumulative return of capital, net debt to funds flow at period end and percentage of market cap generated in excess cash flow; expected cash flow, development capital expenditures and production under the Company’s five year plan at the commodity prices specified; expected excess cash flow under five year plan at different WTI pricing assumptions; expected net debt reduction under five-year plan (at the commodity prices and assumptions specified); consistent return of excess cash flow levels; plans to prioritize share buybacks; return of capital framework and components; disciplined capital allocation driving significant excess cash flow & supporting shareholder returns plan to increase percentage allocation of excess cash flow over time to return of capital as the balance sheet strengthens further; the Company’s premium inventory and the Company’s development plans over the next five and 10 years; expected locations in corporate inventory and drilling locations in 10-year plan; the economics associated with the Company’s premium locations (at the commodity prices and assumptions specified); plans to enhance corporate returns through operational efficiencies and productivity improvements while maintaining capital discipline; portion of excess cash flow allocated to the balance sheet; disciplined hedging program and benefits thereof; maintain investment-grade credit rating and further enhance balance sheet strength; credit rating and trends; optimizing Montney well design; Alberta Montney returns; deep premium inventory in the Alberta Montney; Alberta Montney opportunities for down-spacing and step-out delineation; targeting enhanced returns in the Alberta Montney; Alberta Montney focused on optimizing infrastructure and related expected benefits; expected benefits of refined drilling and completions design in the Alberta Montney; high-quality position in the Alberta Montney; Alberta Montney five-year outlook (at the commodity prices and assumptions specified), including production CAGR, excess cash flow growth, production, capital expenditures, net operating income, production mix and excess cash flow mix; Alberta Montney and Kaybob Duvernay area economics (at the commodity prices and assumptions specified), including IP 30 rates, EUR, cost per well, NPV10%, payout, IRR and net locations; Alberta Montney drilling optimization plans; Alberta Montney break-even economics (at the commodity prices and assumptions specified); cost saving opportunities and corporate synergies associated with the Alberta Montney assets and the expectation of further synergies, including cost of capital improvement; scalability of Veren’s Alberta Montney; enhancing efficiencies and development in the Alberta Montney; value creation in the Kaybob Duvernay and Alberta Montney, including YE24 NPV and total unbooked premium drilling locations; Kaybob Duvernay asset overview, including, but not limited to, 2025E production and portion of liquids and condensate production, and production CAGR through 2029E, premium inventory and net locations, and strong netbacks generating significant excess cash, and portion of excess cash flow within the five-year plan; Kaybob Duvernay type well IP 30 rates and portion of liquids production; Kaybob Duvernay five-year outlook (at the commodity prices and assumptions specified), including production CAGR, excess cash flow growth, production, capital expenditures, net operating income, production mix and excess cash flow mix; Kaybob Duvernay unbooked locations and opportunity for down-spacing and further step-out delineation; Kaybob Duvernay delivering consistent results, high-returns and combination of growth and excess cash flow generation; focus in Kaybob on delivering consistent results and enhancing returns; improved Kaybob Duvernay efficiencies; development plan for Kaybob Duvernay; Kaybob Duvernay break-even economics (at the commodity prices and assumptions specified); Saskatchewan five-year outlook (at the commodity prices and assumptions specified), including excess cash flow growth, production, capital expenditures, net operating income, production mix and excess cash flow mix; Saskatchewan generating high netbacks; characteristics of Saskatchewan assets including, but not limited to, low decline, stable production and significant excess cash flow generation, potential reserves growth, improving returns, enhanced EURs, economics, capital efficiencies and unbooked locations associated with the OHML program; 2025 guidance, including, but not limited to annual average production, development capital expenditures and capitalized administration and other information as part of the 2025 guidance; return of capital outlook including target as a percentage of excess cash flow, total return of capital, dividends and share repurchases and funds flow sensitivities; net debt outlook for 2024 to 2029 (at the commodity prices specified) and long-term target leverage ratio in a low commodity price environment; credit rating and trends; extent, benefits and effectiveness of hedges; tax pools; expected 2024 and 2025 cash tax as a percentage of before tax cash flow for Company an peers (at the commodity prices and assumptions specified); expected demand for C5 and its impact on pricing; potential exposure to international natural gas pricing through future Ksi Lisims LNG project; strong market access; gas diversification; a breakdown of the Company’s expected 2025 oil and condensate production by stream; the metrics (at the commodity price indicated) associated with the Company’s portfolio of assets broken down by area, including average expected production, liquids percentage, royalty rates, operating expenses, operating netbacks, base decline rates and premium locations; the Company’s corporate strategy and how it guides the Company’s actions, goals and vision; the Company’s returns based capital allocation framework and excess cash flow priorities; the Company’s expected EXCF/share over the five-year plan; the Company’s plan to increase the percentage of capital retuned over time and the Company’s net debt reduction plans over the five-year plan; Alberta Montney Asset overview, including, but not limited to, 2025E production, portion of liquids production, production CAGR through 2029E, net locations in deep premium inventory, strong netbacks generating significant excess cash flow and percentage of corporate excess cash flow generated in five-year plan; Alberta Montney type well IP30 rates and percentage of liquids; 2P NPV calculations; and other assumptions inherent in management’s expectations in respect of the forward-looking statements identified herein. 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.

There are numerous uncertainties inherent in estimating crude oil, natural gas and NGL reserves and the future cash flow attributed to such reserves. The reserves and associated cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating expenses, all of which may vary materially. Actual reserve values may be greater than or less than the estimates provided herein. Also, estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates and future net revenue for all properties because of aggregation. Information relating to “reserves” is deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. All required reserve information for the Company is contained in its Annual Information Form for the year ended December 31, 2024, which is accessible at www.sedarplus.com. With respect to disclosure contained herein regarding resources other than reserves, there is uncertainty that it will be commercially viable to produce any portion of the resources and there is significant uncertainty regarding the ultimate recoverability of such resources. All forward-looking statements are based on Veren’s beliefs and assumptions based on information available at the time the assumption was made. Veren believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this report should not be unduly relied upon. By their nature, such forward-looking statements are subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements, including those material risks discussed in the Company’s Annual Information Form for the year ended December 31, 2024 under "Risk Factors“ and our Management’s Discussion and Analysis for the year ended December 31, 2024, under the headings "Risk Factors" and "Forward-Looking Information“. The material assumptions are disclosed in the Management’s Discussion and Analysis for the year ended December 31, 2024, under the headings "Capital Expenditures", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors" and "Changes in Accounting Policies". In addition, risk factors include: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas, decisions or actions of OPEC and non-OPEC countries in respect of supplies of oil and gas; delays or impediments in business operations or delivery of services due to pipeline restrictions, rail blockades, outbreaks or pandemics; uncertainty regarding the benefits and costs of acquisitions and dispositions; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; emissions cap legislation; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on Indigenous lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value and likelihood of acquisitions and dispositions, and exploration and development programs; unexpected geological, technical, drilling, construction, processing and transportation problems; the impact of drought, water availability, wildfires, severe weather events and climate change; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions; changes in interest rates and inflation; uncertainties associated with regulatory approvals; geopolitical conflicts, including the impacts of the conflicts in Ukraine and the Middle East; uncertainty of government policy changes; the implementation of tariffs and the results of trade negotiations; uncertainties associated with credit facilities and counterparty credit risk; cybersecurity risks; changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry; the wide-ranging impacts of the COVID-19 pandemic, including on demand, health and supply chain; and other factors, many of which are outside the control of the Company. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Veren’s future course of action depends on management’s assessment of all information available at the relevant time. In addition, with respect to forward-looking information contained in this presentation, assumptions have been made regarding, among other things: future crude oil and natural gas prices; future interests rates and currency exchange rates; future cost escalation under different pricing scenarios; the corporation's future production levels; the applicability of technologies for recovery and production of the corporation's reserves and improvements therein; the recoverability of the corporation's reserves; Veren’s ability to market its production at acceptable prices; future capital expenditures; future cash flows from production meeting the expectations stated in this presentation; future sources of funding for the corporation's capital program; the corporation's future debt levels; geological and engineering estimates in respect of the corporation's reserves; the geography of the areas in which the corporation is conducting exploration and development activities; the impact of competition on the corporation; the corporation's ability to obtain financing on acceptable terms. These assumptions, risks and uncertainties could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements. The impact of any one assumption, risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent. Except as required by law, Veren assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change. Certain information contained herein has been prepared by third-party sources. Included in this presentation are Veren’s 2025 guidance in respect of capital expenditures and average annual production, and 5-year plan and outlooks based on various assumptions as to production levels, commodity prices and other assumptions and are provided for illustration only and are based on budgets and forecasts that have not been finalized and are subject to a variety of contingencies including prior years' results. The Company’s return of capital framework is based on certain facts, expectations and assumptions that may change and, therefore, this framework may be amended as circumstances necessitate or require. To the extent such estimates constitute a “financial outlook” or “future oriented financial information” in this presentation, as defined by applicable securities legislation, such information has been approved by management of Veren. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management’s current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

Advisories

EXTERNAL, MARKET AND INDUSTRY DATA

Where this Presentation quotes any market and industry data and other statistical information from any external source, it should not be interpreted that the Company has adopted or endorsed such information or statistics as being accurate. The Company has obtained market and industry data and other statistical information presented in this Presentation from certain third-party information. Such third-party 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 the data or other statistical information contained therein, nor has it ascertained the underlying economic or other assumptions relied upon by these sources, accordingly, no representation or warranty, express or implied, is made as to, and no reliance should be placed on, the fairness, accuracy, completeness or correctness of this information or any other information or opinions contained herein, for any purpose whatsoever. The Company has no intention and undertakes no obligation to update or revise any such information or data, whether as a result of new information, future events or otherwise, except as required by law.

PRESENTATION OF FINANCIAL INFORMATION

The financial information of Veren referred to in this Presentation is reported in Canadian dollars and has been derived from audited and unaudited historical financial statements of Veren that were prepared in compliance with International Financial Reporting Standard ("IFRS").

NOTE TO READER REGARDING DISCLOSURE

In addition to obtaining all necessary Board approvals, the Company's long-established Disclosure Committee's mandate is to review and confirm the accuracy of the data and information contained in the documents, including this presentation, Veren uses to communicate to the public. This review and confirmation process is formally completed prior to any such disclosure being released. This Committee is comprised of senior representatives (including officers) from each of the following departments: accounting and finance; engineering and operations (including drilling and completions, environment, health and safety and regulatory); exploration and geosciences; investor relations; land; legal; ESG; marketing and reserves.

This presentation contains "forward-looking statements" within the meaning of applicable securities legislation, such as section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934, including estimates of future production, cash flows and reserves, business plans for drilling and exploration, the estimated amounts and timing of capital expenditures, the assumptions upon which estimates are based and related sensitivity analyses, and other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance. Please see the "Forward-Looking Statements" section of this presentation for additional details regarding such statements.

CREDIT RATINGS

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgement, circumstances so warrant.

Definitions / Specified Financial Measures

Throughout this presentation the Company uses the terms “funds flow” (equivalent to “adjusted funds flow”), “excess cash flow”, “excess cash flow per share – diluted”, “development capital expenditures”, “base dividends”, “total return of capital”, “total operating netback”, “operating netback”, “enterprise value”, “net debt”, “net debt / funds flow” (equivalent to “net debt to adjusted funds flow from operations” and to “leverage ratio”) and “net debt to annualized adjusted funds flow”, which are specified financial measures under National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure. Specified financial measures do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities.

For the year ended December 31, 2024, adjusted funds flow and excess cash flow were $2,347.8 million and $641.6 million, respectively. The most directly comparable financial measure for funds flow/adjusted funds flow and excess cash flow disclosed in the Company’s financial statements is cash flow from operating activities, which, for the year ended December 31, 2024 was $2,111.8 million. For the year ended December 31, 2024, development capital expenditures was $1,508.1 million. The most directly comparable financial measure for development capital expenditures disclosed in the Company’s financial statements is development capital and other expenditures, which for the year ended December 31, 2024 was $1,587.8 million. At December 31, 2024, net debt was $2,477.9 million. The most directly comparable financial measure for net debt disclosed in the Company’s financial statements is long-term debt, which at December 31, 2024 was $2,454.5 million. The most directly comparable financial measure for base dividends disclosed in the Company’s financial statements is dividends declared, which for the year ended December 31, 2024 was $284.6 million. For the year ended December 31, 2024, total operating netback from continuing operations was $2,576.7 million. The most directly comparable financial measure for total operating netback is oil and gas sales, which for the year ended December 31, 2024 was $4,271.3 million. Operating netback is a non-GAAP ratio and is calculated as total operating netback divided by total production. Operating netback is a common metric used in the oil and gas industry and is used to measure operating results on a per boe basis. For the year ended December 31, 2024, operating netback was $36.83/boe. Total return of capital is a supplementary financial measure and is comprised of base dividends, special dividends and share repurchases, adjusted for the timing of special dividend payments. Enterprise value is a supplementary financial measure and is calculated as market capitalization plus net debt. Excess cash flow per share – diluted is a non-GAAP ratio and is calculated as excess cash flow divided by the number of weighted average diluted shares outstanding. Excess cash flow per share - diluted presents a measure of financial performance to assess the ability of the Company to finance dividends, potential share repurchases, debt repayments and returns-based growth. Excess cash flow per share – diluted for the year ended December 31, 2024 was $1.04 per share. Net debt / funds flow is a capital management measure and is calculated as the period end net debt divided by the sum of adjusted funds flow from operations for the trailing four quarters. Net debt / funds flow as at December 31, 2024 was 1.1x. Net debt to annualized adjusted funds flow is calculated as the period end net debt divided by quarterly adjusted funds flow from operations multiplied by four. Net debt to annualized funds flow for the three months ended December 31, 2024 was 1.0x. Excess cash flow for 2025 to 2029 is a forward-looking non-GAAP measure, and is calculated consistently with the measures disclosed in the Company’s MD&A. Refer to the Specified Financial Measures section of the Company’s MD&A for the year ended December 31, 2024.

For an explanation of the composition of adjusted funds flow, excess cash flow, excess cash flow per share – diluted, development capital expenditures, base dividends, total return of capital, total operating netback, operating netback, enterprise value, net debt and net debt / funds flow and how they provide useful information to an investor and quantitative reconciliations to the applicable GAAP measures, see the Company’s MD&A available online for the year ended December 31, 2024 at www.sedarplus.com, or EDGAR at www.sec.gov and on our website at www.vrn.com. The section of the MD&A entitled “Specified Financial Measures” is incorporated herein by reference. There are no significant differences in the calculations between historical and forward-looking specified financial measures.

Management believes the presentation of the specified financial measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis. This information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

Reserves & Drilling Data

Where applicable, a barrels of oil equivalent ("boe") conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6Mcf:1bbl) has been used based on an energy equivalent 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 than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value.

This presentation contains metrics commonly used in the oil and natural gas industry, including “CAGR”, “payout”, “IRR”, “decline rate”, “reserves life index”, “replacement rate”, "F&D costs", “FDC”, "FD&A” and “recycle ratio”. These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies and, therefore, should not be used to make such comparisons. Readers are cautioned as to the reliability of oil and gas metrics used in this presentation. Management uses these oil and gas metrics for its own performance measurements and to provide investors with measures to compare the Company’s performance over time; however, such measures are not reliable indicators of the Company’s future performance, which may not compare to the Company’s performance in previous periods, and therefore should not be unduly relied upon. CAGR, or the compound annual growth rate of an investment or other unit of value, is the average annual amount it grows over a period of years assuming its reinvested during the period. Payout is the point at which all costs associated with leasing, exploring, drilling and operating have been recovered from the production of a well. It is an indication of profitability. IRR is a discount rate that makes the net present value (NPV) of all cash flows equal to zero in a discounted cash flow analysis. It is an indication of profitability. Decline rate is the reduction in the rate of production from one period to the next. This rate is usually expressed on an annual basis. Management uses decline rate to assess future productivity of the Company’s assets. Reserves life index is calculated as proved plus probable reserves divided by production, it is a measure of the longevity of the Corporation’s reserves. F&D costs, including change in FDC, and FD&A costs have been presented in this presentation because they provide a useful measure of capital efficiency. F&D costs and FD&A costs, including land, facility and seismic expenditures and excluding change in FDC have also been presented in this press release because they provide a useful measure of capital efficiency. Recycle Ratio is calculated as operating netback divided by F&D or FD&A. Management uses recycle ratio for its own performance measurements and to provide shareholders with measures to compare the Company’s performance over time. Replacement rate is the amount of oil added to the Company’s 2P reserves, divided by production. It is a measure of the ability of the Company to sustain production levels. Finding and development (F&D) costs are calculated by dividing the development capital expenditures by the applicable reserves additions. F&D costs can include or exclude changes to future development capital costs. Finding, development and acquisition costs (FD&A) are equivalent to F&D costs plus the costs of acquiring and disposing particular assets. Future development capital (FDC) reflects the best estimate of the cost required to bring undeveloped proved and probable reserves on production. Changes in FDC can result from acquisition and disposition activities, development plans or changes in capital efficiencies due to inflation or reductions in service costs and/or improvements to drilling and completion methods. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Proved reserves are reserves estimated to have a high degree of certainty of recoverability. Probable reserves are less certain to be recoverable than proved reserves and possible reserves are less certain than probable reserves.

The reserve data provided in this presentation presents only a portion of the disclosure required under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”). This presentation references 20 years of premium locations in corporate inventory, which amounts include booked and unbooked locations. Unbooked future drilling locations are not associated with any reserves or contingent resources and have been identified by the Company and have not been audited by independent qualified reserves evaluators. Expected well performance comes from analyzing historical well productivity within the geographic area outlined on the respective slides. The expected well is an average of our future planned inventory.

Certain terms used herein but not defined are defined in NI51-101, CSA Staff Notice 51-324 – Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities (“CSA Staff Notice 51-324”) and/or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 and the COGE Handbook, as the case may be.

The Company’s reserves were independently evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel") effective as at December 31, 2024. The reserves evaluation and reporting was conducted in accordance with the definitions, standards and procedures contained in the COGEH and NI 51-101. Also, estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates and future net revenue for all properties due to the effect of aggregation. All required reserve information for the Company is contained in its Annual Information Form for the year ended December 31, 2024, which is accessible at www.sedarplus.ca.

Reserves & Drilling Data

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

2P Organic Reserves Additions for the year ended December 31, 2024 consist of the following product types: 34% tight oil, 2% light & medium crude oil, 20% NGLs and 44% shale gas.

Additional information on NI 51-101 product types with respect to our 2P Organic Reserve Additions can be found in our Reserves Report for the year ended December 31, 2024 available on SEDAR+ and EDGAR.

Reserves & Drilling Data

Initial production is for a limited time frame only (30 days) and may not be indicative of future performance. Peak IP30 refers the 30 consecutive days with the highest production rates since a pad has come on production and may not be indicative of future performance. For additional product type information for our major operating areas, refers to our Reserves Report.

Type wells, EUR and IP30 are based on the expected results from Veren's premium drilling inventory, in accordance with the COGE handbook. These drilling locations include proved plus probable undeveloped reserves as evaluated by McDaniel & Associates Consultants Ltd. in addition to unbooked future drilling locations as identified by Veren.

This presentation discloses: (I) in the Kaybob Duvernay, (A) Volatile Oil region, 235 potential internally identified net drilling locations, of which 122 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 113 are unbooked locations; (B) Liquids-Rich region 125 potential internally identified net drilling locations, of which 53 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 72 are unbooked locations; and (C) Lean Gas region 160 potential internally identified net drilling locations, of which 25 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 135 are unbooked locations; (II) in the Alberta Montney, (A) Gold Creek West region, 310 potential internally identified net drilling locations, of which 98 are proved plus probable locations as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 212 are unbooked locations; (B) Gold Creek region 560 potential internally identified net drilling locations, of which 124 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 436 are unbooked locations; (C) Karr North region 425 potential internally identified net drilling locations, of which 102 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 323 are unbooked locations; and (D) Karr South region 135 potential internally identified net drilling locations, of which 107 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 28 are unbooked locations; and (III) in Saskatchewan, (A) Viewfield Bakken, 635 potential internally identified net drilling locations, of which 444 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 191 are unbooked locations; (B) Shaunavon 650 potential internally identified net drilling locations, of which 354 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 296 are unbooked locations; and (C) SE Conventional 185 potential internally identified net drilling locations, of which 57 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 128 are unbooked locations.

This presentation also discloses >5,000 locations in corporate inventory of which of which 1,486 are proved plus probable locations, as assigned in the company's year end 2024 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, with the remainder unbooked.

Years of corporate inventory figures include proved and probable locations, as derived from the independently evaluated (by McDaniel & Associates Consultants Ltd.) Reserves Report for Veren in accordance with NI 51-101 and the COGE Handbook, and additional internally identified net drilling locations. Company's ability to drill and develop new locations and the drilling locations on which the Company actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, the net price received for commodities produced, regulatory approvals and regulatory changes. As a result of these uncertainties, there can be no assurance that the potential future drilling locations that the Company has identified will ever be drilled and, if drilled, that such locations will result in additional crude oil, natural gas or NGLs produced. As such, the Company's actual drilling activities may differ materially from those presently identified, which could adversely affect the company's business. The estimates for reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation. The recovery and reserve estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

NI 51-101 includes condensate within the natural gas liquids (NGLs) product type. The Company has disclosed condensate as combined with crude oil and separately from other natural gas liquids in this presentation since the price of condensate as compared to other natural gas liquids 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.

Notice to US Readers

The oil and natural gas reserves contained in this presentation have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects of United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") generally permits oil and gas issuers, in their filings with the SEC, to disclose only proved reserves (as defined in SEC rules), but permits the optional disclosure of "probable reserves" and "possible reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only proved reserves (which are defined differently from the SEC rules) but also probable reserves and permits optional disclosure of "possible reserves", each as defined in NI 51-101. Accordingly, "proved reserves", "probable reserves" and "possible reserves" disclosed in this presentation may not be comparable to US standards, and in this presentation, Veren has disclosed reserves designated as "proved plus probable reserves". Probable reserves are higher-risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. "Possible reserves" are higher risk than "probable reserves" and are generally believed to be less likely to be accurately estimated or recovered than "probable reserves". In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalties and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments. Moreover, Veren has determined and disclosed estimated future net revenue from its' reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. Consequently, Veren's reserve estimates and production volumes in this presentation may not be comparable to those made by companies using United States reporting and disclosure standards. Further, the SEC rules are based on unescalated costs and forecasts. All amounts in the presentation are stated in Canadian dollars unless otherwise specified.

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