March 21, 2023

Kaybob Duvernay Analyst Teach-In

CRESCENT POINT

Bringing Energy To Our World - The Right Way

Agenda

- **Introduction** – Shant Madian, VP Capital Markets
- **Kaybob Duvernay Geology** – Mike Blair, VP Exploration & New Ventures
- **Operations** – Justin Foraie, VP Engineering & Marketing
- **Market Access and Infrastructure** – Ryan Gritzfeldt, COO
- **Corporate Portfolio and Outlook** – Ken Lamont, CFO
- **Closing Remarks** – Craig Bryksa, President & CEO
- **Q&A**

Presenters

Craig Bryksa
President & Chief Executive Officer
- Over 20 years of O&G experience
- Bachelor of Applied Science in petroleum engineering

Justin Foraie
VP, Engineering & Marketing
- 20 years of O&G experience
- Bachelor of Applied Science in petroleum systems engineering

Ken Lamont
Chief Financial Officer
- Over 30 years of industry experience (primarily O&G)
- Bachelor of Commerce (distinction) and a Chartered Accountant

Mike Blair
VP, Exploration & New Ventures
- Over 20 years of experience as a geologist
- Bachelor and Master of Science in geology

Ryan Gritzfeldt
Chief Operating Officer
- Over 20 years of O&G experience
- Bachelor of Applied Science in industrial systems engineering

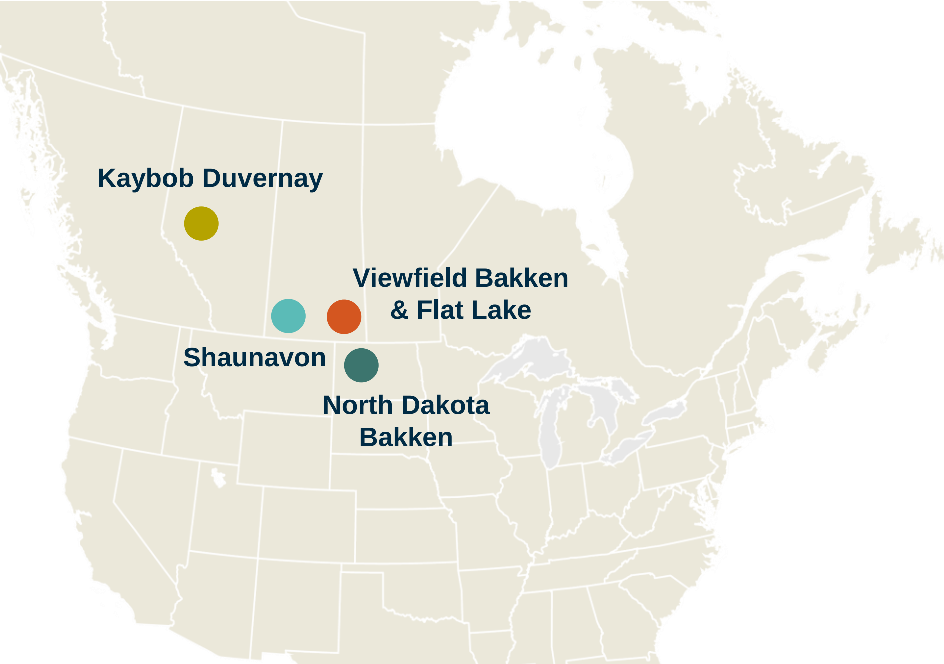
Shant Madian
VP, Capital Markets
- Over 20 years of capital markets experience (investment banking, equity research & institutional sales)
- Bachelor of Business Administration in Finance and a CFA charterholder

Crescent Point At A Glance

CPG (TSX and NYSE)	
Market Capitalization	$5.1 billion
Net Debt	$1.5 billion
Average Daily Trading Volume (Trailing 3-months)	13.6 million shares

Return of Capital Outlook	
Quarterly Base Dividend	$0.10/share (4.3% Yield)
Additional Return of Capital (Share Repurchases & Special Dividends)	50% (% of Discretionary Excess Cash Flow)

2023 Guidance & Excess Cash Flow	
Annual Average Production	138,000 - 142,000 boe/d (~80% Liquids)
Development Capital Expenditures	$1.0 - $1.1 billion
Excess Cash Flow (US$75 WTI & $3.50 AECO)	$1.0 billion

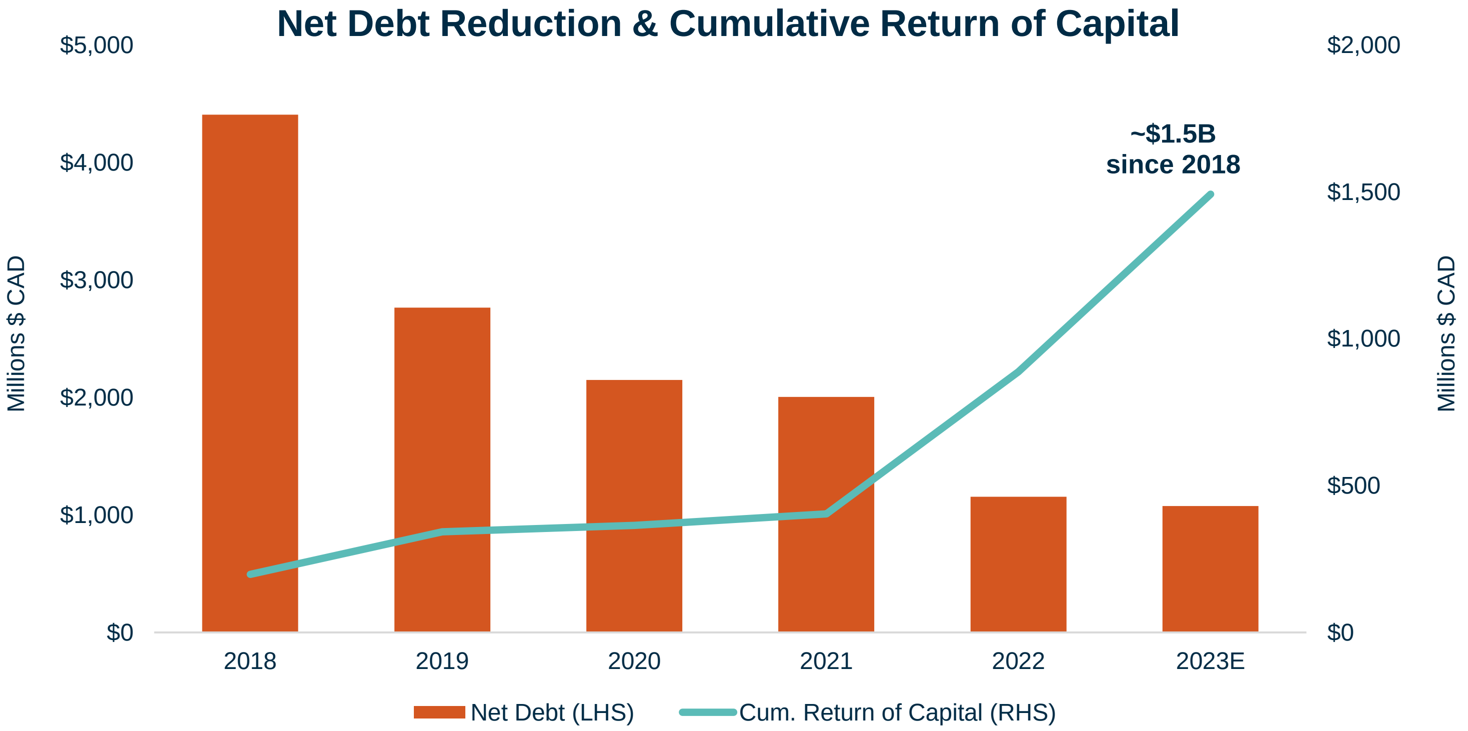


Reserve Life & Inventory	
Reserve Life Index (2P)	~15 years
Total Corporate Drilling Inventory	~5,000 locations

Net debt, discretionary excess cash flow and excess cash flow are specified financial measures - refer to the Specified Financial Measures section. Net debt as at Kaybob Duvernay asset acquisition close on January 11, 2023. Market capitalization and dividend yield based on shares outstanding and share price as of market close on March 10, 2023. Additional Return of Capital % is part of a framework that targets to return up to 50% of discretionary excess cash flow to shareholders. 2P: proved plus probable. See 'Reserves and Drilling Data' for a reconciliation of booked and unbooked locations.

Committed to a Strong Balance Sheet & Competitive Shareholder Returns

Since 2018, CPG has transformed its balance sheet and returned ~$1.5B directly to shareholders all within a disciplined capital allocation framework



Cumulative return of capital includes base dividends, share repurchases and special dividends. 2023E is based on US$75/bbl WTI and $3.50/mcf AECO, current guidance, the return of 50% of discretionary excess cash flow to shareholders and a dividend level of $0.10/sh per quarter in 2023. 2018 net debt is as of Q1 2018.

Crescent Point Advantage

Operational Excellence

- Premier operator with a strong track record of execution
- Innovative and highly technical team unlocking value
- Extensive knowledge in secondary recovery (waterflood)

Shareholder Returns

- Returning 50% of discretionary excess cash flow, in addition to base dividends
- Targeting low-to-mid single-digit growth
- Additional debt reduction

Disciplined Team

Long-term strategy built on key pillars of balance sheet strength and sustainability

Differentiated Portfolio

- Industry leading netbacks
- 80% oil & liquids production
- Strong market access and low decline rate

Balance Sheet Strength

- Significant financial liquidity
- Low leverage ratio of ~0.5x adjusted funds flow
- Significant tax pools (~$9B) enhance excess cash flow

Leverage ratio and adjusted funds flow are specified financial measures – refer to the Specified Financial Measures section.

CPG's Portfolio Optimization

Continually optimizing portfolio around key pillars of balance sheet strength and sustainability

Asset Criteria

- ☑ High Returns
- ☑ Scalability
- ☑ Excess Cash Flow Generation
- ☑ Market Access
- ☑ ESG

The Kaybob Duvernay asset, bolstered by our technical expertise, has significantly enhanced our long-term profitability and per-share metrics

Enhanced Profitability

Maturity

Initial Growth / Expansion

CPG's Recent Portfolio Optimization

Acquisitions ($1.35B)	Dispositions ($2.0B)
Kaybob Duvernay High returns Scalability & inventory Significant excess cash flow Excellent market access Strong ESG	**Uinta Basin** Poor market access **SE SK Conventional** High operating expenses, significant ARO and limited scalability **Viking** Limited scalability and high emissions intensity **Other Minor Non-Core** Willesden Green, East Shale Duvernay and other **Certain Infrastructure**

Recent portfolio optimization represents transactions since 2018. ARO: Asset retirement obligations.

Key Takeaways

Executing a disciplined corporate strategy to create long-term shareholder value

- ✓ Focused on maintaining **balance sheet strength** and driving long-term **sustainability**
- ✓ **Disciplined A&D strategy** with defined asset criteria in place (~$2.0B of dispositions and $1.35B of acquisitions since 2018)
- ✓ **Strong NAV per share growth** from Kaybob is creating significant shareholder value

CPG's operational excellence has enhanced overall returns in the play with industry-leading results

- ✓ Kaybob Duvernay drives the company's long-term plan, which includes **$3.0 – $5.8B of cumulative excess CF over the next 5 years**
- ✓ Our approach to drilling and completions has **realized cost efficiencies and improved well productivity**
- ✓ **Public data is inaccurate** and does not reflect the actual liquids-rich nature of the production

Kaybob Duvernay is a high-return, condensate-rich play that provides a combination of growth & excess CF

- ✓ History of the play and how the **basin has evolved over the years**
- ✓ CPG is strategically positioned in the **geological "sweet spot" of the Kaybob fairway**
- ✓ **Major infrastructure and market access already in place** to support CPG's disciplined growth strategy

NAV: Net asset value. A&D: Acquisition and disposition. Cumulative excess cash flow (CF) based on a forecast of US$65 to US$85 WTI.

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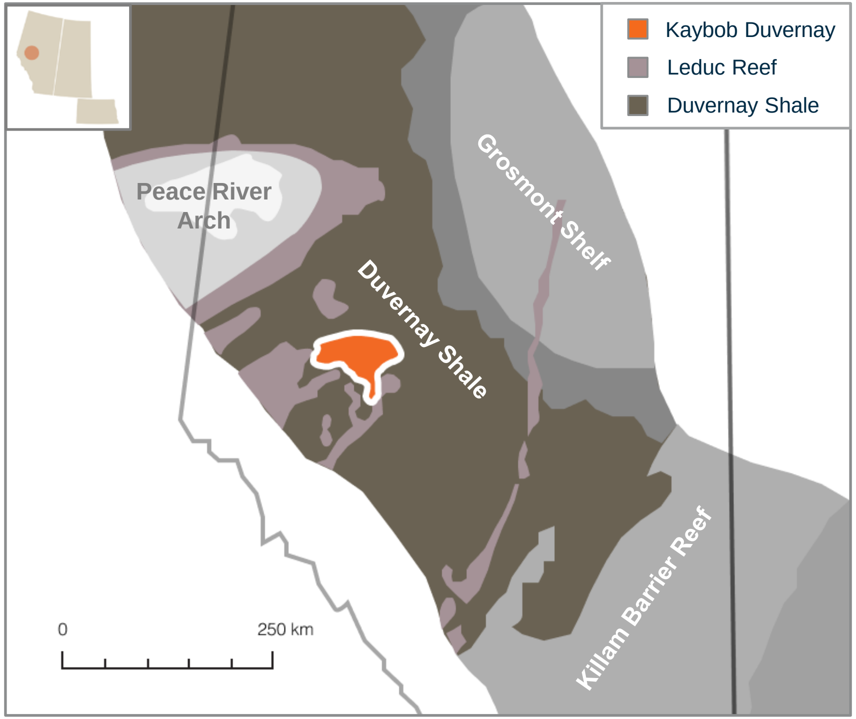
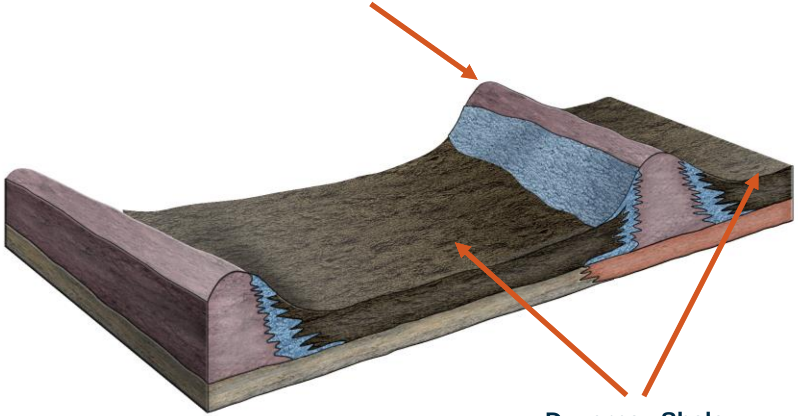
Kaybob Duvernay – A Consistent, Predictable Shale Basin

Targeting Duvernay (black) shale, characterized as consistent, extensive & predictable throughout the basin



Leduc Reef Complex
(Steep reefs bounding the shale reservoir)



Duvernay Shale
(High condensate and liquids content)

Recent Duvernay depositional environment (*Stoakes 1980*).

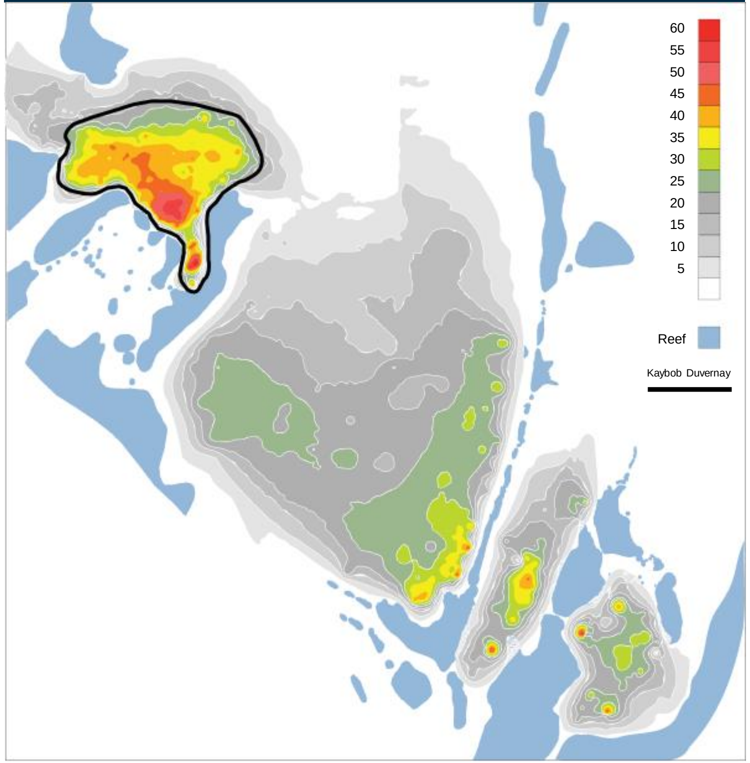
Kaybob Duvernay Comparison from a Geological Perspective

The Kaybob Duvernay compares favourably with other high-quality resource plays

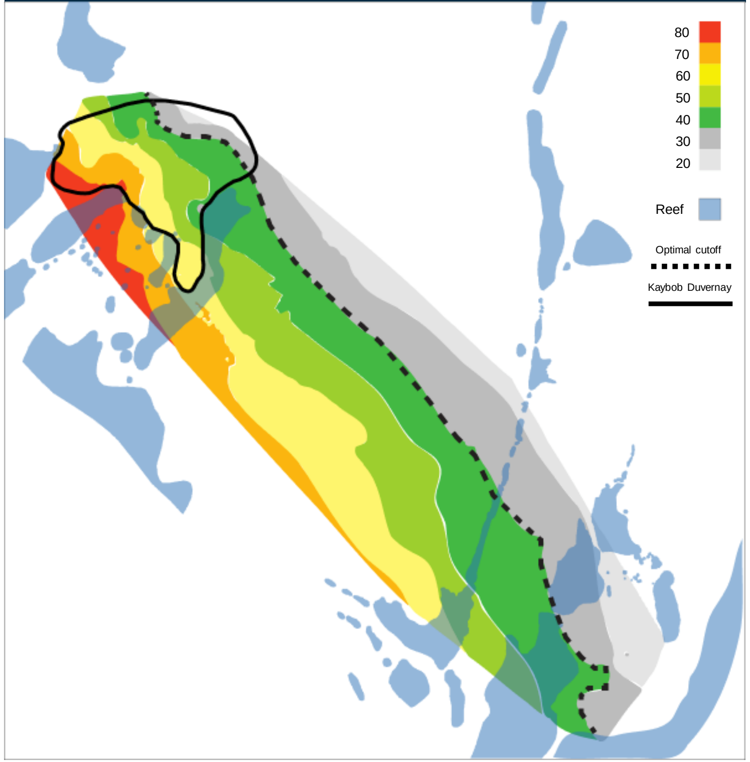
Key Attributes of High-Quality Resource Plays (In order of Importance)	CPG's Kaybob Duvernay	Alberta Montney Bench	Eagle Ford
Thickness (Net Pay): A measure of overall resource in place	**30 - 60 meters**	30 - 80 meters	30 - 80 meters
Pressure: Driver for productivity and ultimate recovery factors	**45 - 75 MPa**	20 - 45 MPa	40 - 75 MPa
Maturity: Indication of the various hydrocarbons that are in place	**Volatile oil, liquids-rich and lean gas windows**	Similar	Similar
Depth: Correlated to well costs, capital efficiencies and returns	**3,000 - 3,400 meters**	Similar	Similar

Geological Attributes of CPG's Kaybob Asset Within the Duvernay Fairway

Thickness (Net Pay) (Meters)



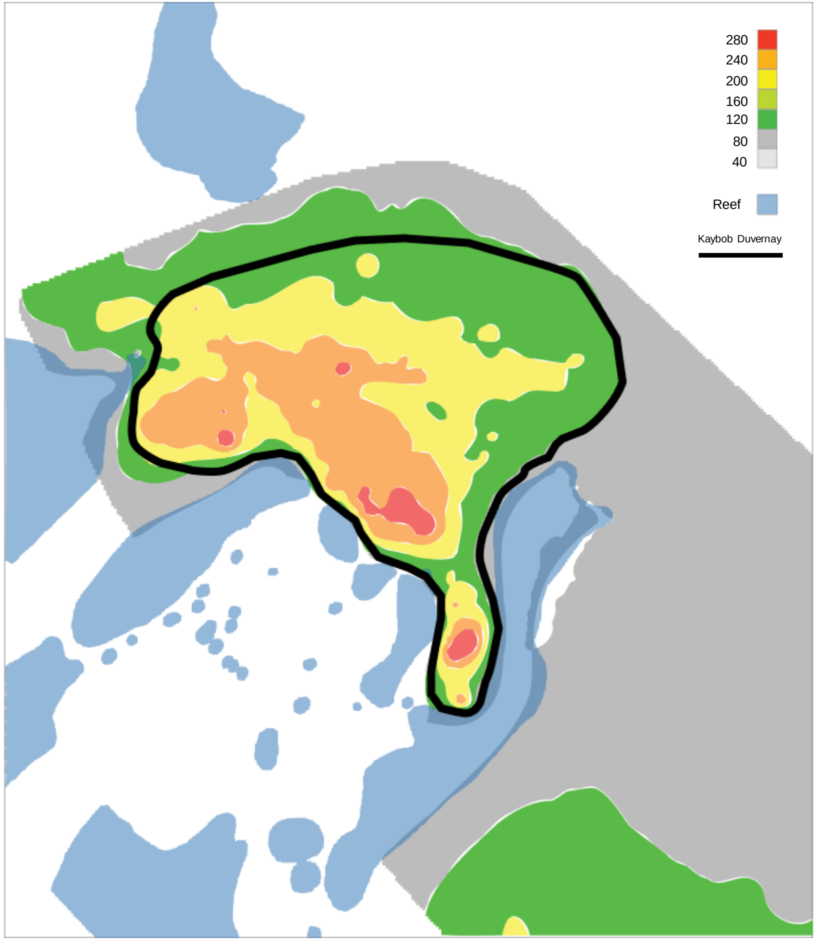
Pressure (MPa)



Depiction of Asset Quality When Combining Pressure x Thickness

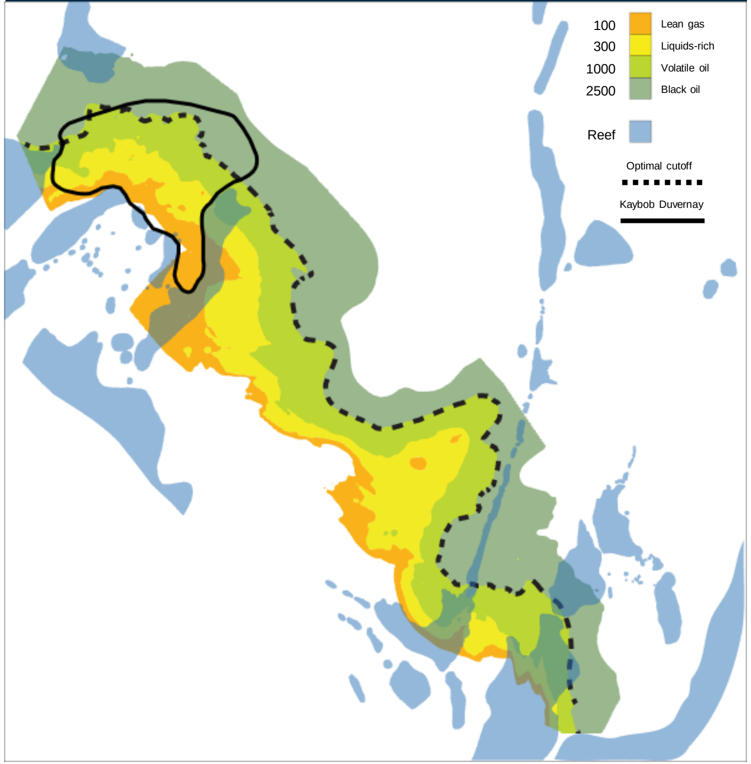
- CPG's lands are strategically positioned within the Duvernay fairway with optimum reservoir thickness and pressure

- Together these geologic factors drive:
  - Higher ultimate recovery
  - Strong well results
  - Competitive economics

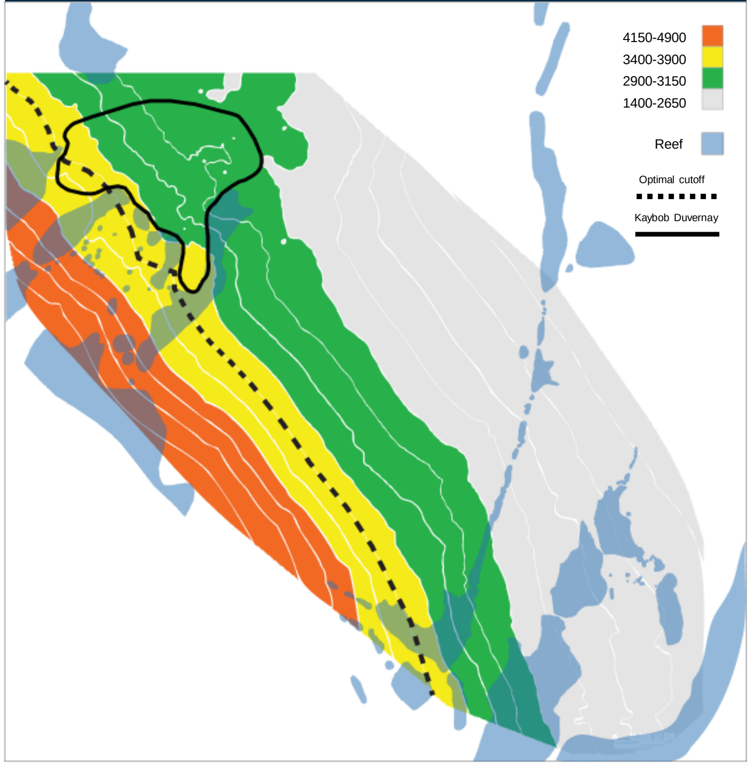


Geological Attributes of CPG's Kaybob Asset Within the Duvernay Fairway

Maturity



Depth (Meters)

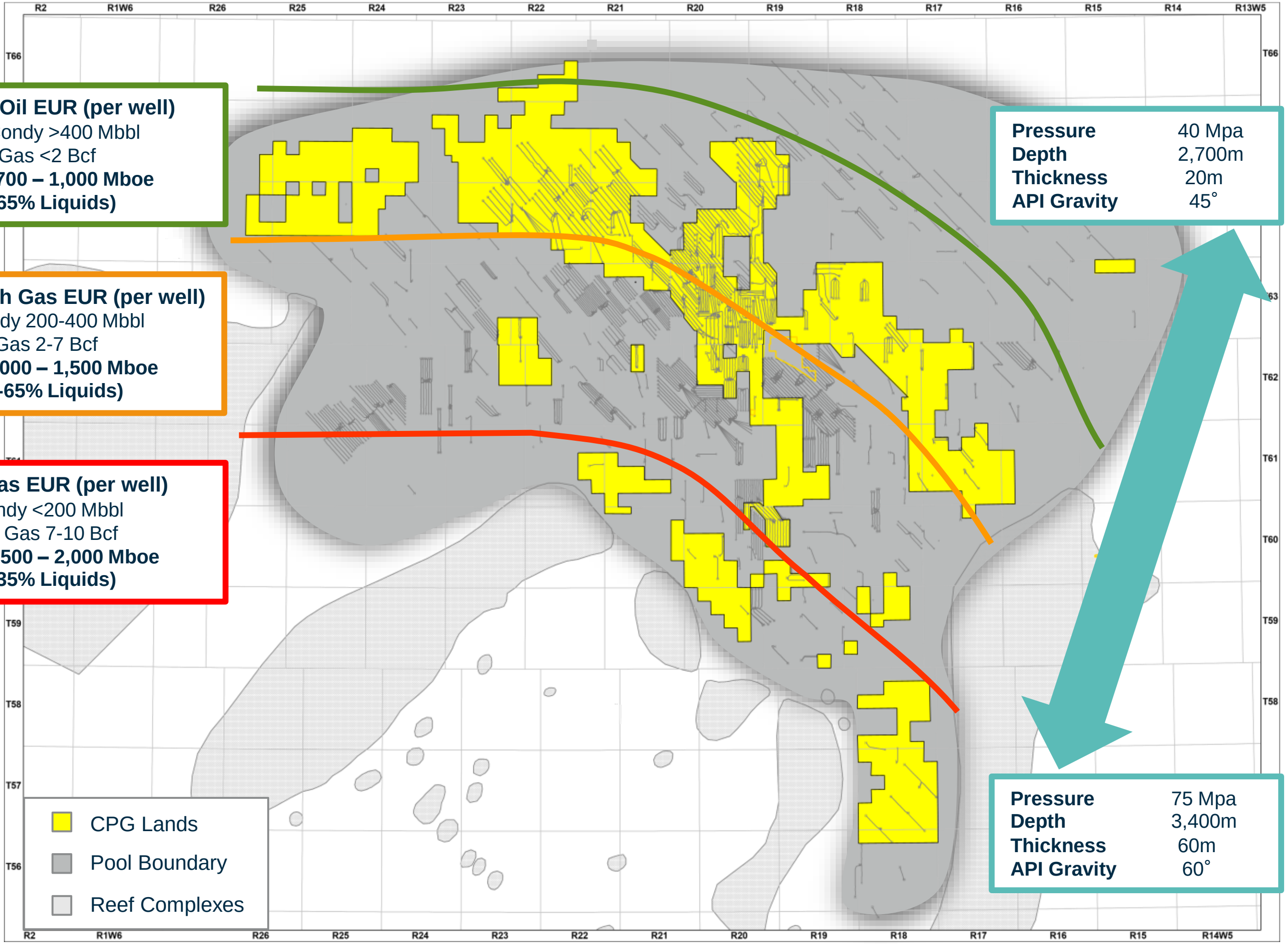


Kaybob Duvernay Reservoir Regions Illustrate Condensate-Rich Production

Volatile Oil EUR (per well)
Condy >400 Mbbl
Gas <2 Bcf
CPG: 700 – 1,000 Mboe
(>65% Liquids)

Liquids Rich Gas EUR (per well)
Condy 200-400 Mbbl
Gas 2-7 Bcf
CPG: 1,000 – 1,500 Mboe
(35-65% Liquids)

Lean Gas EUR (per well)
Condy <200 Mbbl
Gas 7-10 Bcf
CPG: 1,500 – 2,000 Mboe
(<35% Liquids)



Pressure	40 Mpa
Depth	2,700m
Thickness	20m
API Gravity	45˚

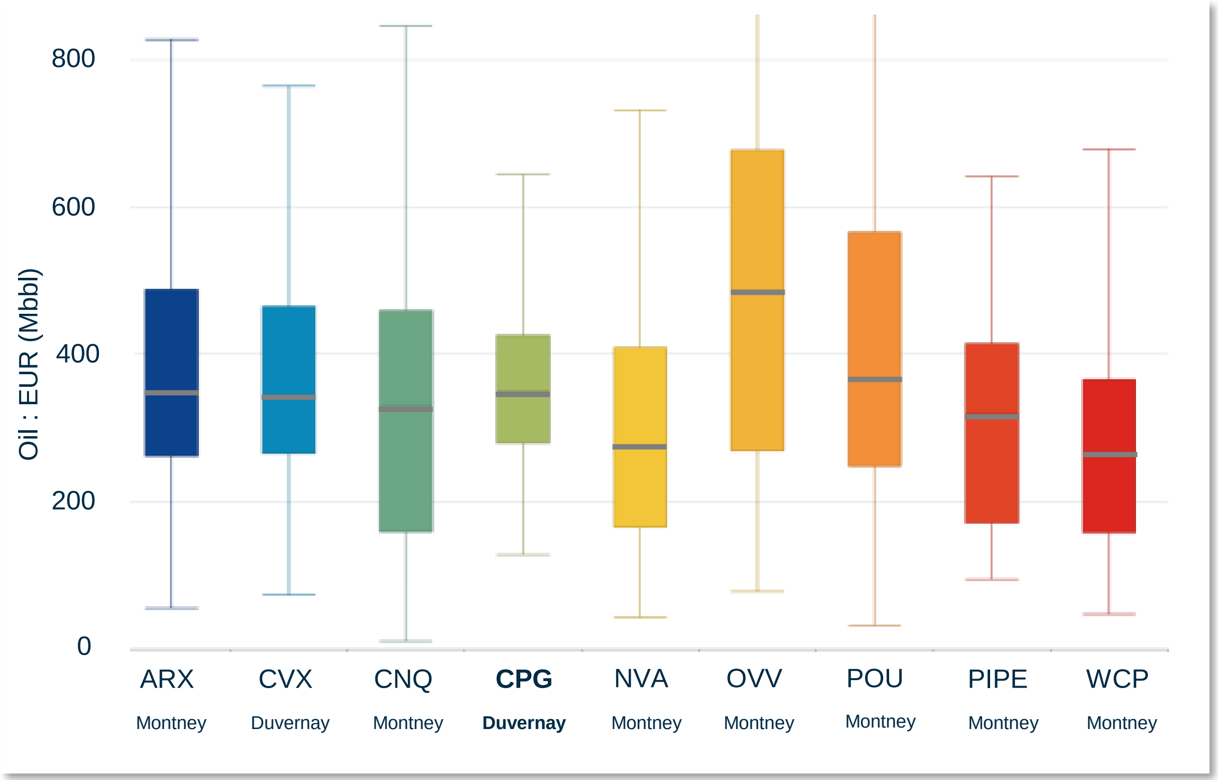
Pressure is 1.4x greater than the norm for this depth

Pressure	75 Mpa
Depth	3,400m
Thickness	60m
API Gravity	60˚

Pressure is >2.0x greater than the norm for this depth

Comparison to the Montney (2019 – 2022)

Geology in the Duvernay has resulted in a statistically tighter band of EUR ranges and more consistent results



- Oil/Condensate EURs are very similar to a typical Montney well
  - Also similar across the various windows in each basin (volatile oil, liquids-rich and lean gas)
- Gas EURs in the lean gas windows also have similar productivity
- Average porosities are comparable
- The permeability in the Kaybob Duvernay is lower, however, this is offset by higher pressures
- CPG's six fully-operated pads currently on-stream were booked at YE 2022 with an average condensate EUR of >450 Mbbl

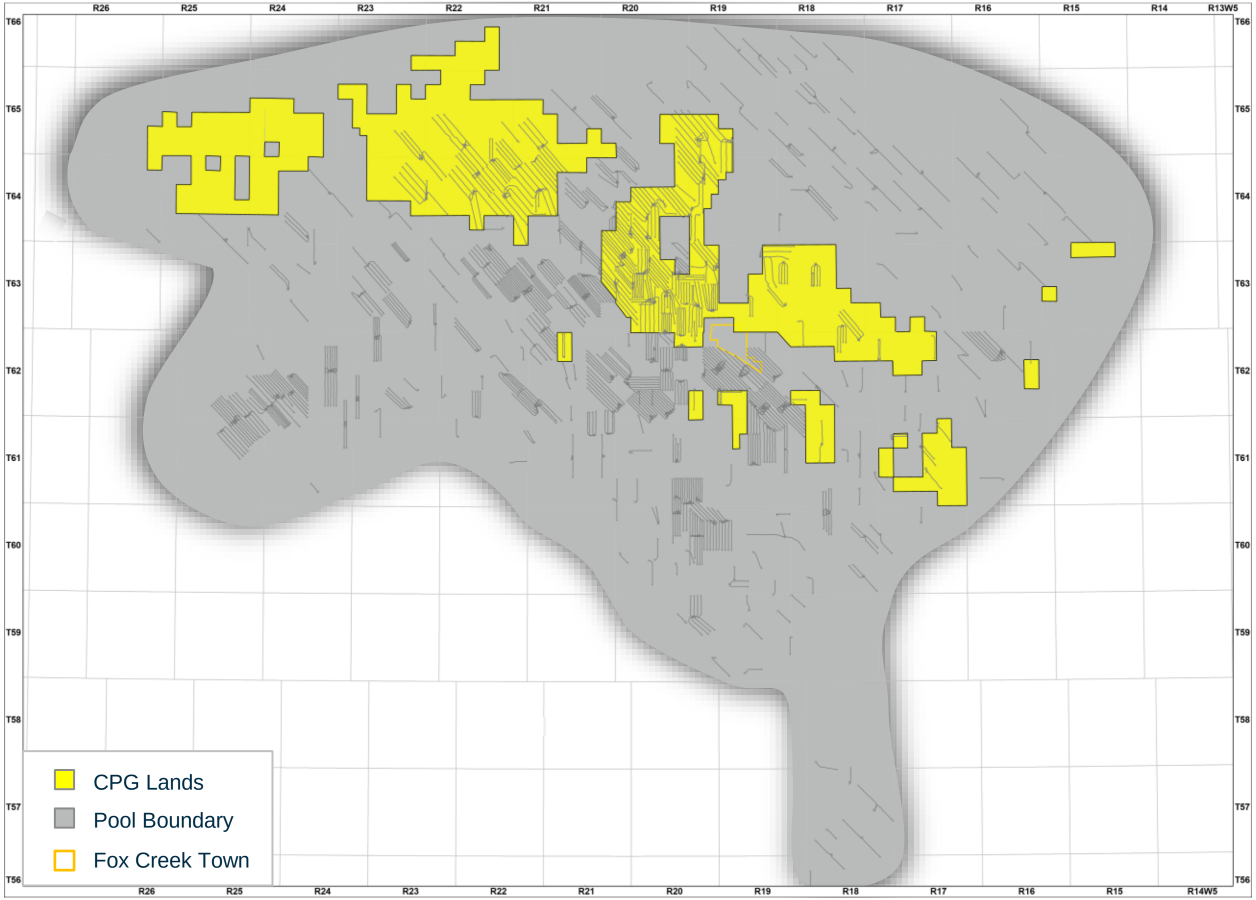
Source: McDaniel & Associates Research (independent qualified reserves evaluators).

Q2 2021: Strategic Entry Into the Basin to Acquire a Strong Foothold

Acquired assets from Shell Canada for ~$900MM (fully paid off in Q1 2023, within 2 years)

Strategic rationale:

- Dominant position in the volatile oil window
- Significant infrastructure in place (owned and third-party)
- ~30,000 boe/d providing immediate excess cash flow
- High-return, undeveloped drilling locations for additional upside



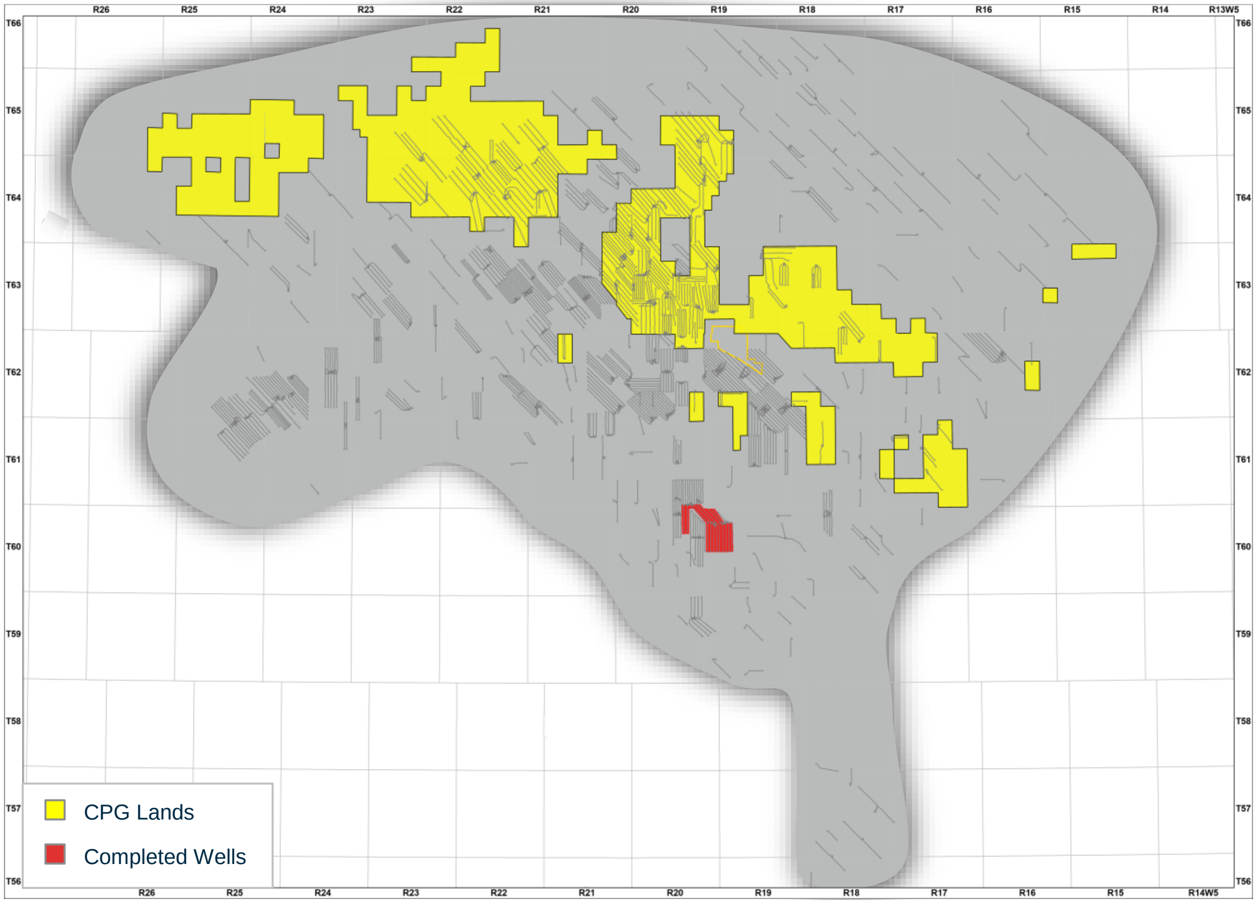
Two-year payback on the original Kaybob acquisition assumes US$75 WTI and $3.50 AECO for Q1 2023.

Q3 2021: Farm-In Agreement to Gain Additional Knowledge

Entered into a farm-in agreement to complete a certain number of wells to earn 50% working interest in such wells and additional lands in the play

Strategic rationale:

- Allow CPG team to complete wells for additional learnings while also testing productivity in the liquids-rich window



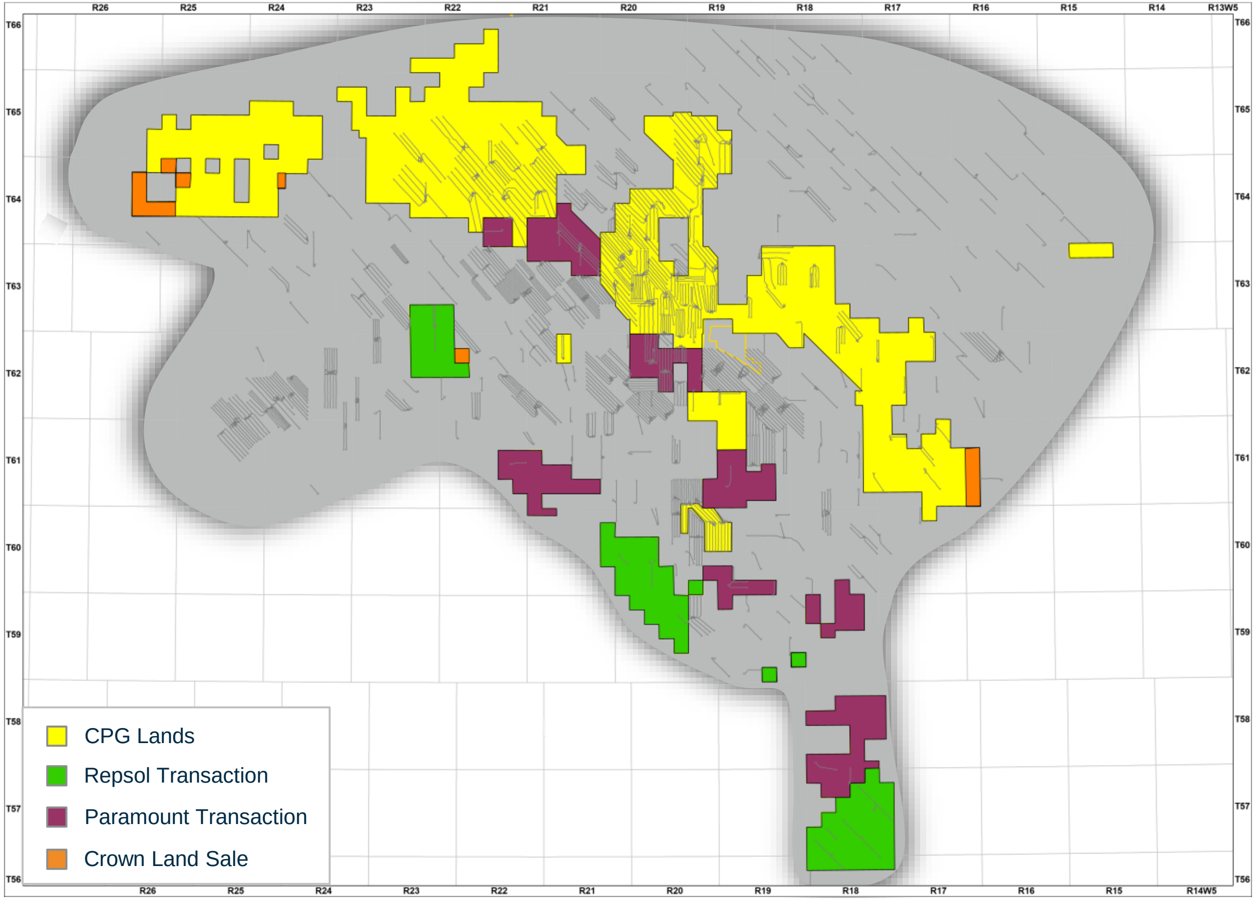
Q3 2022 to Q1 2023: Opportunistic Transactions

Acquired >50,000 net acres from Repsol and associated infrastructure ($87MM)

Acquired ~65,000 net acres from Paramount Resources, in addition to >4,000 boe/d and associated infrastructure ($370MM)

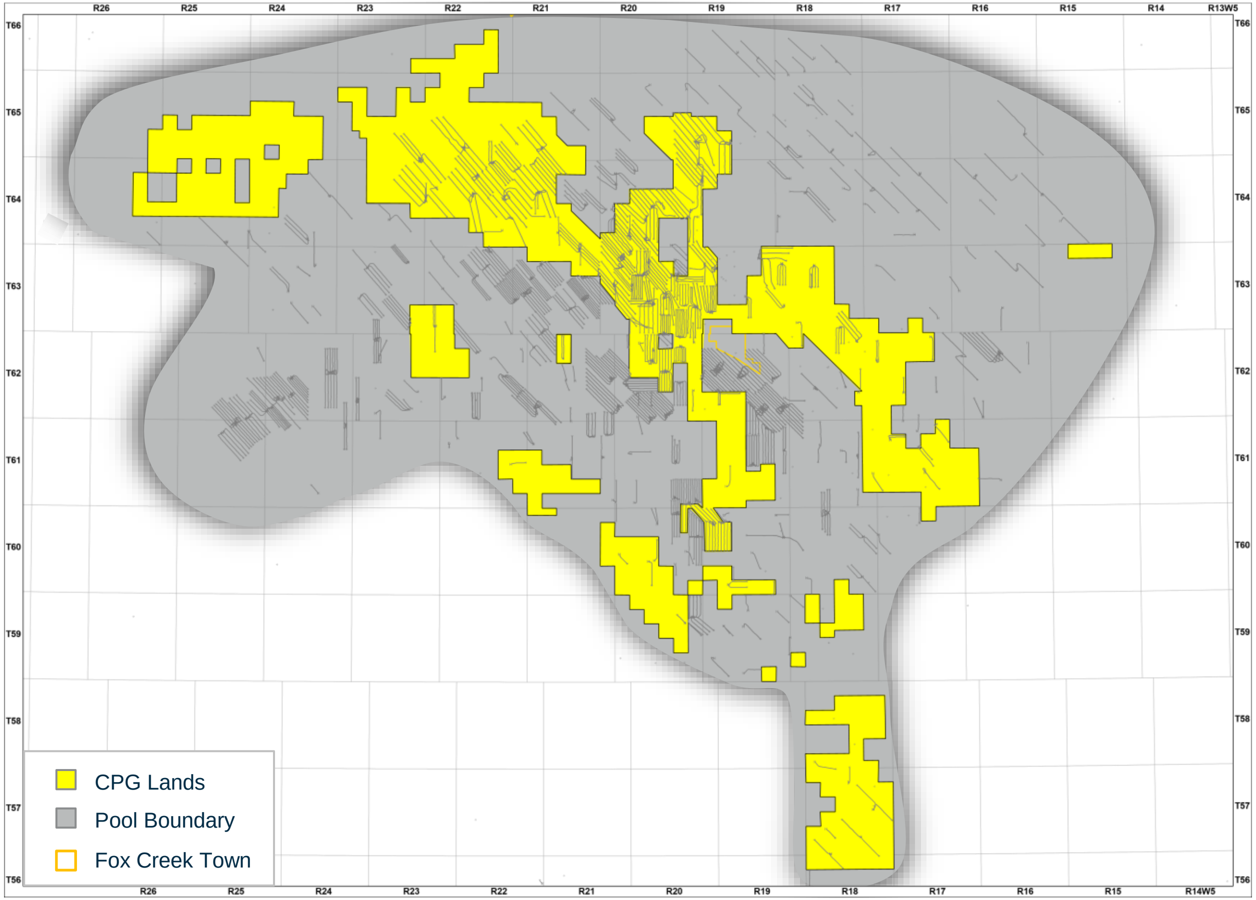
Strategic rationale:

- Bolt-on land contiguous to existing land position providing enhanced efficiencies
- Expand inventory in liquids-rich window
- Additional optionality in high-pressure lean-gas window



CPG's Current Kaybob Duvernay Position

Key Metrics	Current	Change Since Entry
Production (boe/d)	45,000	+50%
Net Acres	400,000	+35%
Net Locations	500	+175%
CPG Wells Drilled / Completed	32 / 48	



All figures are approximates. Current production is forecast for annual average in 2023.

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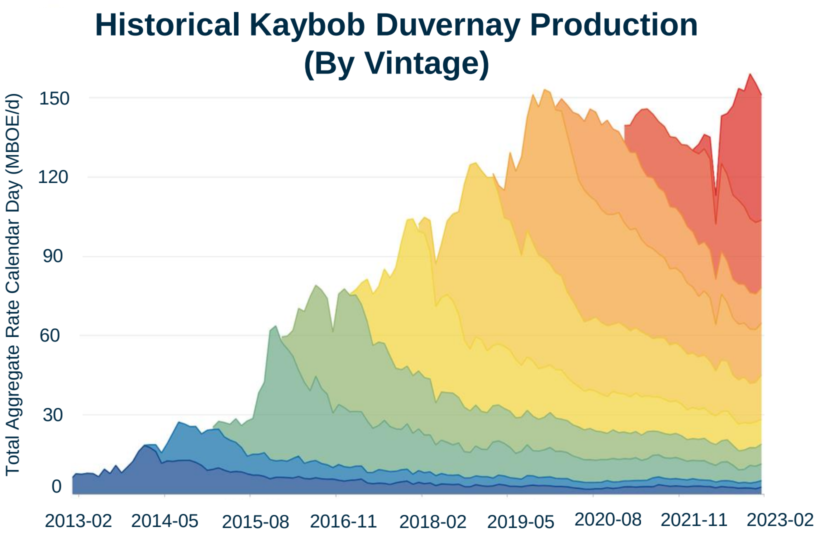
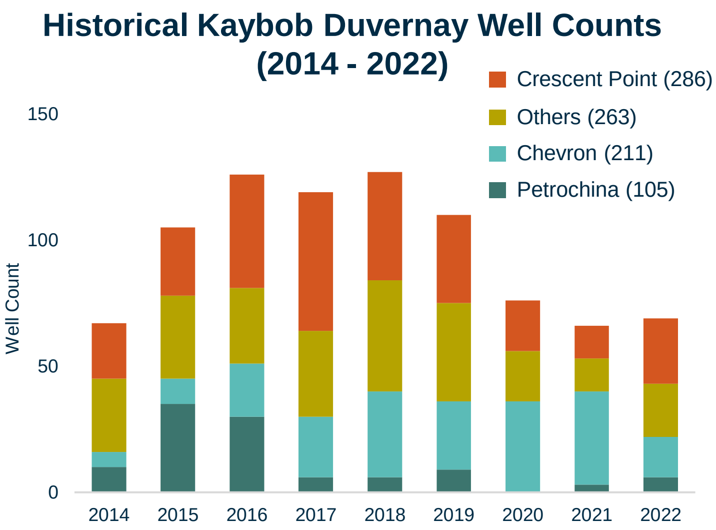
Kaybob Duvernay – Increased Basin Production from Fewer Wells

Returns and well results have improved over the years due to new technologies and efficiency improvements

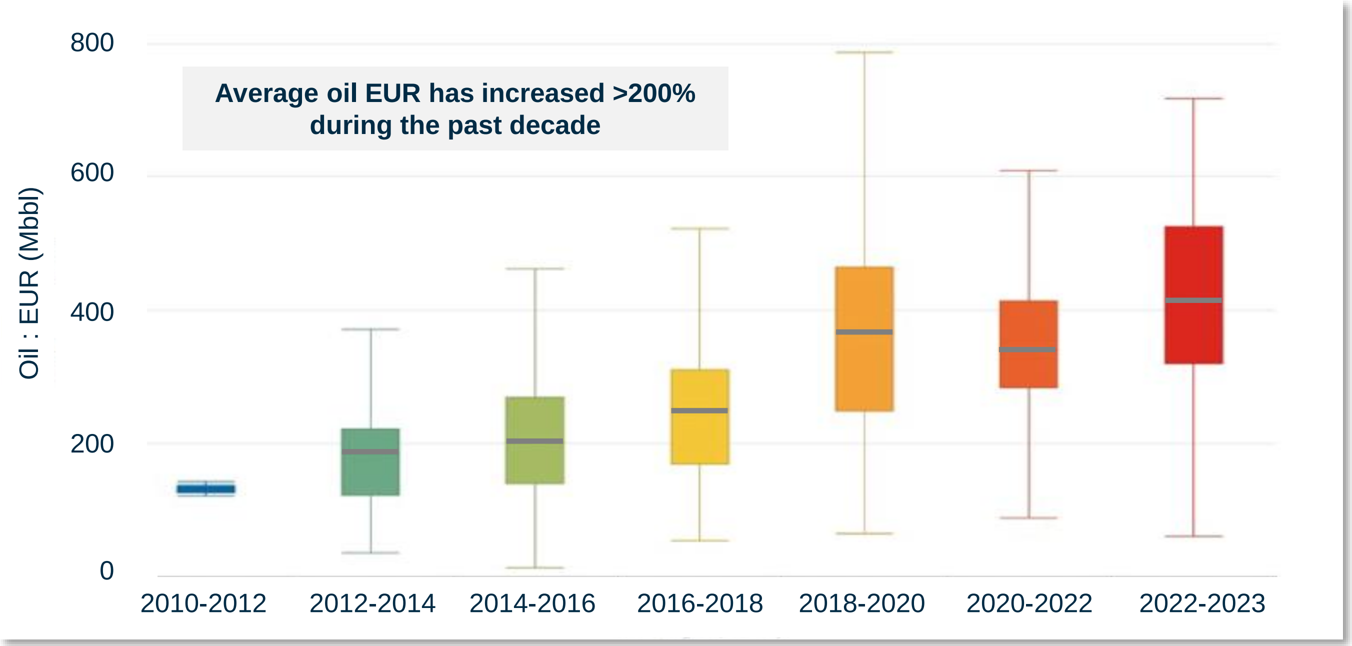
- **Total basin production of ~150,000 boe/d** (43% liquids)
  - ~8% CAGR over the last five years
  - **CPG represents ~30%** of total basin production
- Total production has grown in recent years despite lower well counts, highlighting improvements in overall well productivity
- **CPG is a premier operator** in the play based on scale and drilling activity





Source: McDaniel & Associate Research. Historical well counts include wells drilled by prior operators.

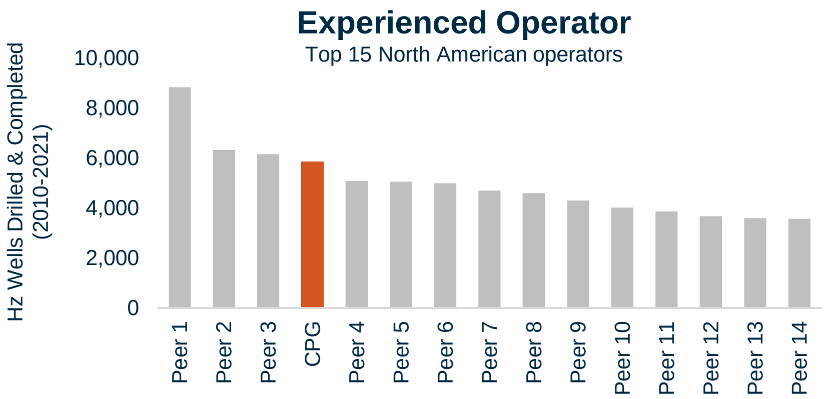
Advancements in Drilling & Completions Practices Driving Increased EURs



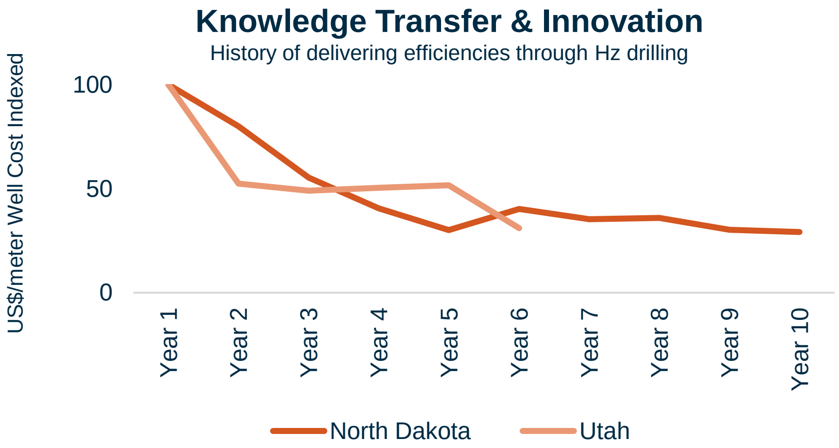
	First Wells By Industry	→ First Pads & Delineation → Modern Completions → Continued Development & Optimization →	Current Design By Industry
Lateral Length	**1,200 m**	Longer lateral lengths to enhance total EURs and efficiencies on a cost per meter basis	**>3,200 m**
Fluid Loading	**11 m^3/m**	Increased fluids to create more conductive fractures of the rock during the completions process	**18 m^3/m**
Sand Loading	**1.0 T/m**	Concurrently increasing sand tonnage (proppant loading) to hold open these larger fractures	**>3.0 T/m**
Cluster Spacing	**50 m**	Tighter cluster spacing (# of frac perforations per lateral length) to increase stimulation along Hz well	**14 m**

Source: McDaniel & Associates Research, CPG and public information from peers in the basin.

Track Record of Realizing Efficiencies in Plays Similar to Kaybob Duvernay



- CPG has a history of operational execution and continuous improvement across North American resource plays, including those with similar characteristics to the Kaybob Duvernay (i.e. North Dakota and the Uinta Basin)
- CPG immediately applied learnings to the Kaybob Duvernay and successfully realized well cost reductions of ~20% within the first year



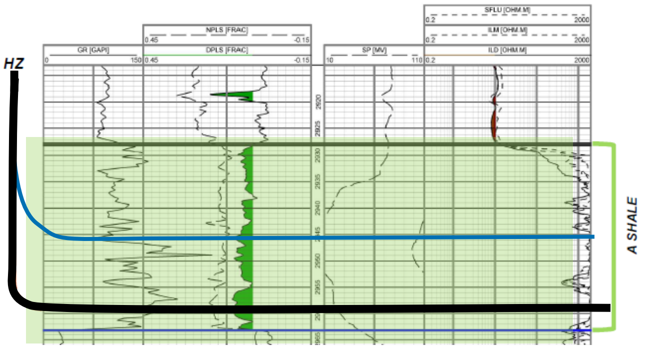
	Kaybob Duvernay	North Dakota	Uinta (Utah)
Avg. Drilling Depth (m)	>3,000	~3,000	~2,500
Reservoir Pressure (Mpa)	45 – 75	40 – 50	30 – 55
Hz Drill Count	~32	~215	~80
2-Mile Hz Drilling	✓	✓	✓
Multi-Well Pad Development	✓	✓	✓

Horizontal Wells Drilled source: Enverus; peers include CHK, CLR, CNQ, COP, CVE, CVX, DVN, EOG, MRO, OVV, OXY, PXD, WCP & XOM. Asset characteristics based on CPG land and development in each play.
North Dakota cost savings per meter calculated as the change in average cost per meter lateral between 2011-2021; Utah cost savings per meter calculated as the change between 2014-2019 (asset sold in 2019)

Demonstrating Technical Expertise

New CPG landing depth helps to contain the hydraulic fractures to target additional higher quality rock

15-1-63-18w5 Well Log

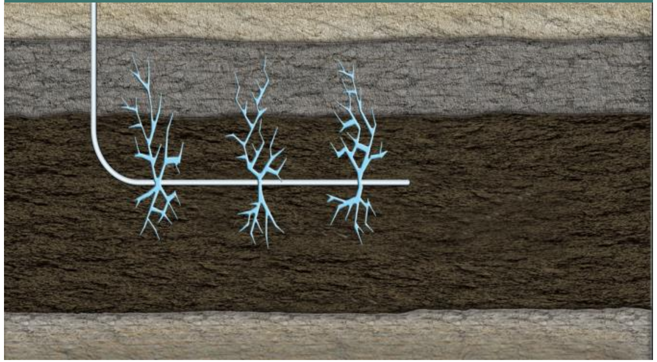


Lowered landing zone in thick uniform geology to have a more uniform frac and ultimately more stimulated rock/well

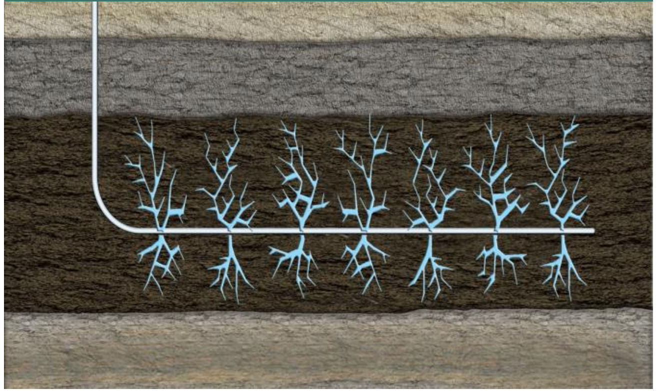
Prior Operator landing zone

CPG landing zone

Prior Operator Landing Zone



CPG Landing Zone



Experience & Expertise Driving Reduced Drilling Days

Lowered drilling days ~40% since entering the play, ranging 11 – 13 days per well on most recent pads

Phase 1

- Changes to drilling fluid and downhole pressure management to improve intermediate and lateral section drilling times

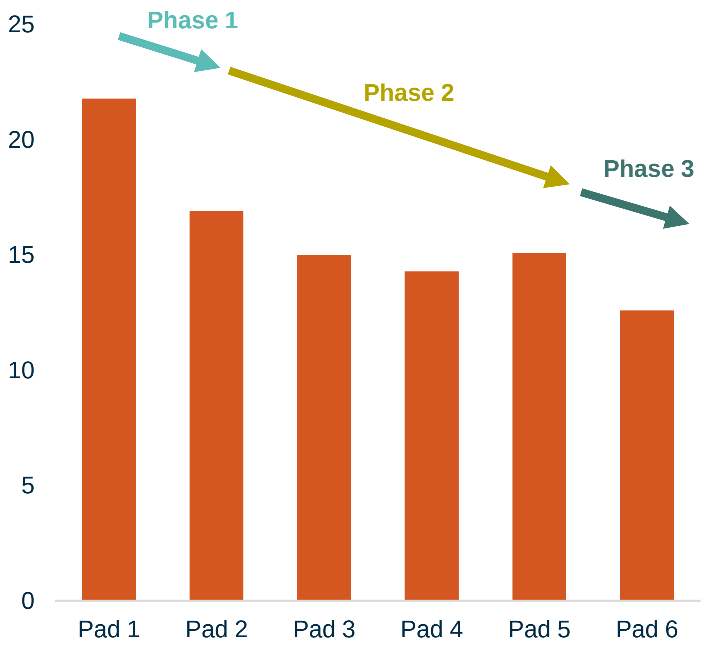
Phase 2

- Optimize drilling parameters and bottomhole equipment (i.e. drill bits, motors, steering settings, etc.)
- Continued changes to drilling fluid and downhole pressure management reduced casing running time

Phase 3

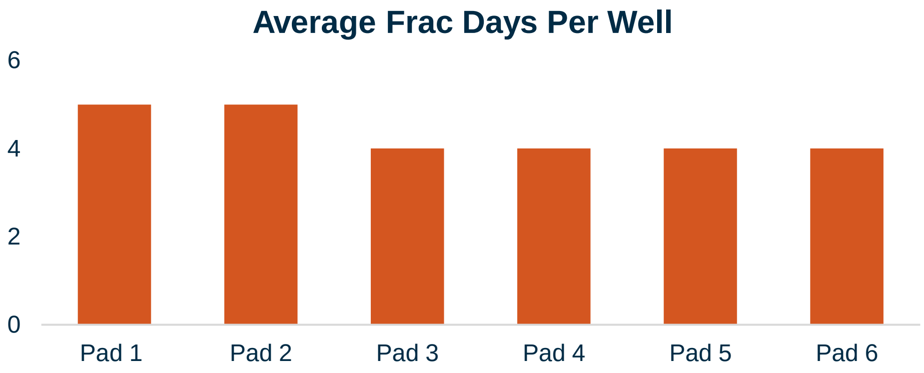
- Successful surface and downhole equipment trials
- Continued cycle time improvements prior to running casing

Average Drilling Days Per Well



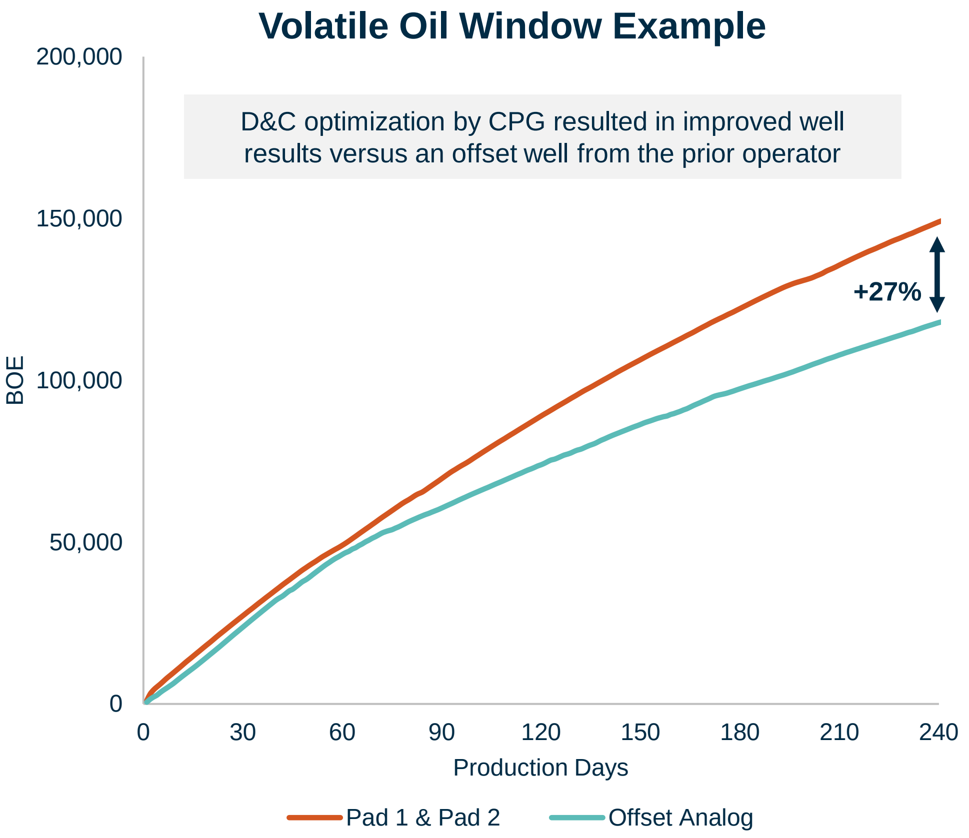
Experience & Expertise Driving Lower Completion Costs

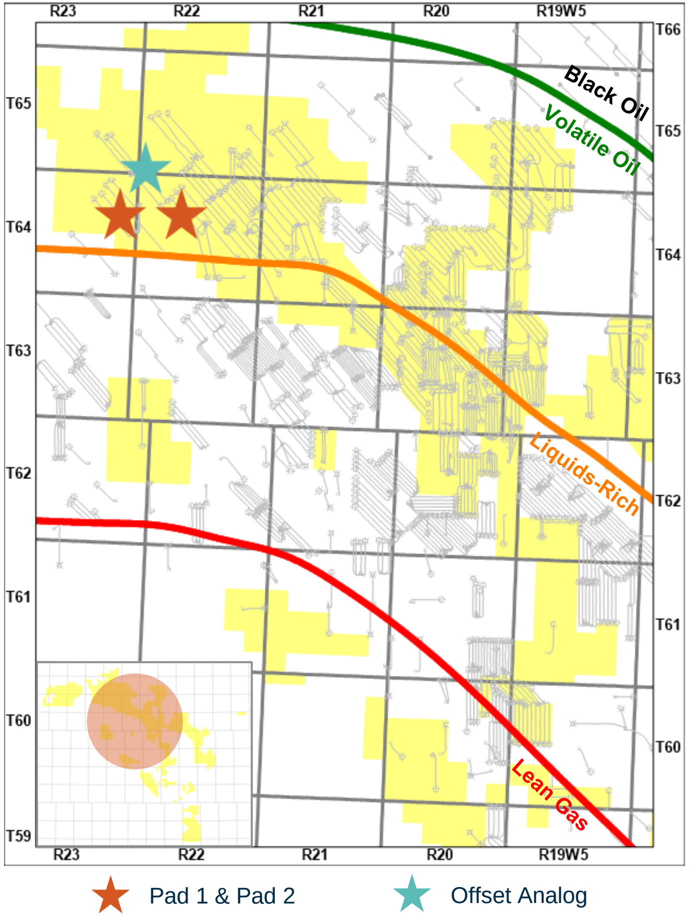
Reduced frac days per well ~20% while enhancing completions design since entering the play in Q2 2021



	Prior to Q2 2021	Q1 2023	
Completions Cycle Time	5 days/well	4 days/well	Consistent max pumping efficiency and removal of initial perf run with new toe port design
Sand Loading	2.5 T/m	3.0 T/m	Increase in stimulated rock volume
Fluid Loading	12 m^3/m	17m^3/m	Increase in frac half-length and reservoir drainage
Stage Spacing	80m	70m	Better frac efficiency and contact with the reservoir
Cluster Spacing	13m	8m	Better near-wellbore reservoir contact
Perforation Design	6x3	9x2	Better near-wellbore reservoir contact

Enhanced Performance vs. Prior Operator

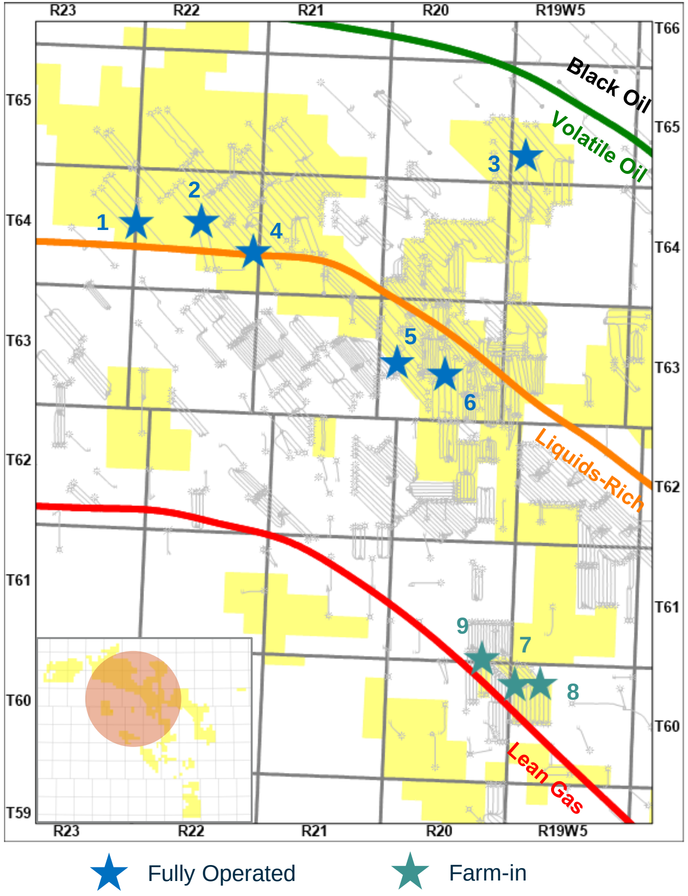




Volatile oil window example normalized to 2-mile lateral length. D&C: drilling and completions.

Kaybob Duvernay Results & Booked EURs – Highlights Condensate Mix

Pad (On Prod)	IP30 boe/d (% Condy, NGLs)	IP90 boe/d (% Condy, NGLs)	Booked EUR mboe (% Condy, NGLs)
Production Results Since Entering the Play (Per Well)			
Fully Operated (100% WI)			
1 (Q1 22)	825 (73%, 7%)	725 (70%, 8%)	670 (62%, 11%)
2 (Q2 22)	900 (71%, 8%)	815 (69%, 8%)	905 (62%, 11%)
3 (Q3 22)	900 (81%, 5%)	785 (80%, 5%)	795 (65%, 10%)
4 (Q3 22)	715 (67%, 9%)	810 (64%, 10%)	805 (57%, 12%)
5 (Q4 22)	950 (50%, 16%)	960 (47%, 16%)	1,400 (32%, 19%)
6 (Q1 23)	1,235 (51%, 15%)	N/A	1,045 (32%, 19%)
Farm-in (50% WI)			
7 (Q4 21)	1,270 (38%, 10%)	1,235 (37%, 10%)	1,955 (21%, 22%)
8 (Q1 22)	1,125 (38%, 10%)	1,325 (35%, 11%)	1,800 (22%, 22%)
9 (Q2 22)	1,195 (32%, 11%)	1,170 (29%, 12%)	1,220 (21%, 22%)



All figures are approximates. EUR: estimated ultimate recovery. Booked EURs based on P+PDP (Probable + Proved Developed Producing).

Public Data Underestimates High Condensate Production Levels

- Condensate volume is publicly reported on a gas-equivalent basis when condensate volumes are recombined with gas at the wellhead (as per the AER and Directive 17)
- The Gas Equivalent Factor (GEF) used in this calculation underestimates the well capability, on a boe/d basis, for high condensate wells

Example

- Pad 2 Average Production Per Well (June 2022)
- GEF = 0.75 mcf/bbl (from gas analysis – range of GEF: 0.65 to 1.15 mcf/bbl)
- 800 bbl/d of condensate = 600 mcf/d of gas when converted using GEF
- 967 boe/d of actual production vs. 267 boe/d being reported

Pad 2	Actual	Public
Condensate (bbl/d)	800	0
Gas (mcf/d)	1,000	1,600
BOE (boe/d)	**967**	**267**
% Liquids	**79%**	**0%**

$$\underbrace{800\ Condensate \times 0.75\ GEF = 600\ Gas}_{1600\ =\ 600\ +\ 1000}$$

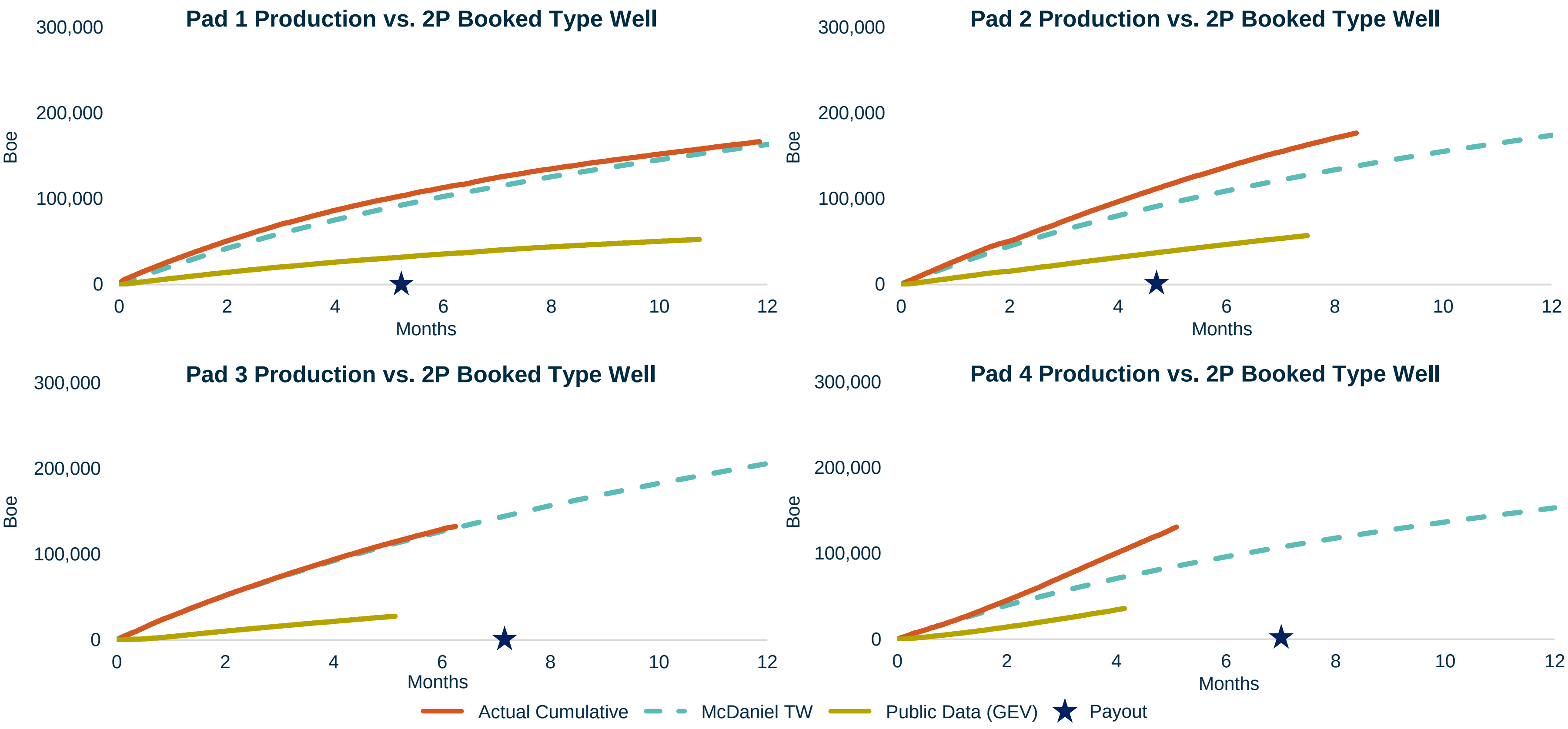
$$\underset{\substack{Reported\\Gas}}{1600} = \underset{\substack{Converted\\Condensate}}{600} + \underset{\substack{Actual\\Gas}}{1000}$$

Pad 2	2P Booked Type Well	Public Data GEV Type Well
Condensate EUR (Mbbl)	557	-
Gas EUR (Mmcf)	1,501	2,304
NGL EUR (Mbbl)	98	-
Total EUR (Mboe)	905	384
Capital ($MM)	$10.5	$10.5
NPV10 ($MM)	$18.8	($8.0)
IRR%	121%	-
PI10	1.82	-
Payout (Months)	6.0	-

Economics based on US$75 WTI and $3.50 AECO. Payout is from initial on-stream date. Pad 2 volumes are based on one month production. GEV: gas equivalent volumes. “Gas” refers to the Shale Gas product type.

Kaybob Duvernay Operated Results – Volatile Oil

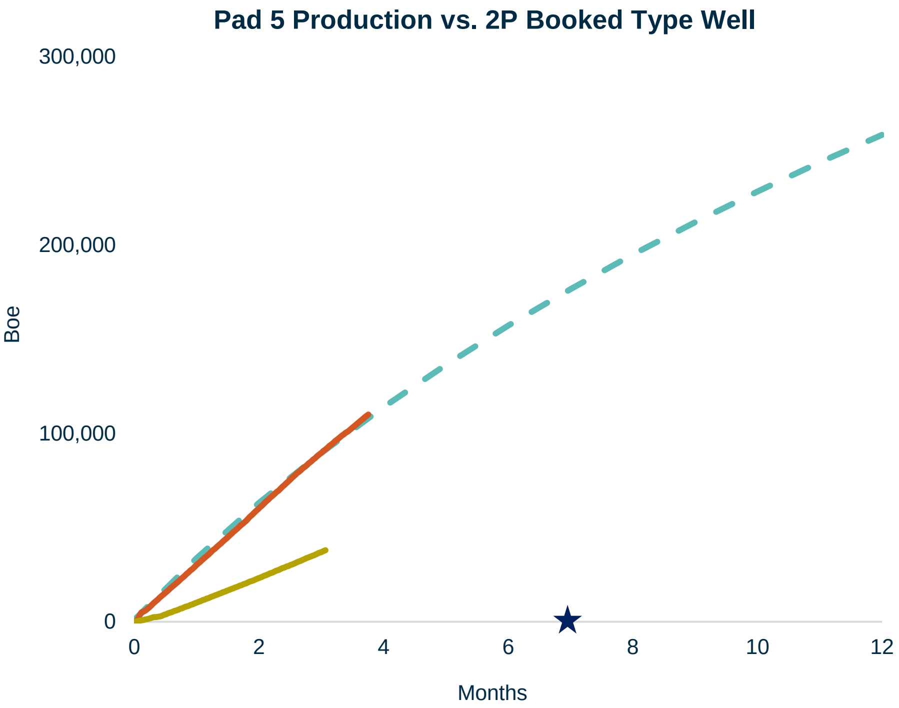
High-return, quick payout wells performing in-line or ahead of booked type well expectations

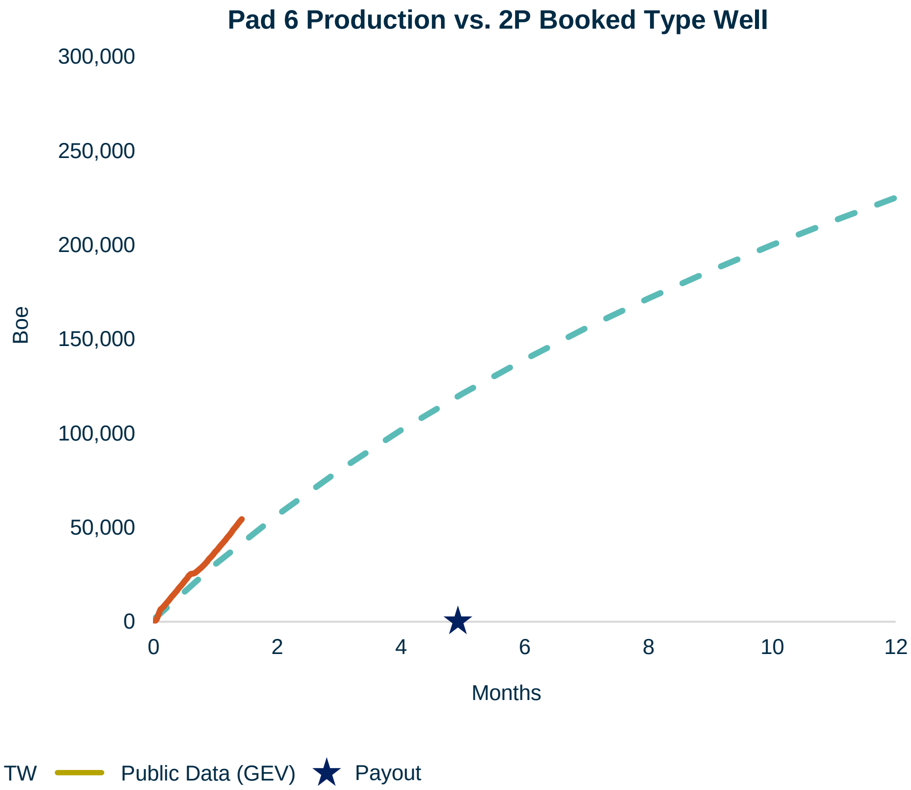


GEV: gas equivalent volumes. TW: type well. Payouts are calculated from the initial onstream date.

Kaybob Duvernay Operated Results – Liquids-Rich

High-return, quick payout wells performing in-line or ahead of booked type well expectations

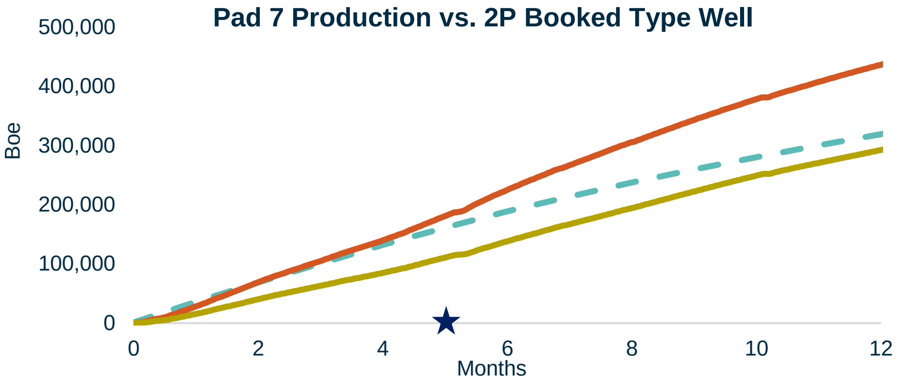


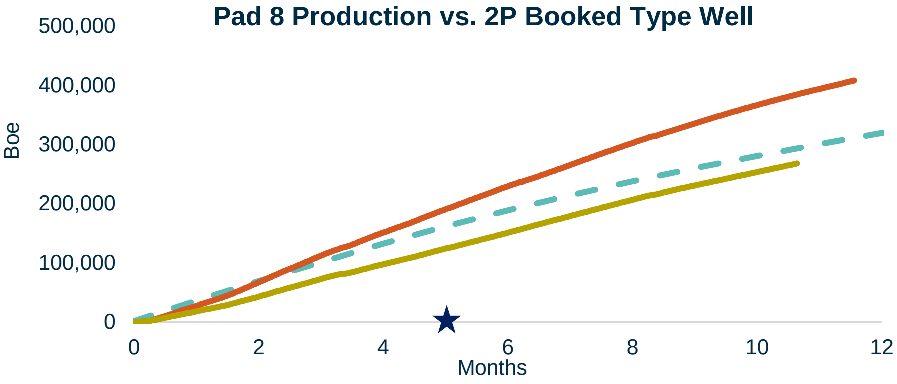


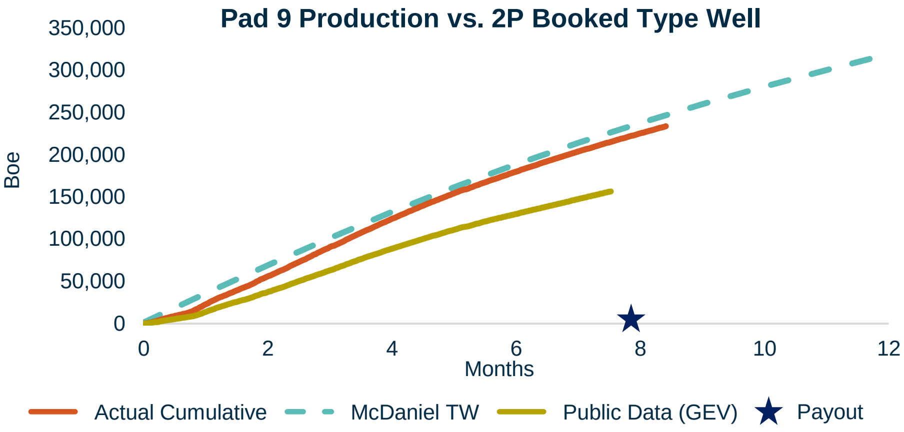
GEV: gas equivalent volumes. TW: type well. Payouts are calculated from the initial onstream date.

Kaybob Duvernay Farm-in Results – Liquids-Rich

High-return, quick payout wells performing in-line or ahead of booked type well expectations



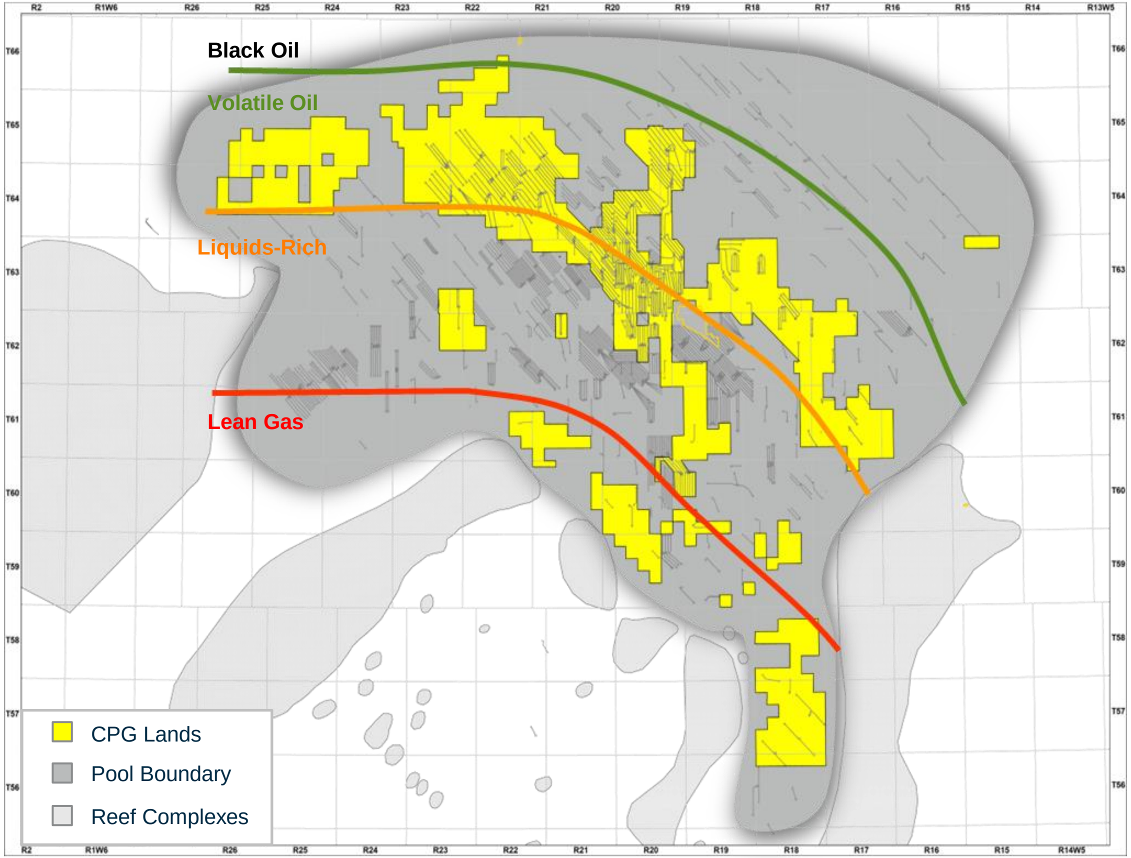




GEV: gas equivalent volumes. TW: type well. Payouts are calculated from the initial onstream date.

Kaybob Duvernay Reservoir Regions & Economics

Kaybob Duvernay returns are top-quartile within the portfolio and underpin the corporate 10-year plan



Volatile Oil	
IP30 (boe/d) (% Liquids)	700 – 1,000 (>75%)
EUR (mboe) (% Liquids)	700 – 1,000 (>65%)
Cost Per Well ($MM)	$10.5
NPV10% ($MM)	$18.0
Payout (Months)	7
IRR%	140%
Net Locations	225

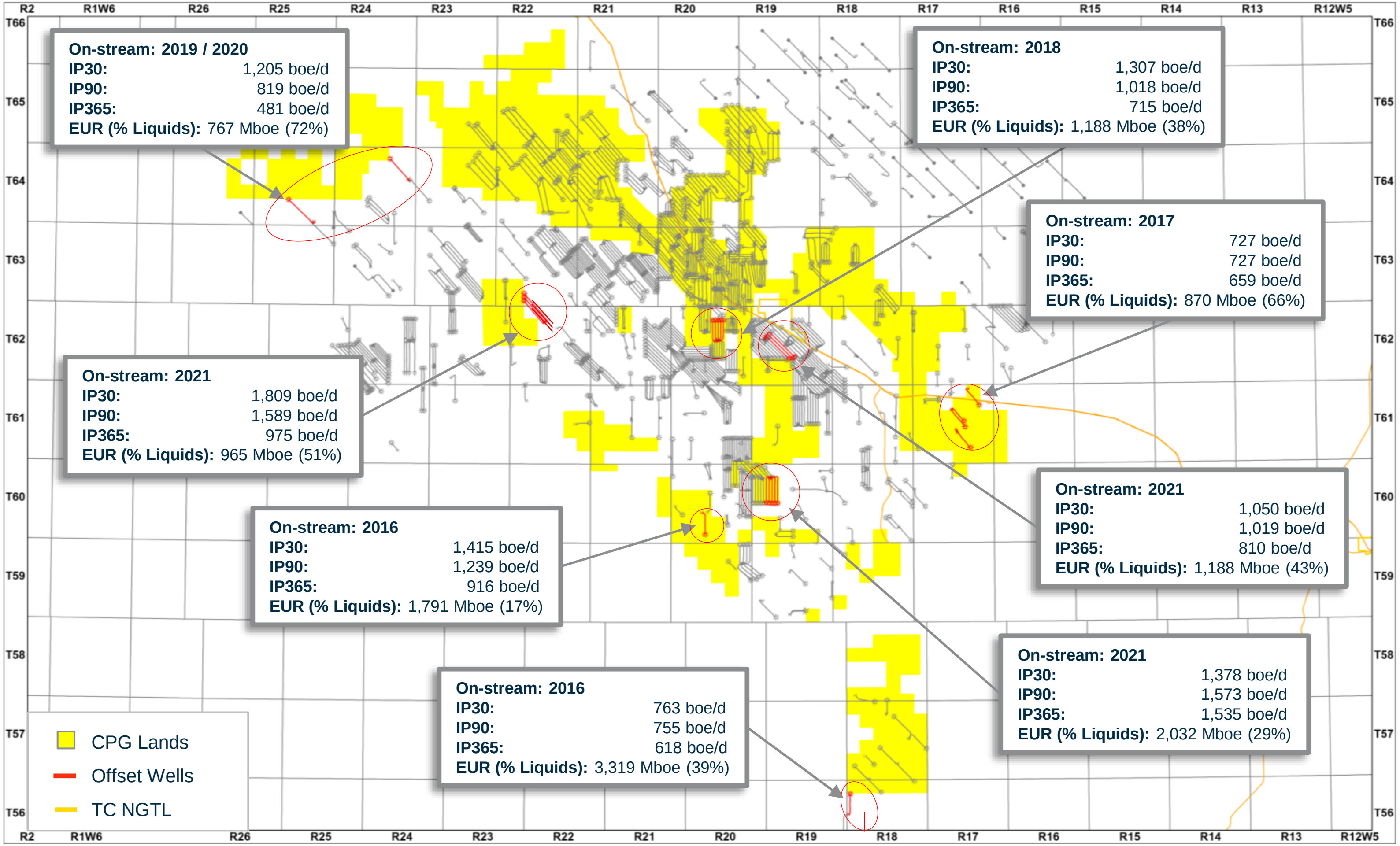
Liquids-Rich	
IP30 (boe/d) (% Liquids)	1,000 – 1,500 (35% – 75%)
EUR (mboe) (% Liquids)	1,000 – 1,500 (35% – 65%)
Cost Per Well ($MM)	$11.0
NPV10% ($MM)	$20.0
Payout (Months)	6
IRR%	160%
Net Locations	125

Lean Gas	
IP30 (boe/d) (% Liquids)	>1,500 (<35%)
EUR (mboe) (% Liquids)	1,500 – 2,000 (<35%)
Cost Per Well ($MM)	$11.5
NPV10% ($MM)	$12.0
Payout (Months)	12
IRR%	75%
Net Locations	150

NPV10 and payout as at US$75/bbl WTI and $3.50/mcf AECO, assuming the mid-point of estimated ultimate recovery (EUR) ranges. Payouts are calculated from the initial onstream date.
Internally identified inventory of 500 net locations includes 126 booked 2P locations.

CRESCENT POINT | CORPORATE PRESENTATION

Strong Industry Results Offsetting CPG's Undeveloped Land Position



Source: Accumap, Geoscout and CPG data.

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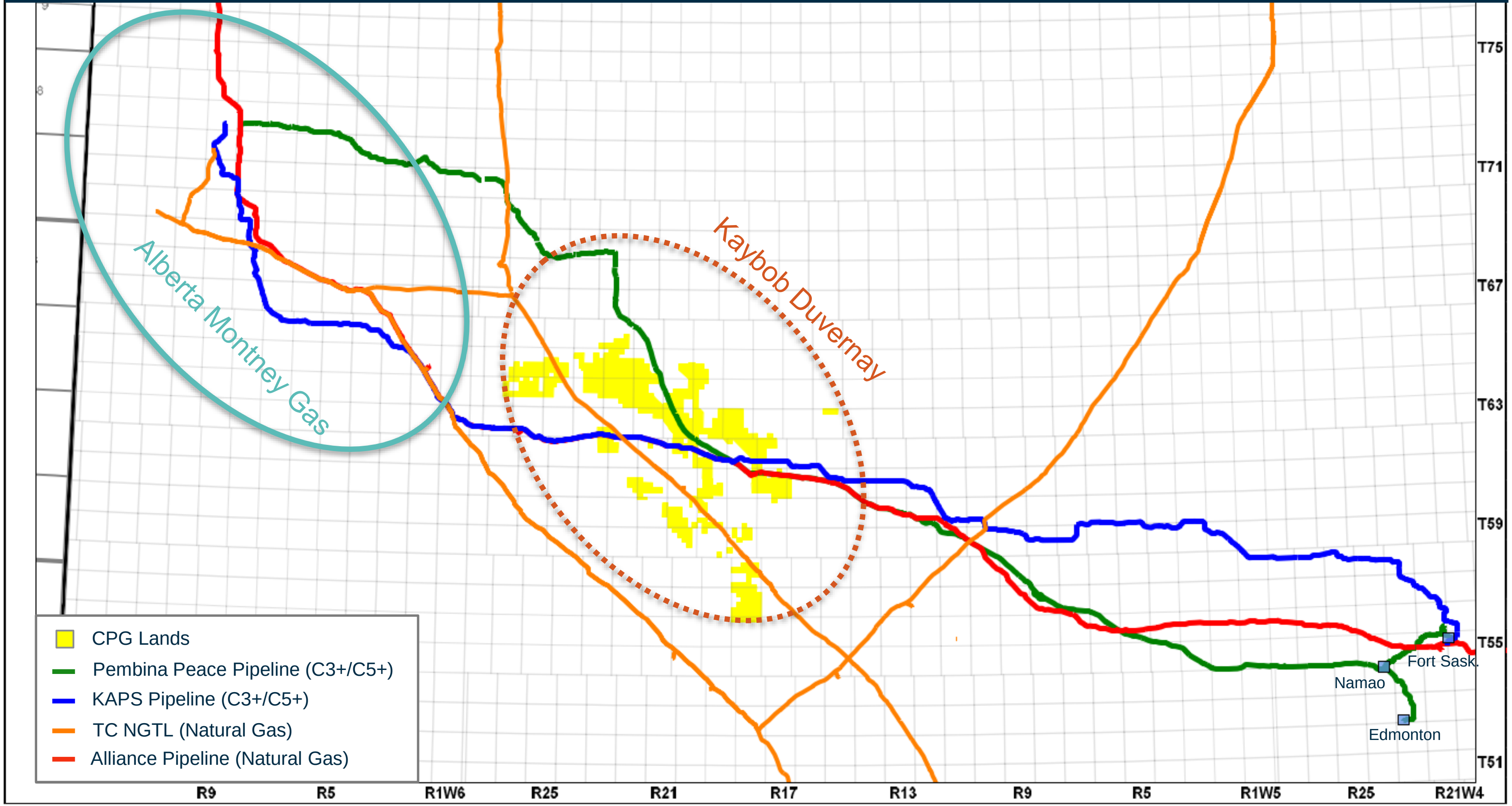
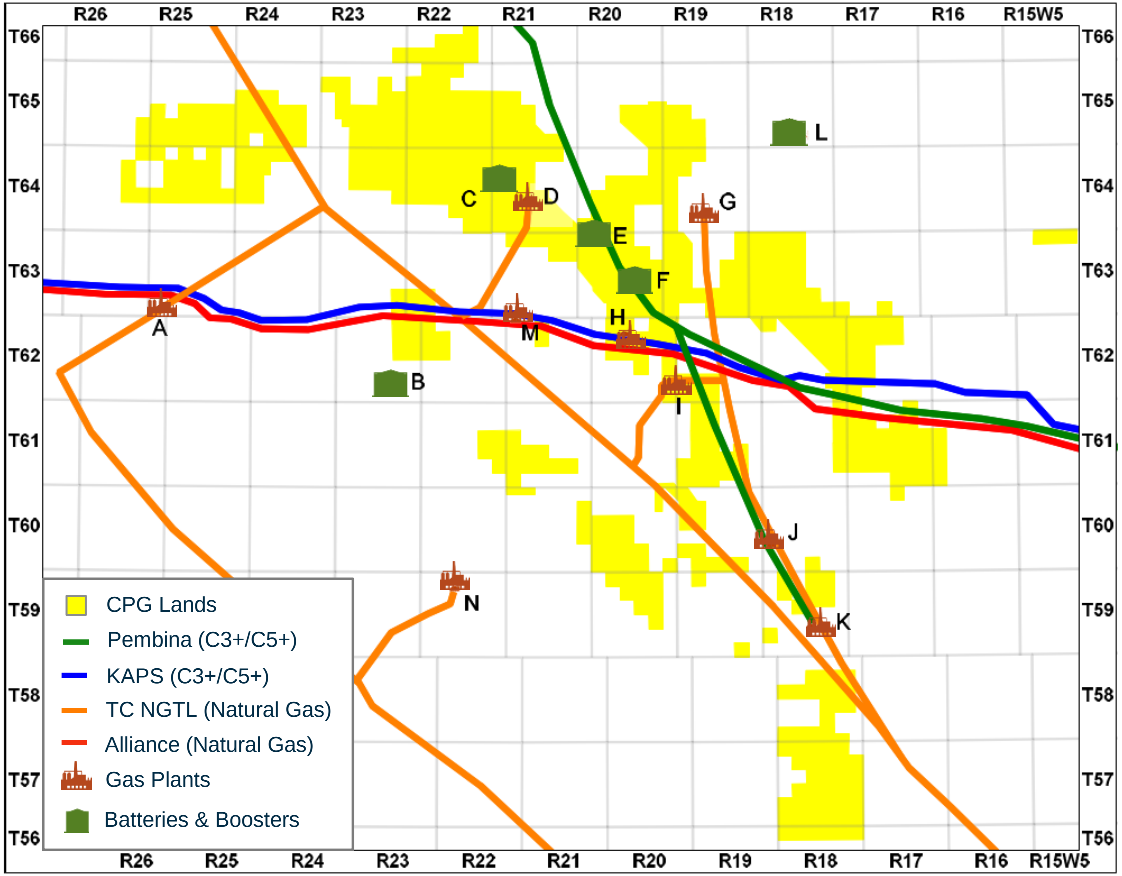
Kaybob Duvernay Geographical & Market Access Advantage

Kaybob Duvernay is downstream of Montney and is very well connected to all major product lines



Kaybob Area Well Established Infrastructure & Egress

Numerous large facilities in place and well connected to major gas and liquids transportation lines

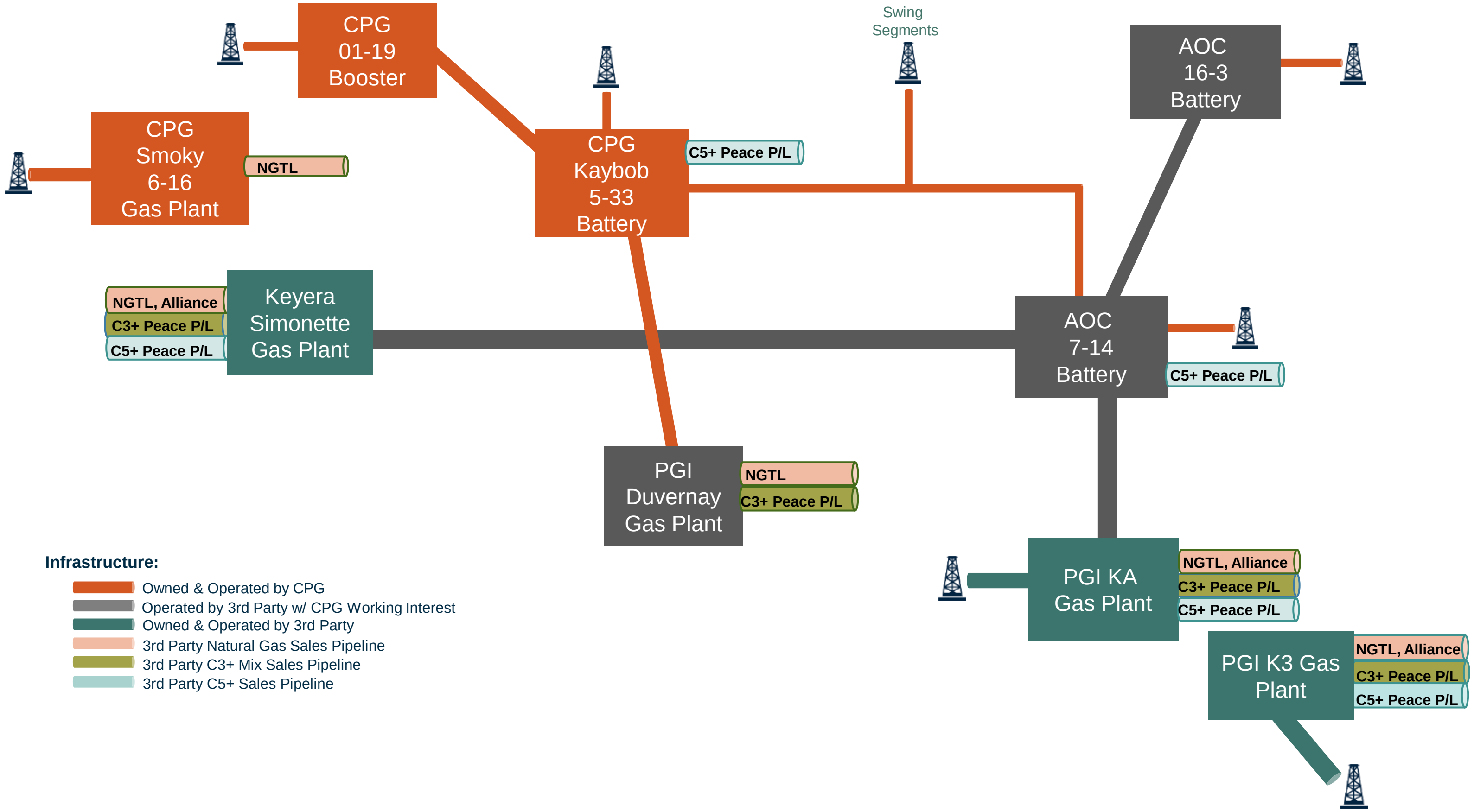


- Access to major liquids pipelines from all major processing facilities
- All major gas plants are connected to Nova Gas Transmission Line (NGTL) system, Alliance Pipeline or both
- Firm transportation service held to support long term plans for liquids and natural gas

Major Facilities	
A	09-06 Keyera Simonette Gas Plant
B	10-19 AOC Saxon Battery
C	01-19 CPG Booster
D	06-16 CPG Smoky River Gas Plant
E	05-33 CPG Battery
F	07-14 AOC Battery
G	08-09 Paramount Kaybob Gas Plant
H	14-28 PGI Duvernay Gas Plant
I	01-12 PGI Kaybob Amalgamated Gas Plant (KA)
J	15-07 Whitecap Gas Plant
K	03-15 PGI Kaybob South Gas Plant (K3)
L	16-03 AOC Battery
M	15-31 PetroChina Duvernay Gas Plant
N	14-28 Repsol Bigstone Gas Plant

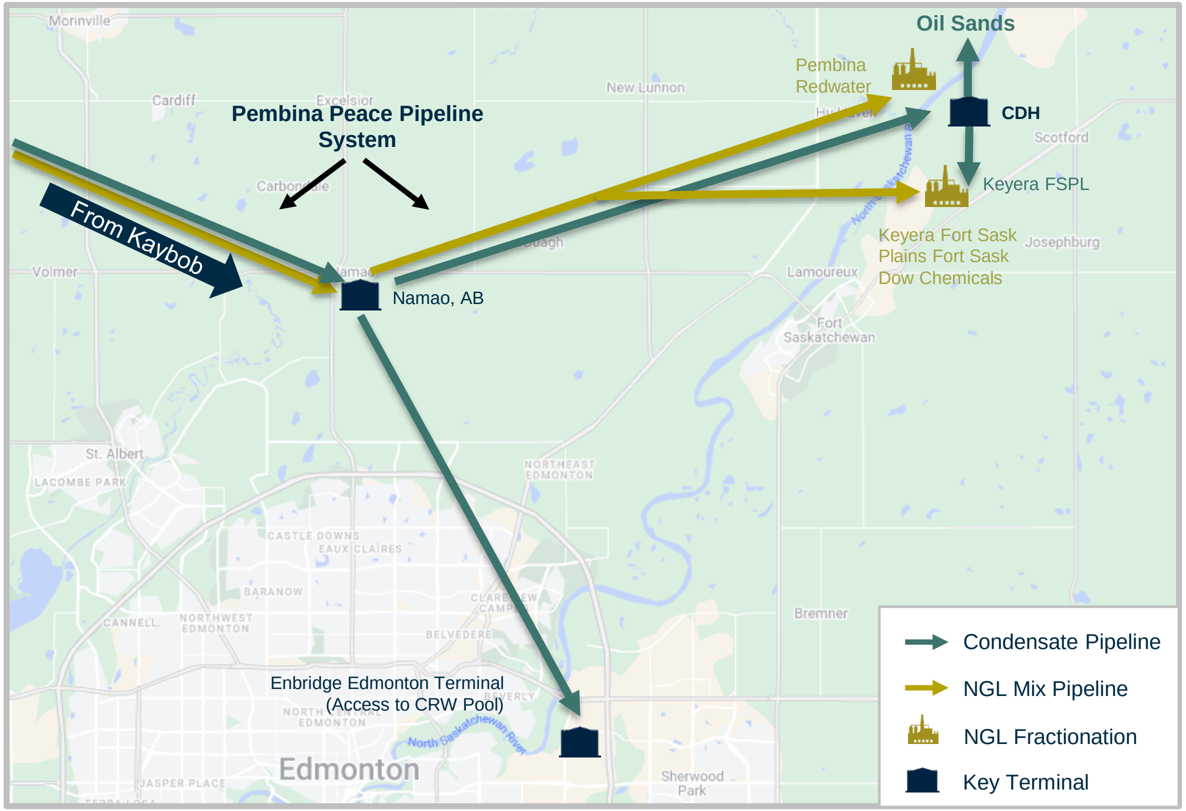
Kaybob Duvernay Infield Infrastructure

Significant CPG ownership and egress in place



Kaybob Liquids Egress are Well Connected to Key Markets

Condensate is directly connected to the oil sands while other liquids flow directly to major fractionation plants



Condensate (C5)

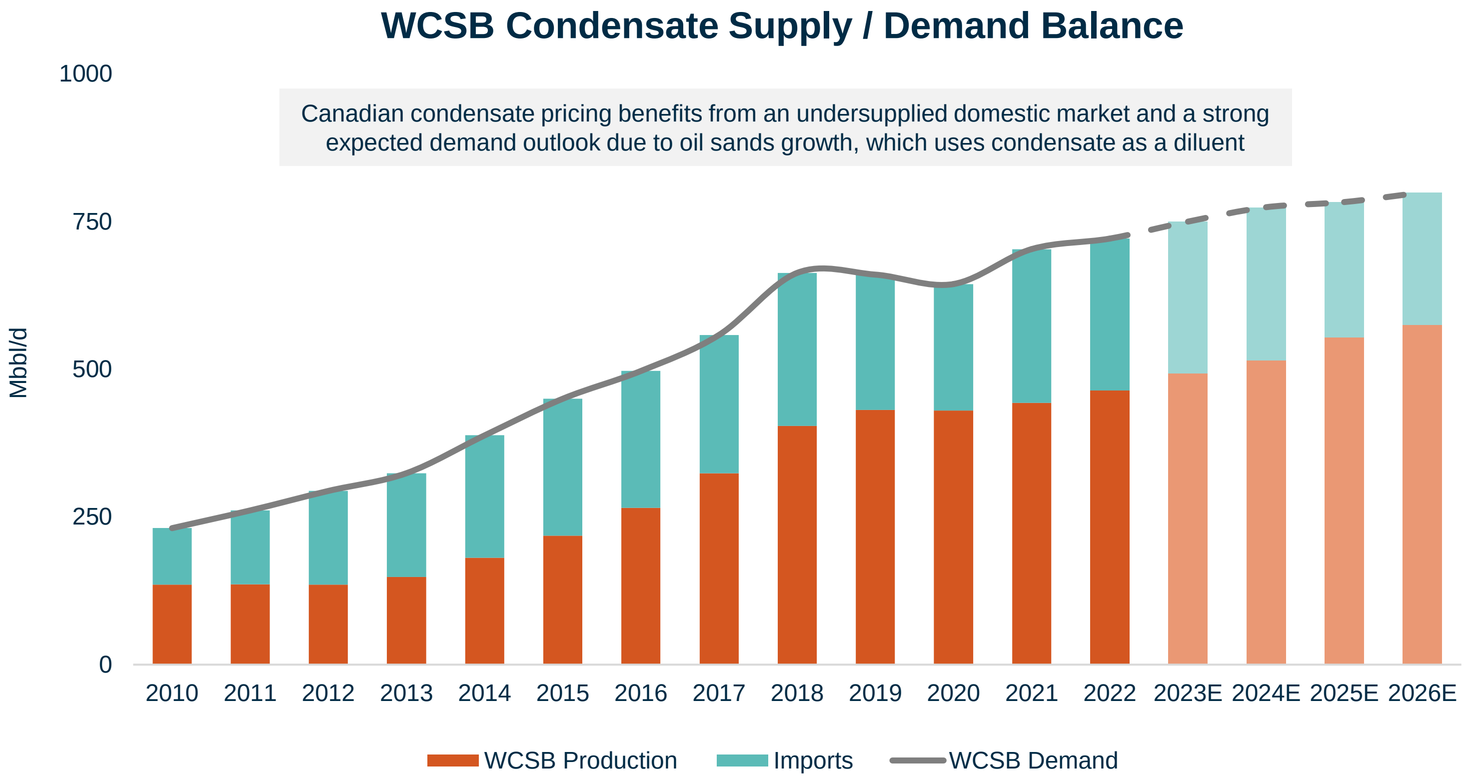
- Flows on the Peace Pipeline System to Namao, AB
- From Namao, AB optionality to access the Enbridge Edmonton Terminal or the Canadian Diluent Hub (CDH) near Fort Saskatchewan
- From CDH, can access Fort Saskatchewan and pipelines to oil sands diluent buyers

C3+ NGL Mix

- Flows on the Peace Pipelines System where it can access Fort Saskatchewan and Redwater Fractionators
- Keyera, Pembina, Dow and Plains operate major fractionation plants representing ~344kbpd of capacity
- CPG holds firm fractionation capacity to support growth plans

Significant Condensate Exposure with a Strong Supply / Demand Outlook

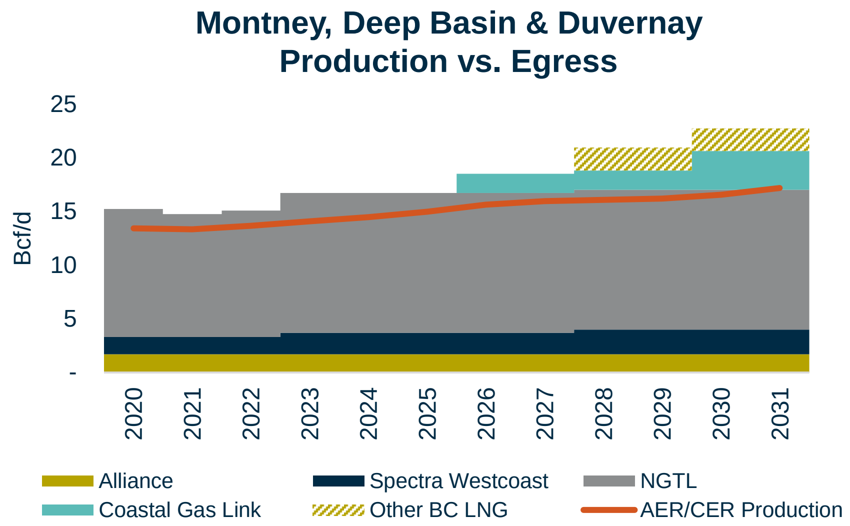
~20% of CPG's 2023E liquids production is condensate and receives strong pricing relative to WTI

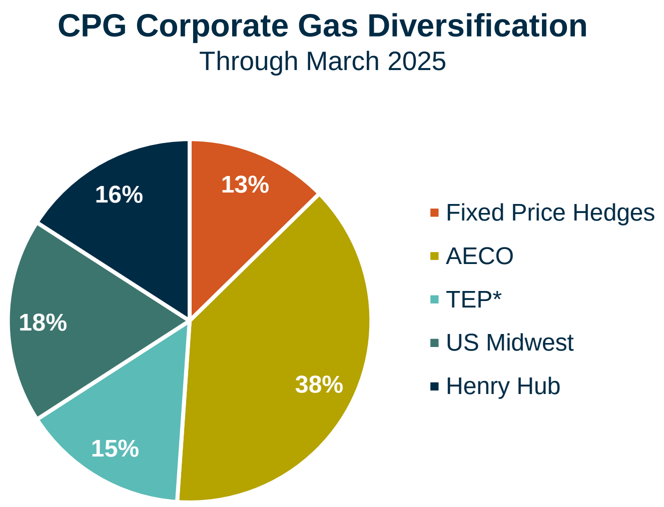


Source: Peters & Co. Equity Research.

WCSB Natural Gas Egress & CPG Diversification

CPG's strong gas market diversification is further enhanced by a positive egress outlook for WCSB natural gas



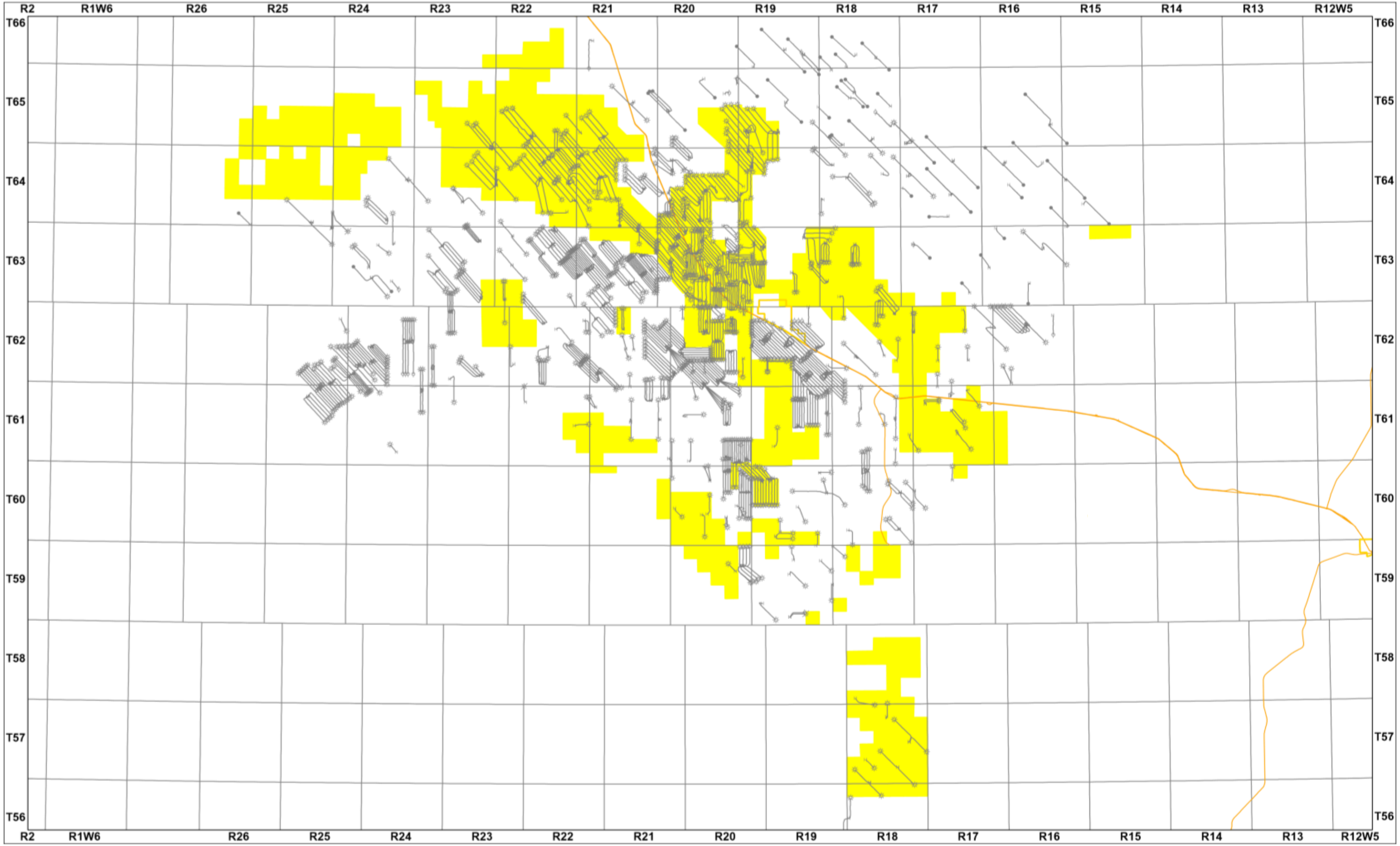


- Coastal Gas Link/LNG Canada are expected to come online by 2025 providing an outlet for WCSB natural gas growth
- Other probable LNG projects provide further line of site to long term growth

- CPG has diversified its natural gas price exposure through a combination of physical and financial transactions, along with natural geographical diversification
- Continue to evaluate other opportunities to further diversify our gas sales portfolio

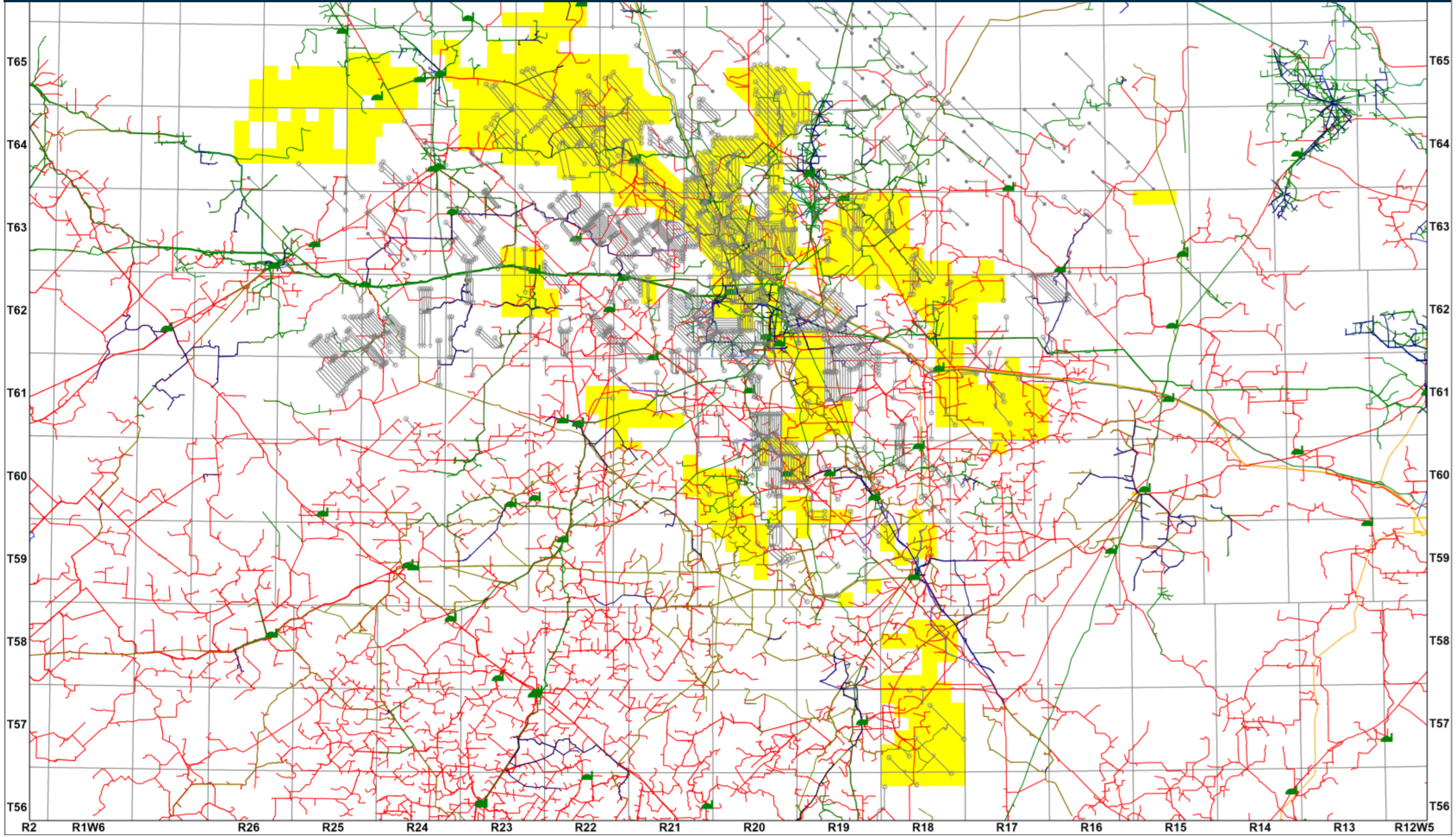
*TEP – Saskatchewan hub trades at a premium to AECO – current contract year premium >$0.40/GJ.
Production vs egress source: public and internal data. AER/CER: Alberta Energy Regulator / Canadian Energy Regulator.

Crescent Point Energy Infrastructure – Kaybob Duvernay Land Position



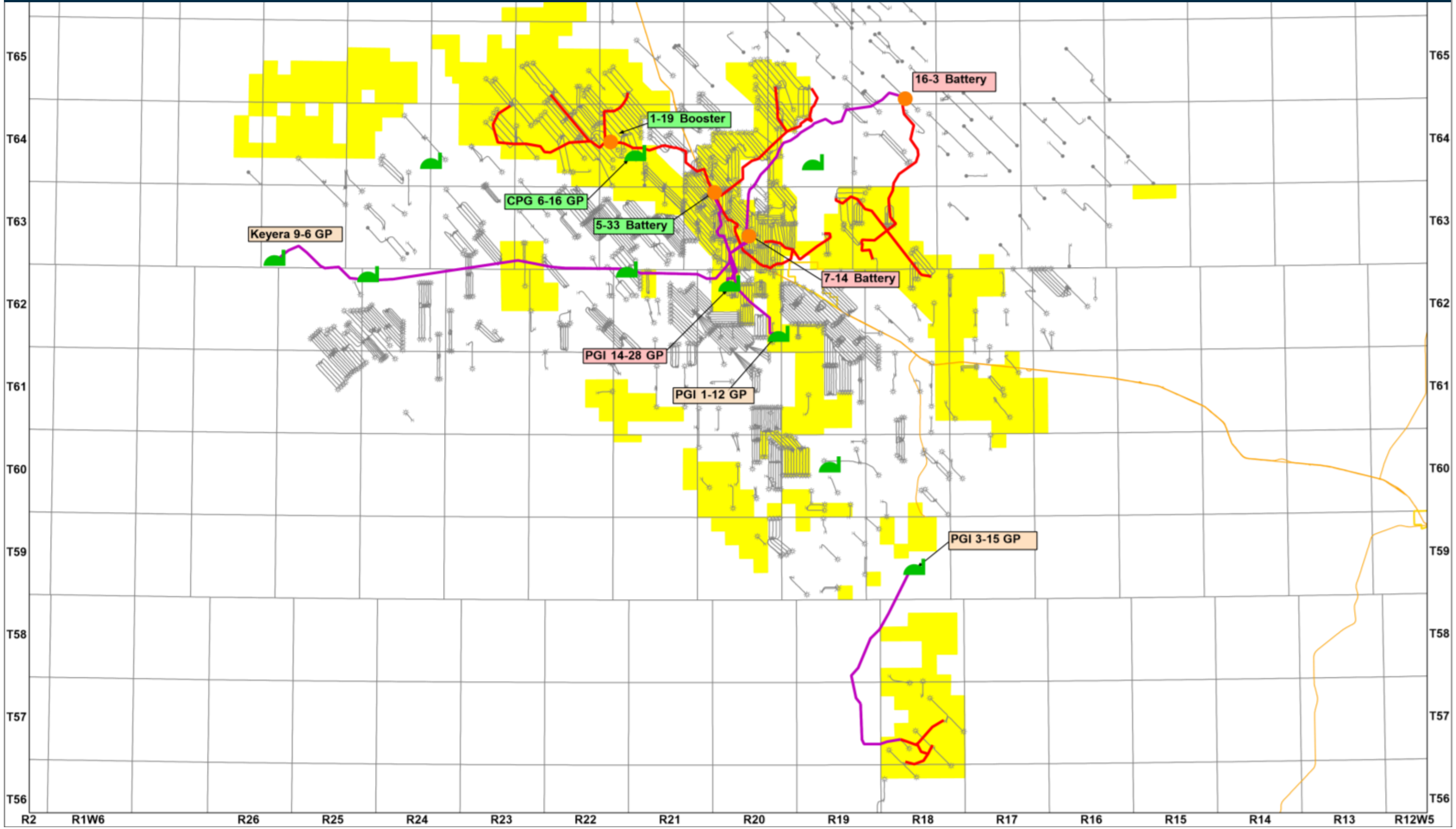
Kaybob Area – All Pipelines & Gas Plants

Very significant Kaybob Duvernay and non-Duvernay infrastructure already in place



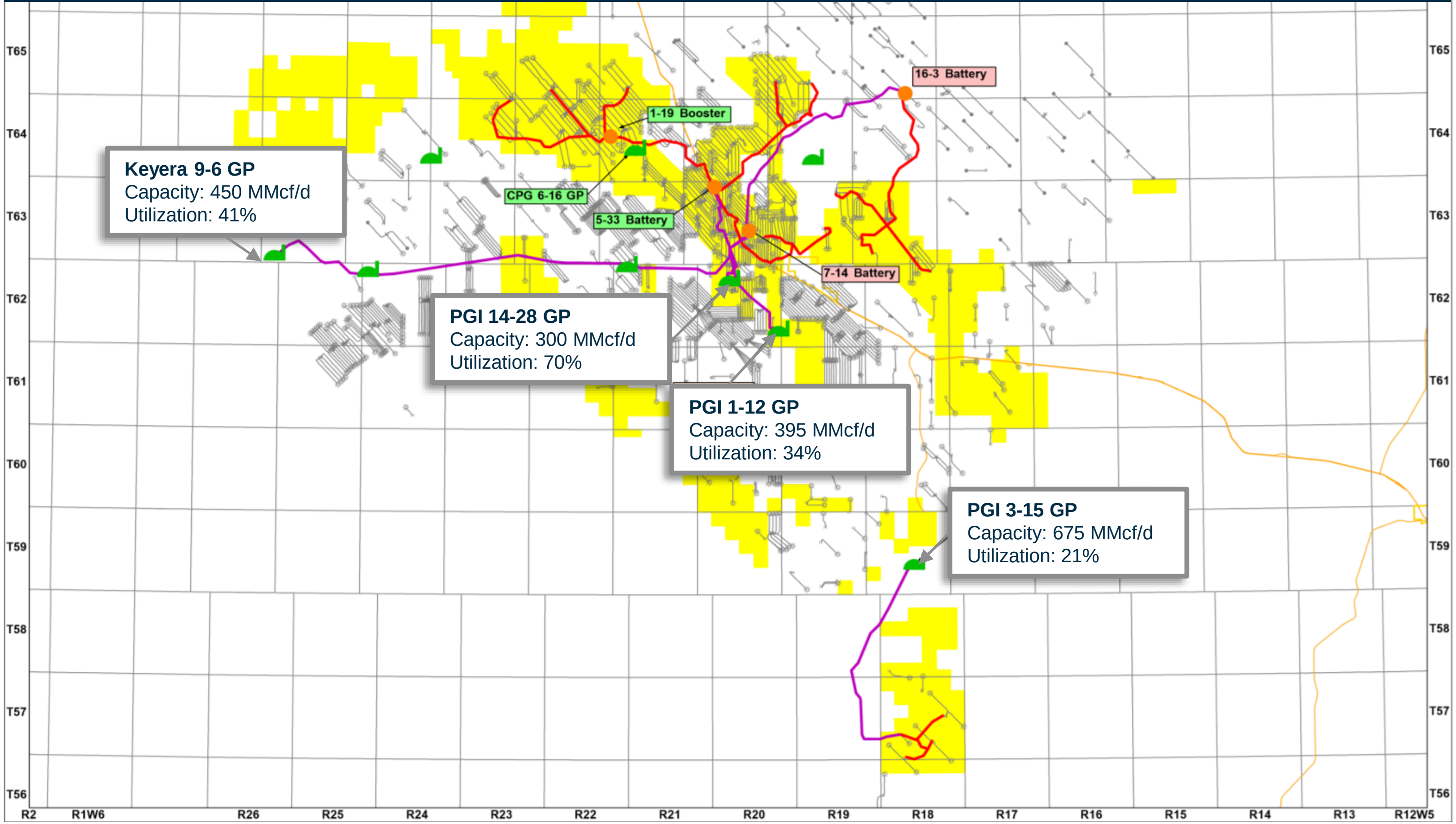
Crescent Point Energy – Kaybob Duvernay – Current Infrastructure

Kaybob Duvernay CPG owned and major third-party infrastructure already in place



Crescent Point Energy – Kaybob Duvernay – Gas Plant Utilization

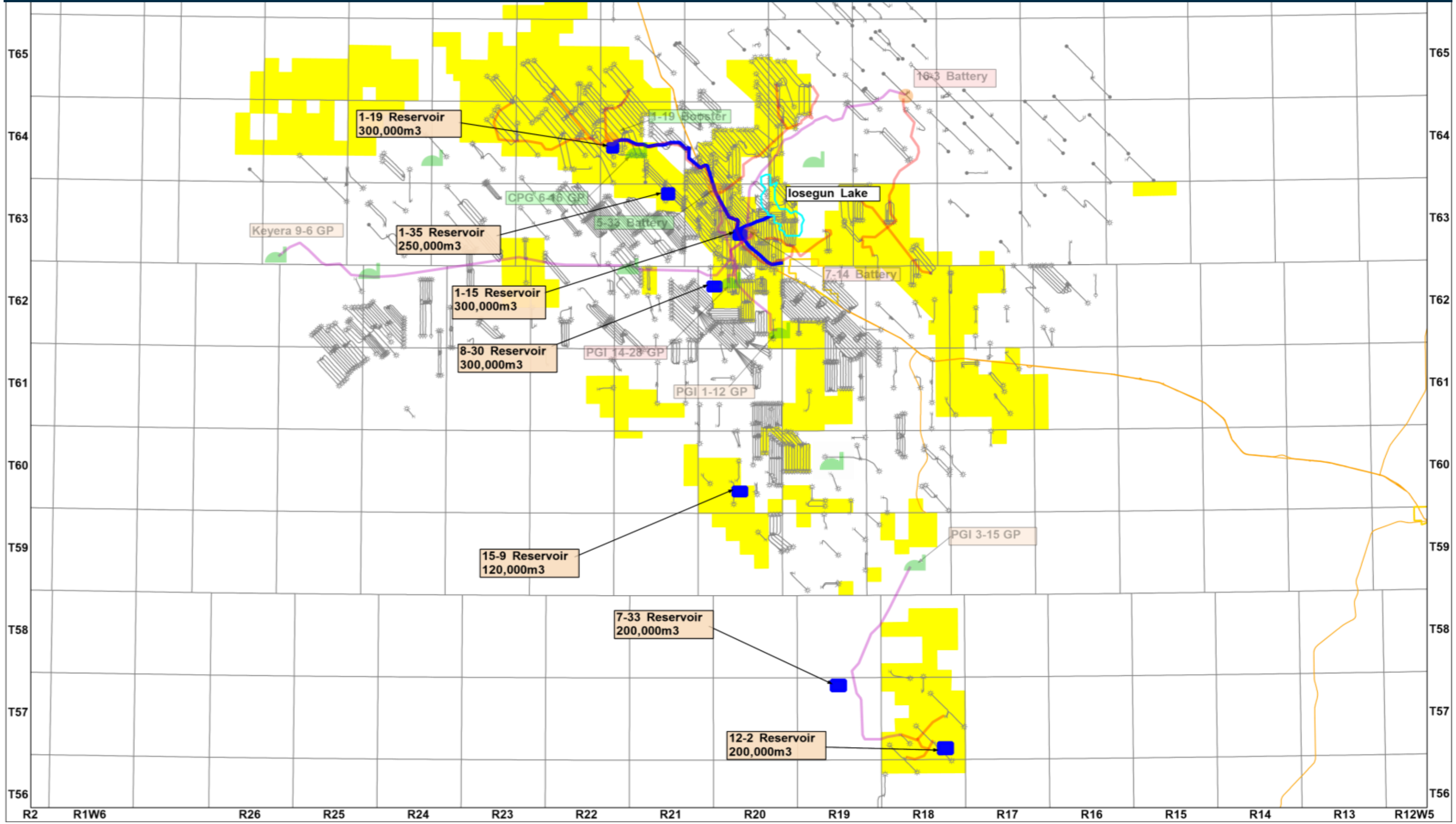
Significant gas processing capacity available throughout the basin (~55% unutilized)



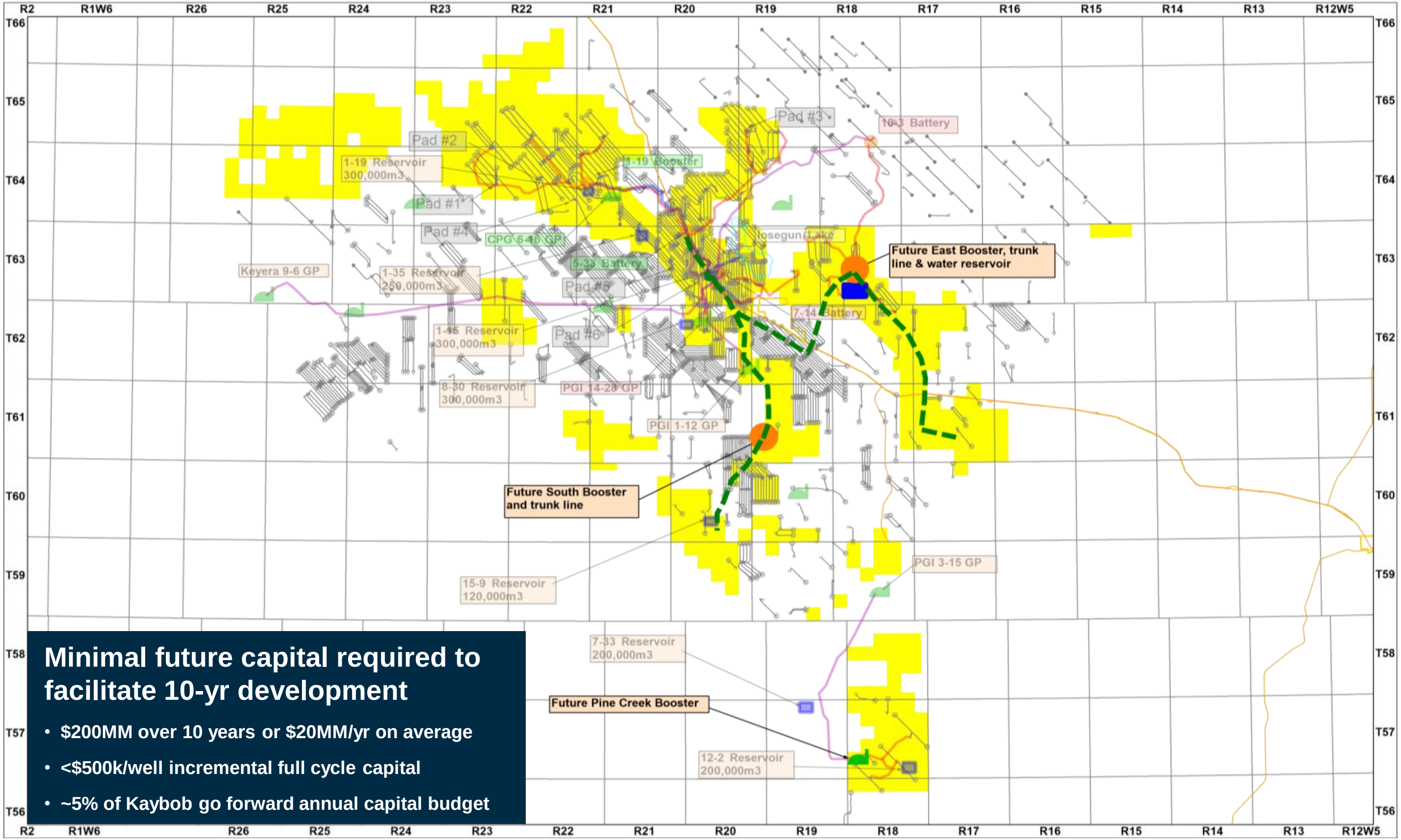
Source: public data.

Crescent Point Energy – Kaybob Duvernay – Water Infrastructure

CPG has significant water storage across the field of >1,700,000 m³ already in place



Crescent Point Energy – Kaybob Duvernay – Future Infrastructure



Minimal future capital required to facilitate 10-yr development

- $200MM over 10 years or $20MM/yr on average
- <$500k/well incremental full cycle capital
- ~5% of Kaybob go forward annual capital budget

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Solid Corporate Inventory Drives Long-Term Sustainability

Solid 10-year plan which has been enhanced through addition of Kaybob Duvernay assets

Excess Cash Flow & Long-Term Growth

Alberta (Kaybob Duvernay)

- **Long-term sustainability (10-year plan)**
- **Top-quartile returns**
- **Additional Upside:**
  - Enhanced efficiencies
  - Unbooked reserves growth
  - Down-spacing & step-out drilling

Excess Cash Flow & Low-Decline Stable Production

Saskatchewan (Various Plays)

- **Long-term sustainability (10-year plan)**
- **High-return projects focused on infill drilling and decline mitigation**
- **Additional Upside:**
  - Further decline mitigation
  - Step-out drilling
  - Advancing new technology / D&C practices

Excess Cash Flow & Near-Term Growth

North Dakota (Bakken)

- **Near-term development (5-year plan)**
- **Competitive returns driven by highly productive wells**
- **Additional Upside:**
  - Developing Three Forks locations

Saskatchewan includes Viewfield Bakken, Flat Lake, Shaunavon and other conventional assets. D&C: drilling and completions.

Kaybob Duvernay Provides A Combination of Excess Cash Flow & Growth

Kaybob's attractive netbacks are driven by its high-margin condensate mix and low-cost structure

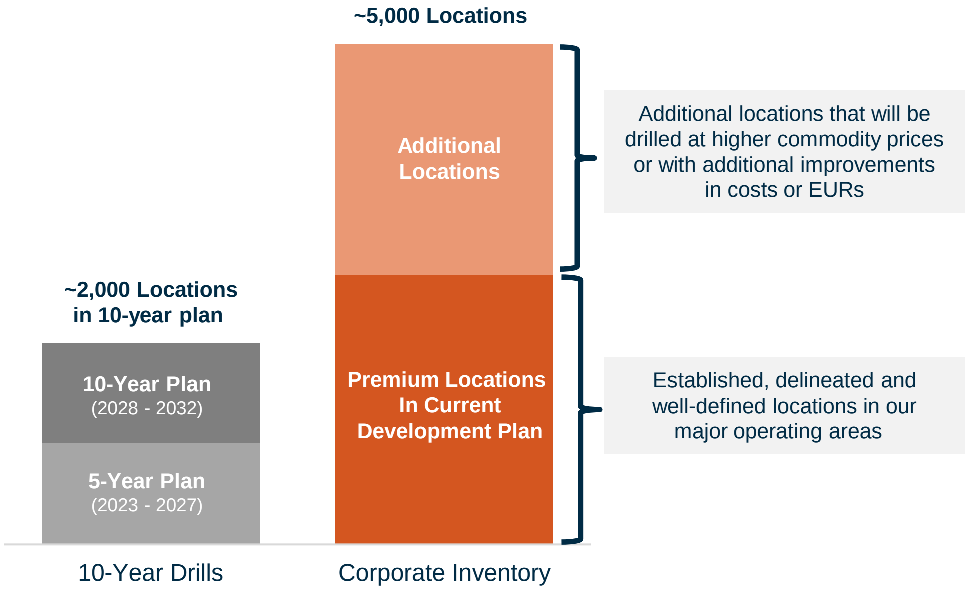
2023 Metrics	Kaybob Duvernay	Viewfield Bakken & Flat Lake	Shaunavon	North Dakota
Average Production (boe/d)	**~45,000**	~40,000	~20,000	~30,000
% Liquids	**55%**	>90%	>90%	90%
Pricing Stream	**C5**	LSB	FOS	UHC
Royalty (%)	**9%**	10-12%	10-12%	27%
Operating Expenses ($/boe)	**$6.50**	$21.00	$19.25	US$8.25
Operating Netback ($/boe)	**$43.50**	$50.00	$42.00	US$34.00
FCF (% of Corp.)	**33%**	42%	17%	7%
Base Decline Rate	**30%**	20%	20%	30%

All figures are approximates and are based on midpoint of 2023 guidance, US$75/bbl WTI and $3.50/mcf AECO. Shaunavon includes Battrum (conventional).
FCF is net operating income (NOI) less capital expenditures. FOS: Fosterton, LSB: Light Sour Blend, UHC: Sweet at Clearbrook, C5: Condensate. North Dakota royalty % includes severance tax.
Operating netback is a specified financial measure - refer to the Specified Financial Measures section. Average production from other assets is ~5,000 boe/d in 2023.

Highly Economic Long-Term Development Plan

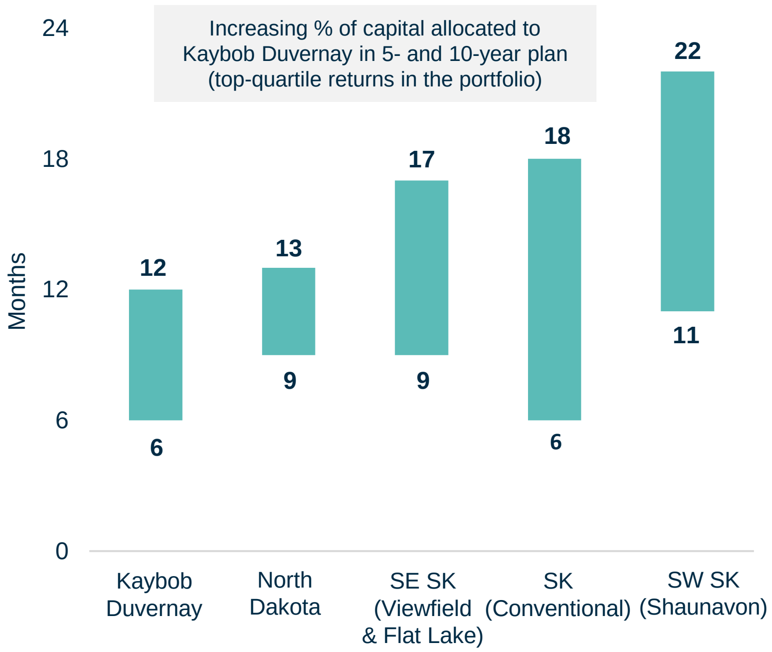
Strong corporate inventory supports a highly economic and long-term development plan

Corporate Inventory vs 10-Year Plan



Economics of Premium Locations

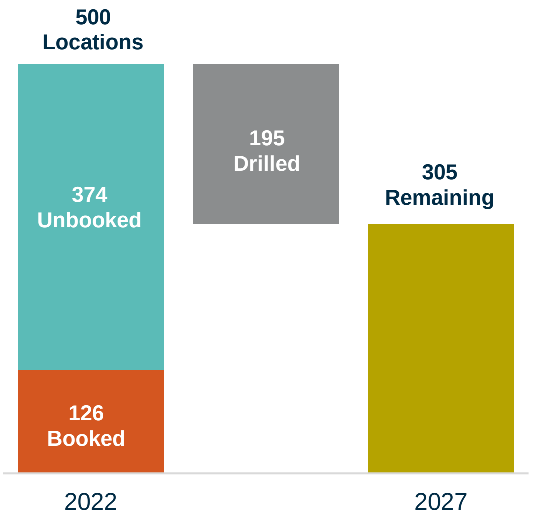
(Well Payout – US$75 WTI)



Inventory locations presented above are net and include 1,555 booked 2P locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook. Payouts are calculated from the initial onstream date. Economics assume $3.50/mcf AECO.

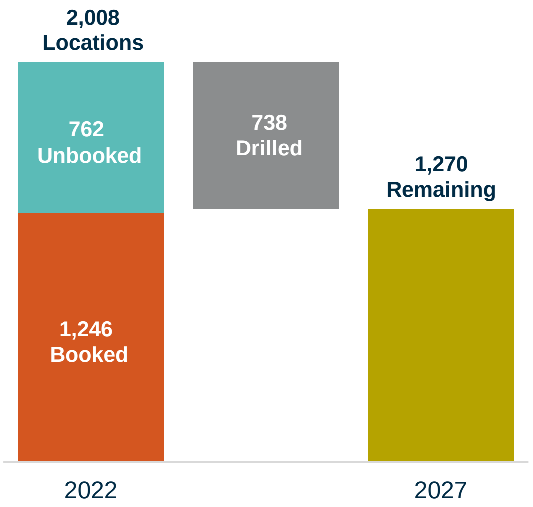
Premium Locations by Major Operating Area & 5-Year Development Plan

Kaybob Duvernay



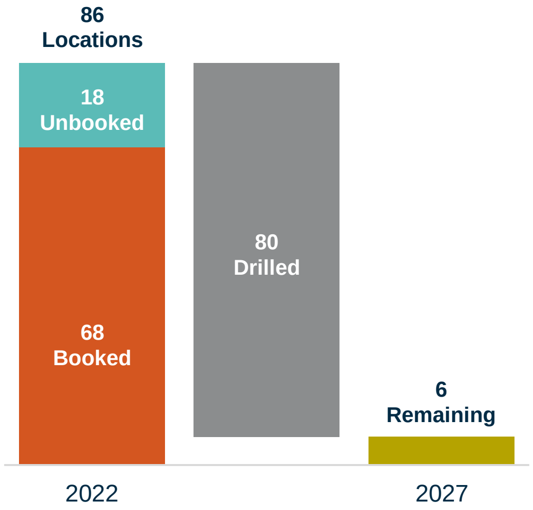
	2023E	2027E
Production	45,000	70,000
FCF (% of Corp.)	33%	45%

Saskatchewan



	2023E	2027E
Production	60,000	60,000
FCF (% of Corp.)	59%	40%

North Dakota

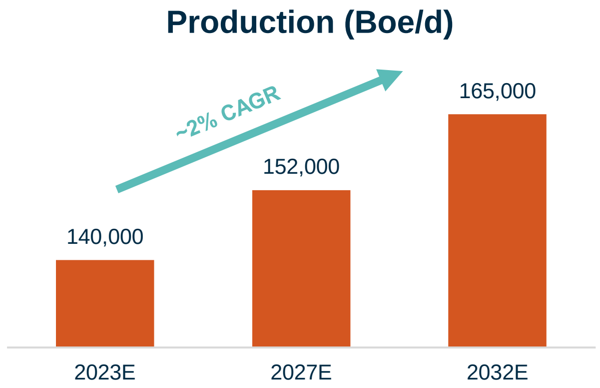


	2023E	2027E
Production	30,000	18,000
FCF (% of Corp.)	7%	15%

Figures above are approximates. FCF is NOI less capex at US$75 WTI. Figures presented above do not include production, FCF or net locations in other areas within the portfolio.
Booked locations are proved and probable locations, as derived from the Company's internal reserves evaluation in accordance with NI51-101 and the COGE Handbook.

5 & 10-Year Outlooks (2023 – 2032)

5-year plan generates $3.0 - $5.8B of cumulative excess cash flow, which more than doubles in 10-year plan



Average per Year (US$75 WTI)	2023-2027	2028-2032
Capital Expenditures ($MM)	$1,100	$950
Reinvestment Ratio	53%	47%
Net Cash ($MM) (Period End)	$240	$2,200
Decline Rate (%)	26%	26%
Cumulative Excess CF ($B)	$4.4	$4.9

5-Year Plan
(2023 - 2027)

$3.0 - $5.8B
of cumulative after-tax **excess cash flow**
or
$5.55 - $10.61 per share
(US$65 – US$85 WTI)

10-Year Plan
(2023 - 2032)

$6.5 - $12.0B
of cumulative after-tax **excess cash flow**
or
$11.84 - $21.97 per share
(US$65 – US$85 WTI)

Capital expenditures refers to development capital expenditures.
Reinvestment ratio, D/CF and cumulative excess CF figures are based on AECO of $3.50/Mcf in 2023-2032. Reinvestment ratio is defined as capex as a % of cash flow.
Budgets and forecast beyond 2023 have not been finalized and are subject to a variety of factors including prior year's results. Cumulative excess cash flow per-share based on current shares outstanding.

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Balance Sheet Strength & Long-Term Sustainability Drive Shareholder Returns

- Our strategy to create value for our shareholders is centered around our **key pillars of balance sheet strength and sustainability**
- **Balance sheet strength is essential in a cyclical business** and allows us to execute our business plan through commodity cycles while also providing the ability to **return significant capital to shareholders**
- **Sustainability starts with a resilient asset portfolio** and is further enhanced by our technical ability and willingness to optimize the business
- **Our long-term focus ensures we manage the business in a disciplined manner**

Creating Shareholder Value in a Strategic & Disciplined Manner

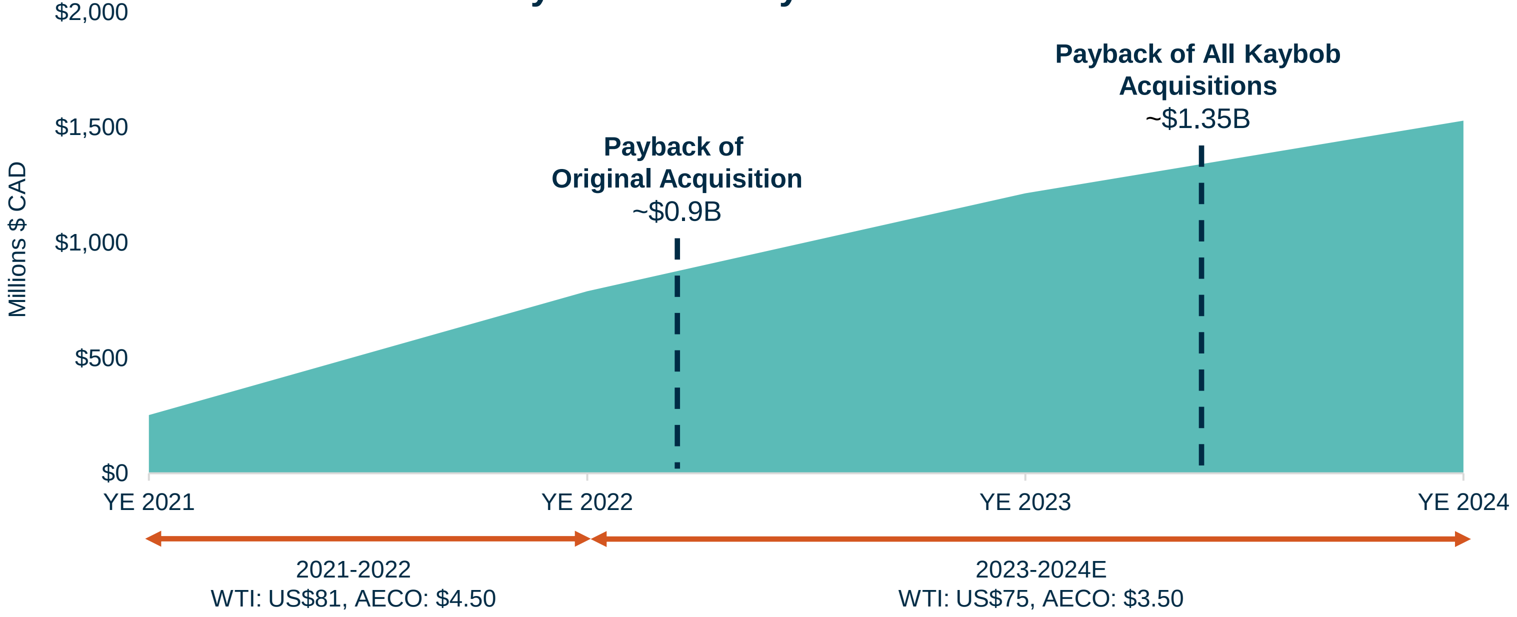
Kaybob Duvernay is a prime example of how CPG's strategy creates value for shareholders

1. **Identified Kaybob Duvernay as a new core area based on set criteria:**
   - ✓ High quality rock (geological and technical analysis)
   - ✓ Returns, scalability, excess cash flow generation, strong market access and ESG factors
   - ✓ Our ability to transfer knowledge from other basins to further enhance value
2. **Executed acquisition that was accretive both financially and to the overall portfolio**
3. **Further optimized portfolio and balance sheet strength through non-core dispositions**
4. **Opportunistically expanded in the play after gaining additional knowledge of the asset and executing operationally**
5. **Developing the asset in a disciplined manner with a continued focus on new efficiencies and improved productivity**

Two-Year Payback on Original Kaybob Duvernay Acquisition

- Kaybob Duvernay asset provides a **combination of organic growth** and **significant excess cash flow generation** driven by its high netback
- **Achieved a two-year payback on the original Kaybob acquisition** in Q1 2023 (~$900MM)
  - Remaining bolt-on acquisitions expected to be paid back in 2024

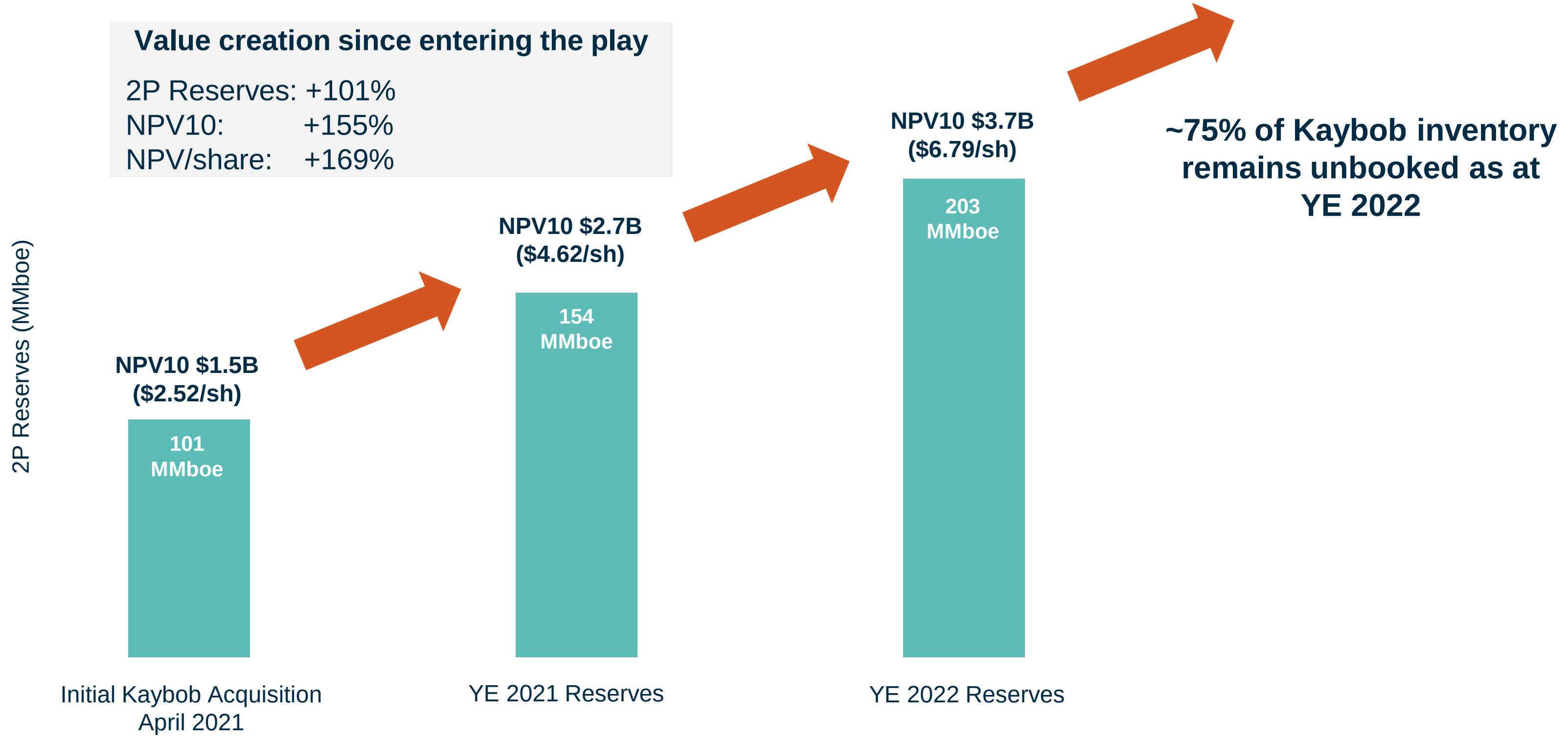
Kaybob Duvernay Free Cash Flow



Free cash flow is NOI (net operating income) less capital expenditures. Two-year payback on the original Kaybob acquisition assumes US$75 WTI and $3.50 AECO for Q1 2023.

Kaybob Duvernay Has Created Significant Value, With More Still to Come

Created value on per-share basis through organic reserves additions, realized efficiencies & opportunistic acquisitions



NPV10 values based on independent engineers reserves and price forecasts. Per share values based on fully diluted shares outstanding at closing of the acquisition in April 2021 and at year-end.
YE 2022 reserves include 126 booked locations 2P basis and excludes recent acquisition that closed in January 2023.

Summary

Executing a disciplined corporate strategy to create long-term shareholder value

- Focused on balance sheet strength and sustainability and a defined asset criteria in place for portfolio optimization

CPG's operational excellence has enhanced overall returns in the play with industry-leading results

- Kaybob drives the company's long-term plan, which includes \$3.0 – \$5.8B of cumulative excess CF over the next 5 years

Kaybob Duvernay is a high-return, condensate-rich play that provides a combination of growth & excess CF

- Major infrastructure and market access already in place to support CPG's disciplined growth strategy

Cumulative excess cash flow (CF) based on a forecast of US\$65 to \$85 WTI.

Q&A

Bringing Energy To Our World – The Right Way

Appendix

Capital Markets Summary & Guidance

Capital Markets Summary
CPG (TSX and NYSE)

Trading Price (Mar. 10, 2023)	C$9.34 (TSX), US$6.75 (NYSE)
Shares Outstanding	547.1 million
Avg. Daily Trading Volume	13.6 million
Dividend Yield	4.3%
Market Capitalization	$5.1 billion
Net Debt	$1.5 billion

Net debt as at acquisition close on Jan. 11, 2023.
Divided yield is based on first quarter 2023 base dividend that equates to $0.40 per share per annum

2023 Guidance

Annual Avg. Production (mboe/d)(1)	138 – 142
Capital Expenditures	
Development Capital Expenditures ($MM)	$1,000 - $1,100
Capitalized Administration ($MM)	$40
Total ($MM) (2)	$1,040 - $1,140
Other Information for 2023 Guidance	
Reclamation Activities ($MM) (3)	$40
Capital Lease Payments ($MM)	$20
Annual Operating Expenses ($/boe)	$14.25 - $15.25
Royalties	13.75% - 14.25%

1) 2023 annual average production (boe/d) is comprised of ~80% Oil & NGLs and ~20% Natural Gas
2) Land expenditures and net property acquisitions and dispositions are not included. 2023 development capital expenditures is allocated as follows: 90% drilling & development and 10% facilities & seismic
3) Reflects Crescent Point's portion of its expected total 2023 budget

Return of Capital Outlook

Base Dividend First quarter 2023 base dividend per share	$0.10
Additional Return of Capital % of discretionary excess cash flow	50%

Discretionary excess cash flow is calculated as excess cash flow less base dividends.
Additional Return of Capital % is part of a framework that targets to return up to 50% of discretionary excess cash flow.

2023 Funds Flow Sensitivity

+/- US$1.00 WTI	$40 million
+/- $0.25 AECO	$10 million
+/- $0.01 CAD/USD F/X	$30 million

Major Operating Area Economics

				US$75 WTI & $3.50 AECO	
Area	**IP30 boe/d (Liquids %)**	**EUR Mboe (Liquids %)**	**Cost Per Well (C$MM)**	**IRR%**	**Payout (Months)**
Kaybob Duvernay					
Volatile Oil	700 – 1,000 (>75%)	700 – 1,000 (>65%)	$10.5	140%	7
Liquids-Rich	1,000 – 1,500 (35 - 75%)	1,000 – 1,500 (35 – 65%)	$11.0	160%	6
Lean Gas	>1,500 (<35%)	1,500 – 2,000 (<35%)	$11.5	75%	12
Viewfield Bakken	95 – 200 (>90%)	60 – 160 (>90%)	$1.7 – $2.2	55 – 125%	9 – 16
Shaunavon	60 – 90 (>90%)	60 – 115 (>90%)	$1.9	40 – 100%	11 – 22
Flat Lake - Torquay	105 – 140 (>90%)	105 – 140 (>90%)	$3.4	50 – 100%	10 – 17
SK Conventional	80 – 130 (>90%)	70 – 250 (>90%)	$1.5	65 – 175%	6 – 18
North Dakota Bakken	600 – 765 (>90%)	460 – 560 (90%)	US$7.2	50 – 80%	9 – 13

All figures are approximates. Payouts are calculated from the initial onstream date.
Booked locations are proved and probable locations, as derived from the Company's internal reserves evaluation in accordance with NI51-101 and the COGE Handbook.

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**

Returning a meaningful amount of capital to shareholders while also creating additional value on a per share basis

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

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”, “2023E”, or “2027E”) and includes: 2023 guidance of 138,000 - 142,000 boe/d (~80% liquids) and excess cash flow expectations of $1.0B based on US$75 WTI & $3.50 AECO and development capital expenditures of $1.0 - $1.1 billion; reserves life index of ~15 years and corporate drilling inventory of >10 years; Crescent Point advantage, including, but not limited to: shareholder returns, consisting of: (a) returning 50% of discretionary excess cash flow, in addition to base dividends, (b) targeting low-to-mid single-digit growth, and (c) additional debt reduction; CPG’s portfolio optimization, including, but not limited to: asset criteria and enhanced profitability; upside in the Kaybob Duvernay; differentiated portfolio and its components; balance sheet strength; 2023E net debt and cumulative return of capital; The Kaybob Duvernay asset has significantly enhanced our long-term profitability and per-share metrics; Kaybob Duvernay market access and disciplined strategy expectations and components thereof; benefits of the position of Crescent Point’s land positioning in the Kaybob Duvernay; Kaybob Duvernay, per well, Volatile Oil EUR, Liquids Rich Gas EUR, and Lean Gas EUR as well as related expected product types; Duvernay and Montney oil and condensate EURs; 2023 expected Kaybob Duvernay production; expected Kaybob Duvernay EURs from 2010-2023; opportunity to apply efficiencies and operational execution in the Kaybob Duvernay; CPG's six fully-operated pads currently on-stream were booked at YE 2022 with an average EUR of >450 Mbbl; Kaybob Duvernay wells are high return and quick payout; Kaybob Pad 2 condensate EUR, Gas EUR, NGL EUR and Total EUR, NPB 10, IRR%, Pi10 and payout; Kaybob Duvernay regions’ NPV 10%, Payout, IRR% and net inventory; locations in Kaybob Duvernay underpinning corporate 10-year plan; offsetting EURs and the implications for Crescent Point; Kaybob area market access and egress expectations; WCSB condensate supply / demand balance and expectations; Canadian condensate pricing benefits from an undersupplied domestic market and a strong expected demand outlook due to oil sands growth, which uses condensate as a diluent; ~20% of CPG’s 2023E liquids production is condensate and receives strong pricing relative to WTI; Montney, Deep Basin & Duvernay Production vs. Egress; Coastal Gas Link/LNG Canada are expected to come online by 2025 providing an outlet for WCSB natural gas growth; other probable LNG projects provide further line of site to long term growth; continuing to evaluate other opportunities to further diversify our gas sales portfolio; future Kaybob Duvernay infrastructure; future capital required to facilitate 10-yr development; >10 years of risked corporate inventory supports long-term development plan, and the characteristics and expectations of Crescent Point’s inventory by area; long-term sustainability and near-term development, and upside of major areas; Kaybob Duvernay opportunities including: enhanced efficiencies, unbooked reserves growth, and down-spacing & step-out drilling; opportunities in Saskatchewan including further decline mitigation, step-out drilling and advancing new technology / D&C practices; the Three Forks development opportunity in North Dakota; timing to payoff Kaybob Duvernay acquisition; increasing % of capital allocated to Kaybob Duvernay in 5 and 10-year plan; Kaybob’s attractive netbacks support significant excess cash flow generation while the asset continues to grow; 2023 Financial Outlook for Major Operating Areas, including each of the expected metrics listed in the presentation; Total corporate inventory including, but not limited to: ~2,000 locations drilled in the 10-year plan and ~5,000 locations in corporate inventory; highly economic long-term development plan, drilling expectations, economics of premium locations; availability of additional locations and their potential recategorization; risked inventory ROR’s by major operating areas; 2023E and 2027E production and FCF (% of Corp.) by major operating area; 5- and 10- year outlooks, including but not limited to production in 2023E, 2027E and 2032E, production CAGR, capital expenditures, cumulative excess cash flow, reinvestment ratio, net cash, decline rate, and cumulative after-tax excess cash flow and per share amounts; Crescent Point strategy; returns based capital allocation framework; summary of Kaybob Duvernay attributes; 5-year plan generates $3.0 - $5.8B of cumulative excess cash flow, based on assumptions specified, which more than doubles in 10-year plan; Kaybob Duvernay acquisitions payback timing; plans to grow Kaybob Duvernay production; increasing value in Kaybob Duvernay; Crescent Point’s annual guidance for 2023, including, but not limited to annual average production, capital expenditures (including development capital expenditures and capitalized administration) and other information (including reclamation activities, capital lease payments, annual operating expenses and royalties); 2023 funds flow sensitivity; return of capital outlook, including additional return of capital as a percentage of discretionary excess cash flow and base dividend; major operating areas economics including, but not limited to EURs, IRR%, and Payout; and returning a meaningful amount of capital to shareholders while also creating additional value on a per share basis; and the return of capital framework and components. 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 due to the effect 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 Corporation is contained in its Annual Information Form for the year ended December 31, 2022, which is accessible at www.sedar.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 Crescent Point’s beliefs and assumptions based on information available at the time the assumption was made. Crescent Point 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, 2022 under "Risk Factors“ and our Management’s Discussion and Analysis for the year ended December 31, 2022, 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, 2022, under the headings "Capital Expenditures", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Guidance“. 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 in business operations or delivery of services due to pipeline restrictions, rail blockades, outbreaks, blowouts and business closures and social distancing measures mandated by public health authorities in response to COVID-19; 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; 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 severe weather events; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions, including uncertainty in the demand for oil and gas and economic activity in general as a result of the COVID-19 pandemic; changes in interest rates and inflation; uncertainties associated with regulatory approvals; geopolitical conflict, including the Russian invasion of Ukraine; uncertainty of government policy changes; the impact of the implementation of the Canada-United States Mexico Agreement; 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 Crescent Point’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; Crescent Point’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, Crescent Point 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 Crescent Point’s 2023 guidance in respect of capital expenditures, average annual production, 5- and 10- year plans and 2023 Financial Outlook which are 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 Crescent Point. 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.

Disclosure Committee

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, Crescent Point 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.

Definitions / Specified Financial Measures

Throughout this presentation the Company uses the terms “operating netback” (equivalent to netback), “adjusted funds flow” (equivalent to “funds flow”), “excess cash flow”, “discretionary excess cash flow”, “total return of capital”, “net debt” and “net debt / funds flow” (equivalent to net debt to adjusted funds flow from operations and to leverage ratio), 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, there, may not be comparable with the calculation of similar measures presented by other entities.

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.

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.

Excess cash flow and discretionary excess cash flow for 2023 are forward-looking non-GAAP measures. Refer to the Specified Financial Measures section of the Company’s MD&A for the period ended December 31, 2022.

The most directly comparable financial measure for excess cash flow, discretionary excess cash flow and adjusted funds flow disclosed in the Company’s financial statements is cash flow from operating activities, which, for the year ended December 31, 2022, was $2.19 billion. The most directly comparable financial measure for net debt disclosed in the Company’s financial statements is long-term debt, which for the year ended December 31, 2022, was $1.44 billion. For the year ended December 31, 2022, total operating netback, operating netback, excess cash flow, discretionary excess cash flow, adjusted funds flow and net debt were $3.04 billion and $62.94/boe, $1.15 billion, $1.00 billion, $2.23 billion, $1.15 billion, respectively.

Definitions / Specified Financial Measures

For an explanation of the composition of operating netback, adjusted funds flow, excess cash flow, discretionary excess cash flow, net debt and net debt / funds flow, 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, 2022 at www.sedar.com, or EDGAR at www.sec.gov and on our website at www.crescentpointenergy.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 and 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. 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 “operating netback”, “payout”, “reserves life index” “NPV10”, “PI10”, “IRR%”, “reinvestment ratio” and "decline rate". 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.

Operating netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

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.

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.

NPV10 is the net present value of a particular cash flow discounted using a discount rate of 10% per year. It is used to give an indication of the value of future cash flows.

PI10 is the profitability index for a particular investment, using a discount rate of 10%, it is calculated by dividing the present value of future expected cash flows by the initial investment. It is used to determine the expected profitability of an investment.

IRR% means internal rate of return. It is the discount rate used to make the net present value of expected cash flows equal to zero. It is used to evaluate the profitability of an investment.

Reinvestment ratio is development capital expenditures as a percentage of cash flow. It is used to measure the amount of cash the company invests back into the business.

Reserve Life Index is calculated as proved plus probable reserves divided by production, and it is a measure of the longevity of the Company’s reserves.

This presentation references drilling inventory, which includes 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 National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”), 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.

Reserves and Drilling Data

All reserves data contained in this presentation, and effective for the year ended 2022, is contained in the Corporation's AIF for the year ended, December 31, 2022, available on SEDAR (the "Reserves Report") and prepared in accordance with the standards contained in NI 51-101 and the COGE Handbook that were in effect at the relevant time. 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.

Kaybob Duvernay production at the time of the Shell acquisition of 30,000 boe/d consists of 57% condensate, 8% NGL and 35% shale gas.

Kaybob Duvernay Paramount assets at acquisition of 4,000 boe/d consists of 35% condensate, 15% NGL and 50% shale gas.

IP30 Production Results from Kaybob Duvernay Pads by Product Type			
Pad	Condensate	NGL	Shale Gas
Pad 1	73%	7%	20%
Pad 2	71%	8%	21%
Pad 3	81%	5%	14%
Pad 4	67%	9%	24%
Pad 5	50%	16%	34%
Pad 6	51%	15%	34%
Pad 7	38%	10%	52%
Pad 8	38%	10%	52%
Pad 9	32%	11%	57%

IP90 Production Results from Kaybob Duvernay Pads by Product Type			
Pad	Condensate	NGL	Shale Gas
Pad 1	70%	8%	22%
Pad 2	69%	8%	23%
Pad 3	80%	5%	14%
Pad 4	64%	10%	26%
Pad 5	49%	15%	36%
Pad 6	N/A	N/A	N/A
Pad 7	37%	10%	53%
Pad 8	35%	11%	54%
Pad 9	29%	12%	59%

Booked EUR from Kaybob Duvernay Pads by Product Type			
Pad	Condensate	NGL	Shale Gas
Pad 1	72%	7%	21%
Pad 2	70%	8%	22%
Pad 3	81%	5%	14%
Pad 4	66%	9%	25%
Pad 5	49%	15%	36%
Pad 6	32%	19%	49%
Pad 7	21%	22%	57%
Pad 8	22%	22%	56%
Pad 9	21%	22%	57%

Initial production is for a limited time frame only (30, or 90 days) and may not be indicative of future performance.

This presentation discloses: (I) in the Kaybob Duvernay: (A) an aggregate of 500 potential internally identified net drilling locations, of which 126 are proved plus probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 374 are unbooked locations, (B) Volatile Oil region, 225 potential internally identified net drilling locations, of which 104 are proved plus probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 85 are unbooked locations; (C) Liquids-Rich region 125 potential internally identified net drilling locations, of which 17 are proved plus probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 108 are unbooked locations; and (D) Lean Gas region 150 potential internally identified net drilling locations, of which 5 are proved plus probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 145 are unbooked locations; and (II) ~5,000 locations in corporate inventory of which of which 1,555 are proved plus probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 3445 are unbooked locations.

Reserves and Drilling Data

Years of corporate inventory figures include proved and probable locations, as derived from the independently evaluated (by McDaniel & Associates Consultants Ltd.) Reserves Report 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.

Unless otherwise specified, data is based on internal evaluation and was not prepared by an independent qualified reserve evaluator.

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, Crescent Point 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, Crescent Point 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, Crescent Point'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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