Canadian Natural

CORPORATE PRESENTATION

FEBRUARY 2026

Canadian Natural
Unparalleled Independent – Assets, Execution & Resilience

Capital Markets & Financial Summary

Ticker symbol	TSX: CNQ / NYSE: CNQ
Shares outstanding(1)	~2,085 million
Market capitalization(2)	~$106 billion
Net Debt(1)	~$17 billion → 0.9x Net Debt to EBITDA
Enterprise value(2)	~$110 billion
Annualized dividend(3)	~$2.35/share
Dividend yield(2)(3)	5.3%

Operations Summary

Production(1)	~1,620 MBOE/d → largest in Canada
Liquids weighting(1)	~73%
Total proved reserves(4)	~11.8 billion BOE → largest in Canada and 2nd largest among global peers
Net acres(1)	~27 million acres (48% undeveloped) → providing deep inventory of future value creation opportunities

(1) As of September 30, 2025. Debt to adjusted EBITDA is 12-month trailing.
(2) Based on January 29, 2026 closing share price.
(3) Based on current quarterly dividend of $0.5875 per common share, annualized.
(4) Total proved company net reserves, based on SEC constant prices and costs, as of December 31, 2024.

Canadian Natural Strategy

Unparalleled Independent – Assets, Execution & Resilience

Unparalleled Assets

- Disciplined value creation
- Large, Diverse, Balanced asset base
- Significant long life low decline production
- Extensive infrastructure ownership & operatorship in core areas

Unparalleled Execution

- Effective & efficient operations
- Industry-leading performance driven by safety, reliability, and cost efficiency
- Culture of accountability and continuous improvement
- Low maintenance capital assets with low breakeven
- ESG commitment

Unparalleled Resilience

- Strong Balance Sheet
- Supported by investment grade credit ratings
- Balance sheet strengthening further with free cash flow policy
- Significant returns to shareholders

Canadian Natural

Unparalleled competitive advantages

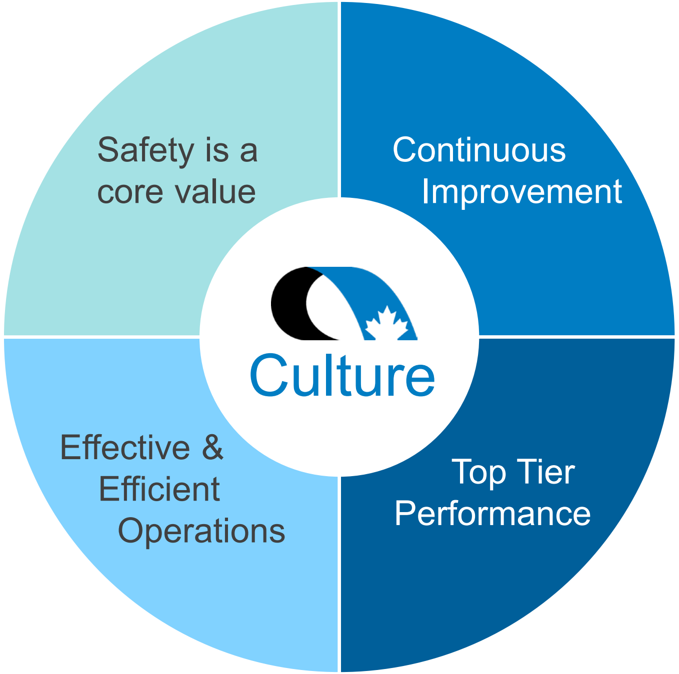
Large, Low Risk, High Value Reserves	Diversified, Balanced Asset Base	Lower Capital Reinvestment Requirements	Flexible Capital Allocation	Effective & Efficient Operations

Consistently driving long-term shareholder value

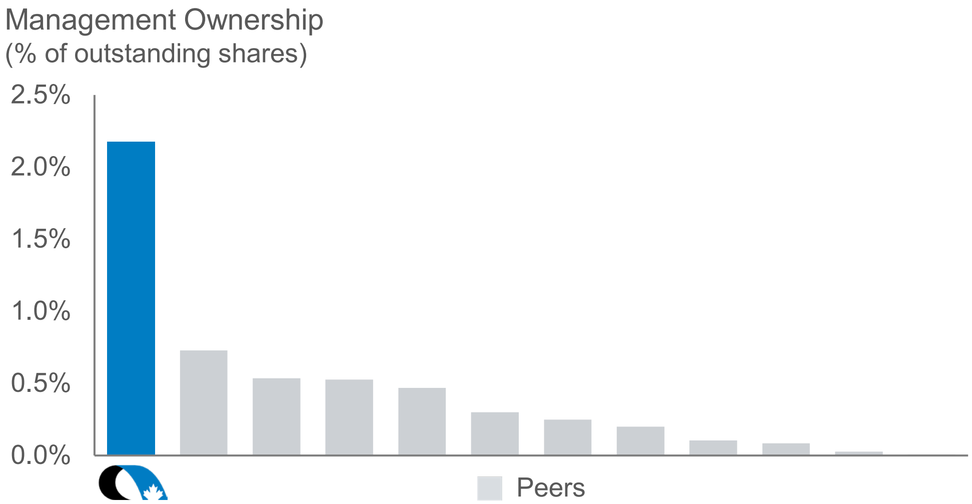
- Execution
- Unique Culture
- Free Cash Flow Generation
- Strong Shareholder Returns

Canadian Natural

Unparalleled competitive advantage – culture



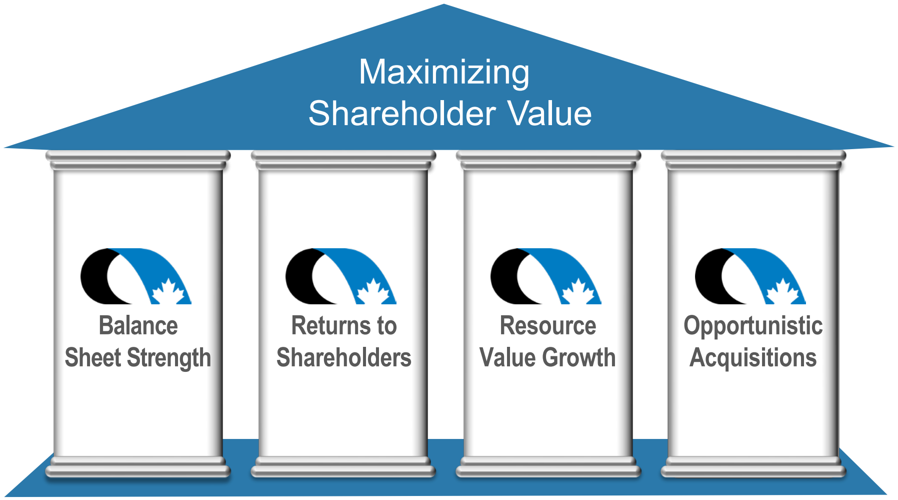
All employees are shareholders → Drives accountability & shareholder alignment



Peers include: APA, COP, CVE, CVX, DVN, EOG, IMO, OVV, OXY, SU and XOM.
Source: BD Corporate share ownership data as of October 2025 (excluding options).

Canadian Natural

Unparalleled disciplined capital allocation – balancing the four pillars



Balance Sheet Strength
Balance Sheet strengthens with free cash flow generation

Returns to Shareholders
Growing, sustainable dividends & opportunistic share repurchases

Resource Value Growth
Disciplined capital allocation, focused on asset development & margin growth

Opportunistic Acquisitions
No gaps / must add value

FLEXIBLE CAPITAL ALLOCATION MAXIMIZES SHAREHOLDER VALUE

Canadian Natural's Extensive Reserves on a Global Scale

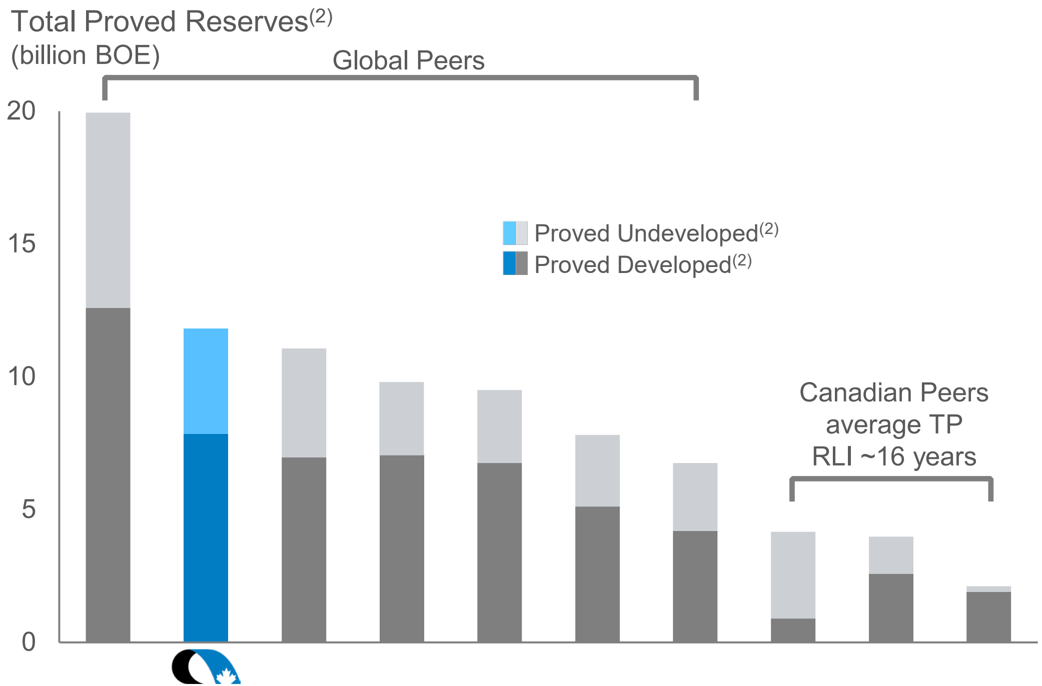
Global & Canadian energy peers

2nd Largest Reserves
among global energy peers

Largest among
Canadian peers

Only Canadian company with
>5 billion BOE
total proved reserves

~32 year
total proved Reserve Life Index(1)

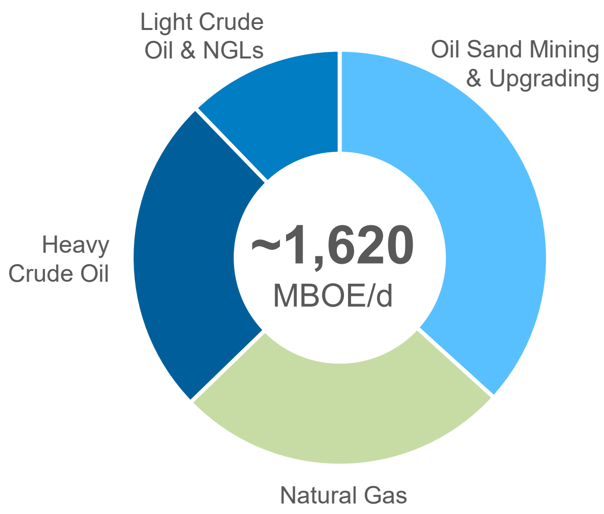


TP Reserves to Market Cap(2) (BOE/US$1,000)	41	177	81	31	43	71	73	139	83	46

(1) RLI is calculated using 2024 total proved net reserves, based on SEC constant prices and costs, divided by the estimated 2025 proved developed producing net production.
(2) Net proved reserves, based on SEC constant prices and costs, per company reports, as of December 31, 2024. Market capitalization as of October 30, 2025.
Note: Peers include BP, COP, CVX, SHEL, TTE, XOM, CVE, IMO & SU.

Canadian Natural's Unique Portfolio
Unparalleled assets

Production Mix
(2026B)



~1,620 MBOE/d
(~1.2 Mbbl/d & ~2.5 Bcf/d)

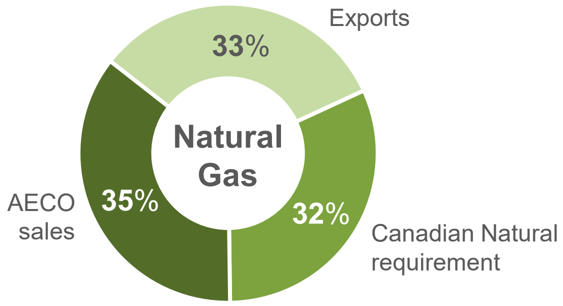
Largest crude oil producer &
2nd largest natural gas producer
in Canada

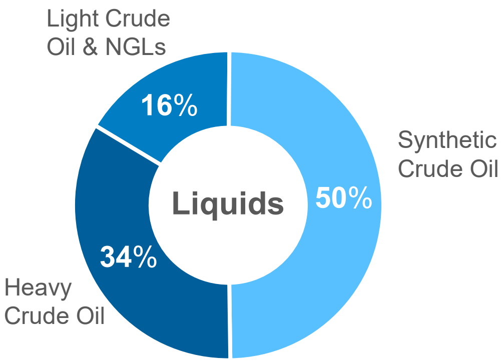
~64%
of liquids production is high value
SCO, light crude oil & NGLs

Maximize netbacks
with balanced sales points

~823 MMcf/d & ~256 Mbbl/d
of committed export volumes

Balanced Sales Points & Products



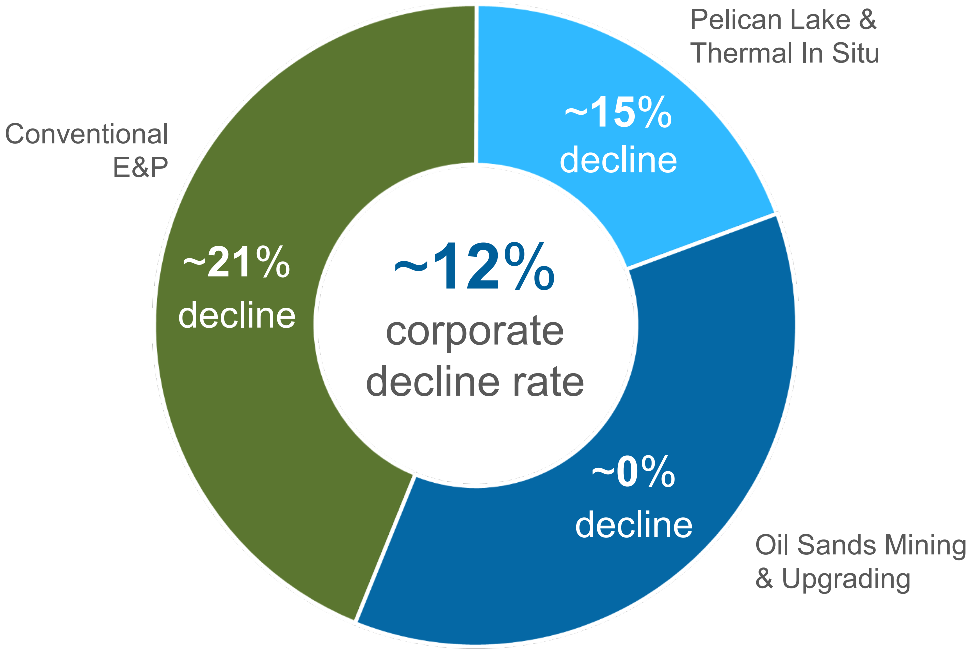


(1) Based upon the mid-point of 2026 budgeted production guidance range.

Canadian Natural's Advantage

Low corporate decline rate results in lower capital reinvestment requirements

Asset Product Mix(1)



~56%
of our production is from
Long Life Low Decline assets

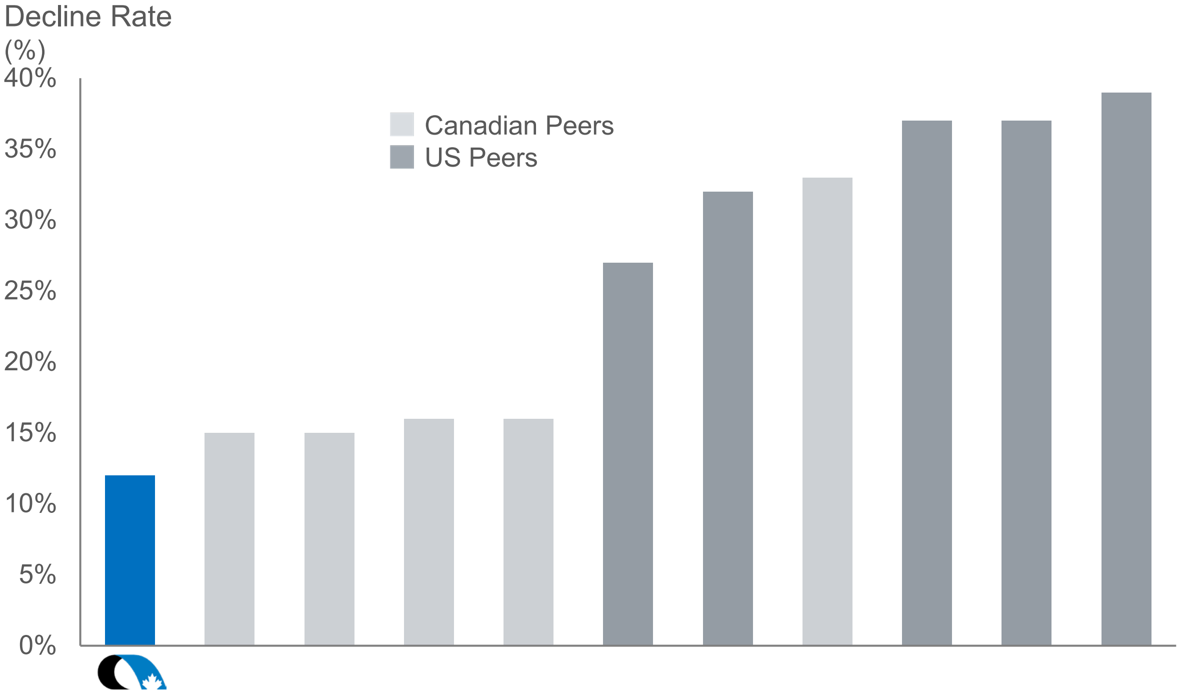
(1) Based upon the mid-point of the 2026 budgeted production guidance range.
Note: Conventional E&P assets include North America natural gas, NGLs, light crude oil, heavy crude oil, International crude oil and natural gas.

Canadian Natural's Differentiating Value

Long life low decline asset base

~12%
Leading corporate decline rate

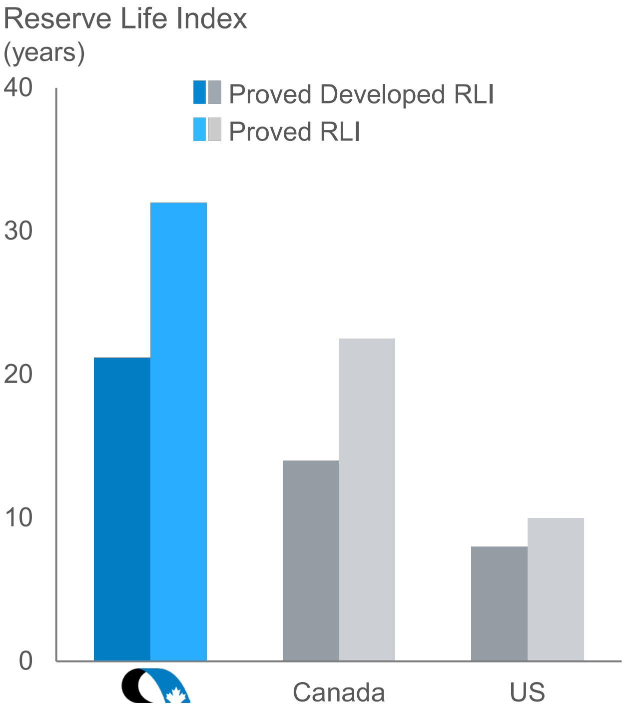
$9 to $10/BOE
Low maintenance capital



Peers include: APA, CVE, DVN, EOG, FANG, IMO, MEG, OVV, SU and TOU.
Source: Canadian Natural internally estimated decline rate and Peters & Co. estimated annual corporate decline rate for 2026 as of September 2025 for peers.

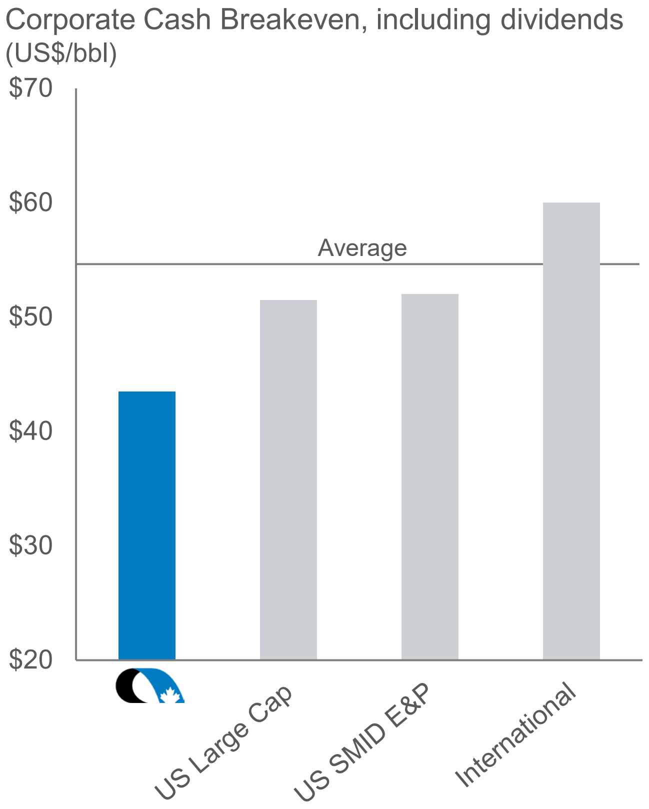
Canadian Natural's Differentiating Value

Long life reserves & low breakeven



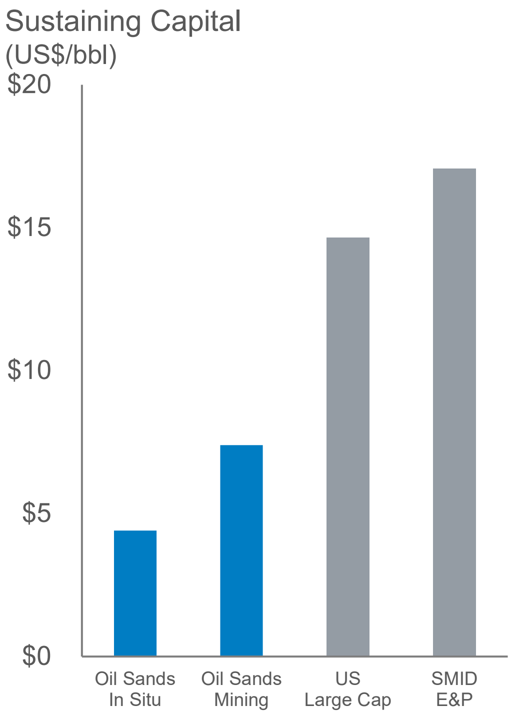
Decades
of high quality reserves

Low to mid-
$40s/bbl
breakeven
supports long-term sustainability



Source: BMO Research, "I Want What You Got: Canada's Oil Resource Advantage" report, April 2025. Breakeven includes dividends.

Canadian Natural's Differentiating Value
Low-cost source of sustained supply

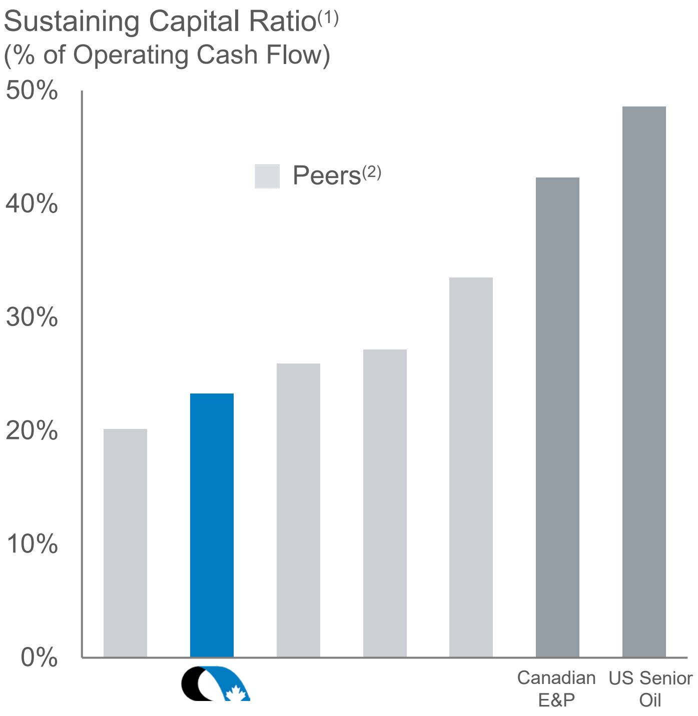


Oil Sands require significantly lower sustaining capital

~US**$4**/BOE In Situ

~US**$8**/BOE Mining

Low cost source of sustained supply

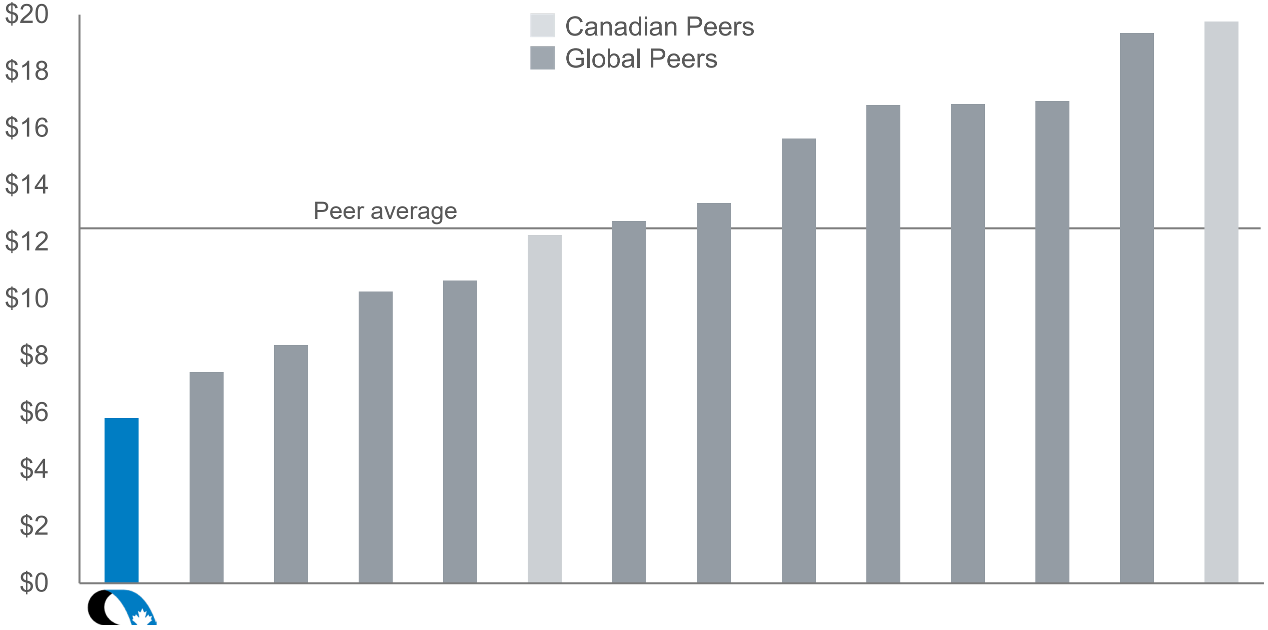


(1) BMO's estimate of 2026 corporate sustaining capital (capital required to keep production flat) over operating cash flow.
(2) Peers include: CVE, IMO, MEG and SU.
Source: BMO Research, "I Want What You Got: Canada's Oil Resource Advantage" report, April 2025.

Industry Leading FD&A Costs
Five-year average

Top tier FD&A costs
<US$6/BOE
driven by cost effective development of high quality reserves

FD&A Costs (five-year, 2020-2024)
(US$/BOE)



Peers include: APA, BP, COP, CVE, CVX, DVN, EOG, OVV, OXY, SHEL, SU, TTE and XOM.
Source: Company reports, SEC Filings. Five-year average, includes revisions. Where companies have reported in Canadian dollars, C$ to US$ foreign exchange rates at December 31 of each year of 0.7855 for 2020, 0.7911 for 2021, 0.7369 for 2022, 0.7539 for 2023, and 0.6948 for 2024 were used.

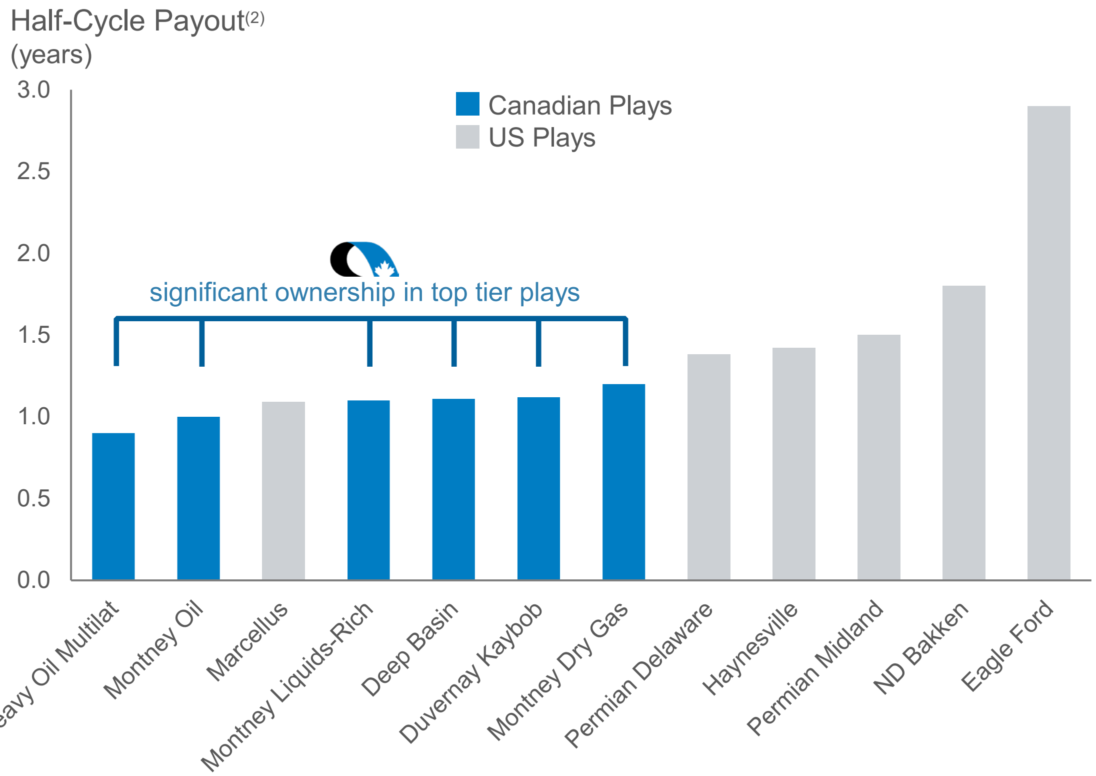
Conventional E&P

Top tier plays throughout the asset base

~25 million net acres
within high quality
Conventional plays in
North America

Multi-decade inventory with
>10,000 locations(1)

Top tier areas of
focus include the
Heavy Oil Multilaterals, Montney, Deep Basin & Duvernay

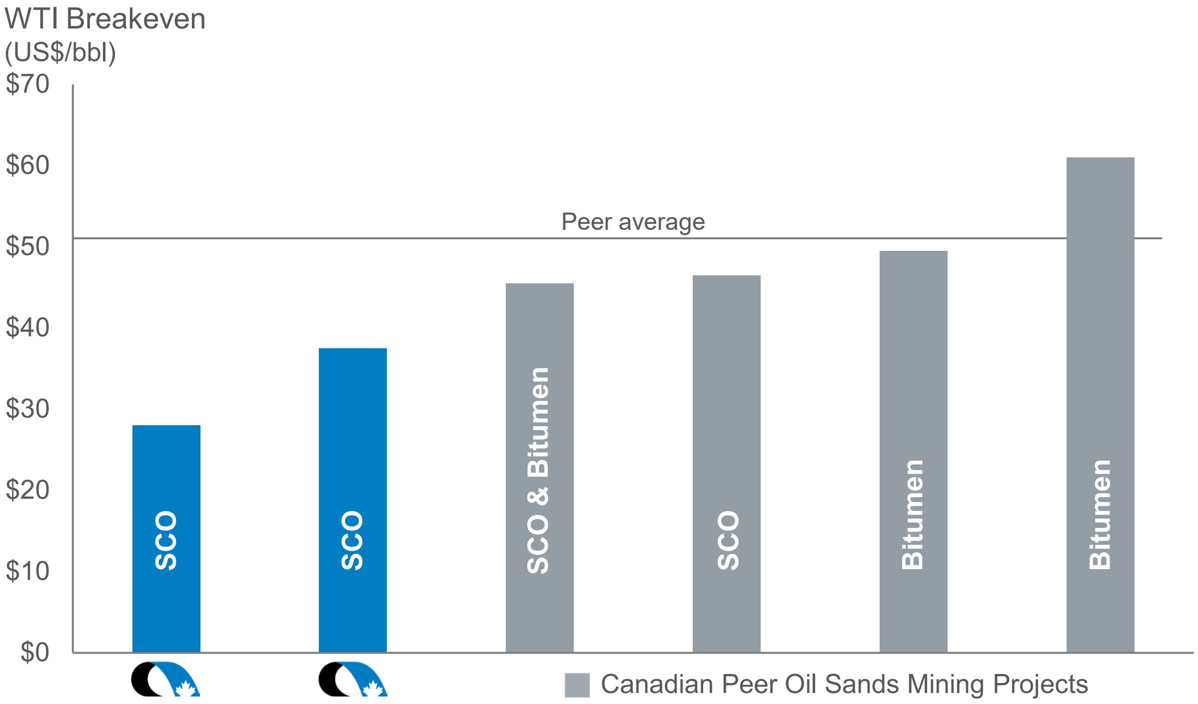


(1) Assumes US$65/bbl WTI, US$12/bbl WCS differential, C$2.50/GJ AECO and US$1.00 to C$1.35 foreign exchange.
(2) Source: Peters & Co. Fall 2025 Energy Overview.

World Class Oil Sands Mining Assets
Leading WTI breakeven price

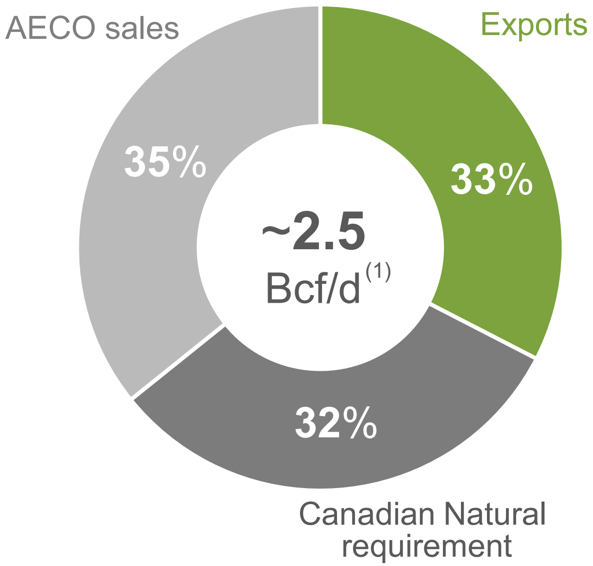
~592,000 bbl/d
of upgrader capacity,[1]
90% of which is
high value SCO

Long life no decline
Oil Sands Mining assets and
effective & efficient operations
support a
low WTI breakeven
price, delivering
superior returns



Peers include: IMO Kearl, SU Base Ops (including thermal in situ), SU Fort Hills and Syncrude.
(1) Two-year average upgrader capacity reflects 100% interest in the Albian mines following the close of the previously announced swap transaction.
Source: Peters & Co. Fall 2024 Energy Overview – Breakeven defined as WTI crude oil price required for a project to be free cash flow neutral.

Natural Gas Markets
Balanced portfolio maximizes value



~823 MMcf/d
exported, capturing stronger North American pricing

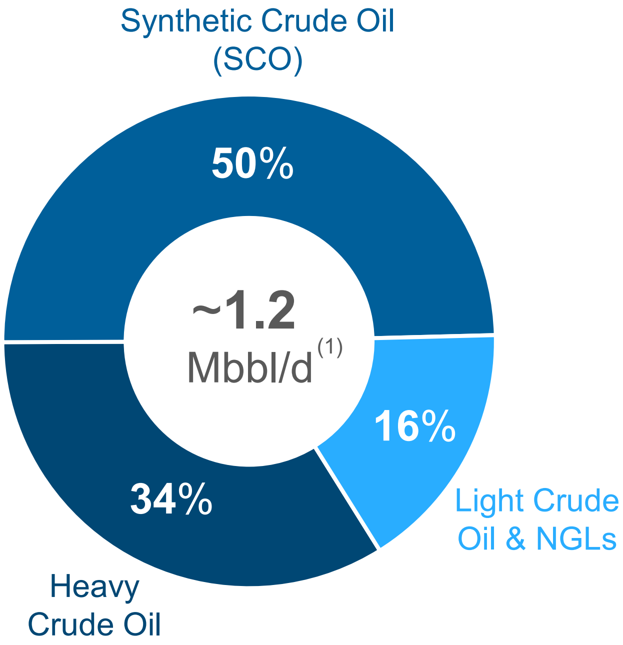
~$375 million
incremental margin in 2025F through diversified sales points

2026B Exports

Export Point	MMcf/d	Percent
Dawn	243	29%
Iroquois	7	1%
Emerson	197	24%
Empress	103	13%
Malin	70	9%
Alliance	203	24%
Total	823	100%

(1) Based upon the mid-point of the 2026 budgeted production guidance range.

Crude Oil Markets
Balanced portfolio maximizes value – crude oil



~66%
high value
light crude oil,
NGLs & SCO

~34%
high return &
netback heavy
crude oil

256,500 bbl/d of committed exports

- 169,000 bbl/d on TMX to west coast of Canada
- 77,500 bbl/d on Flanagan South to the USGC
- 10,000 bbl/d on Base Keystone to the USGC

21% of liquids production exported

- Access to expanded refining markets
- Drives stronger netbacks
- Reduces exposure to egress restraints

WCS Differential

- TMX has minimized volatility of the differential
- 2026 forward strip differential at ~US$14.00/bbl
- Strong heavy oil pricing targeted in 2026

(1) Based upon the mid-point of the 2026 budgeted production guidance range.

Canadian Natural

2026 Budget

2026 Budget
Production Guidance & Capital Budget

Production Guidance[1]	**2026B**
Natural Gas (MMcf/d)	2,477 - 2,577
Conventional E&P Crude Oil & NGLs (Mbbl/d)	325 - 337
Thermal and Oil Sands Mining & Upgrading (Mbbl/d)	852 - 883
Total Liquids (Mbbl/d)	1,177 - 1,220
Total (MBOE/d)	1,590 - 1,650

Capital Budget ($ millions)[2]	**2026B**
Conventional E&P	$3,320
Thermal In Situ and Oil Sands Mining & Upgrading	$2,980
Subtotal – Operating Capital	$6,300
Carbon Capture	$125
Total Capital	$6,425

~50,000 BOE/d or
~3%
of production growth from 2025 levels

Resource **value growth** through **flexible capital** allocation to optimize production levels

(1) Reflects planned downtime for turnaround activities in all areas.
(2) Our 2026 capital budget excludes net acquisitions and ~$993 million of abandonment expenditures, before recoveries.
Note: Rounded to the nearest 1,000 bbl/d and $ million. See Advisory for cautionary statements, definitions, pricing assumptions and Non-GAAP and Other Financial Measures disclosure.

2026 Budget
Conventional and Thermal

Conventional E&P Drilling (net producer wells)	**2026B**
Natural Gas wells	86
Primary Heavy	237
Pelican Lake	15
Light	110
International	-
Total Crude Oil wells	362
Total Conventional E&P wells	**448**

Thermal In Situ Drilling (net producer wells)	**2026B**
CSS & SAGD	76
New wells on existing mature pads	46
Total Thermal wells	**122**

Heavy crude oil

- Focused on the successful multilateral horizontal drilling program in Primary Heavy Oil

Light crude oil and liquids-rich natural gas drill-to-fill

- Focused on the Montney, Duvernay, Mannville, Dunvegan & Charlie Lake

Thermal In Situ

- Two Pike 1 SAGD pads targeted to come on production Q1/26 and Q2/26
- Drilling three Primrose CSS pads, with the first pad targeted to come on production in Q3/26
- Drilling one Kirby North SAGD pad, targeted to come on production in 2027
- Drilling program of 46 new wells on existing mature pads

Progressing FEED engineering medium-term growth projects

- Jackfish Thermal Brownfield expansion
- Pike 2 Greenfield expansion growth projects

2026 Budget
Oil Sands Mining & Upgrading

Horizon

- Progressing the Naphtha Recovery Unit Tailings Treatment ("NRUTT") project
  - Targets incremental production in Q3/27 of approximately 6,300 bbl/d of SCO following mechanical completion
- Planned turnaround planned in Q3/26
  - Targeting a 35-day turnaround to begin in September 2026, impacting annual average production by ~29,000 bbl/d
  - As part of Horizon's two-year turnaround cycle, the Company targets that the next turnaround will be in 2028

AOSP

- Jackpine Mine expansion – Front End Engineering in 2026
- Optimize operations following the completion of the Swap transaction
  - Canadian Natural now owns and operates 100% of the Albian mines, including associated reserves
  - Retains a non-operated 80% interest in the Scotford Upgrader and Quest facilities

Shareholder Returns & Balance Sheet Strength

Canadian Natural Consistently Delivering Long-term Shareholder Value

2025F

Low
maintenance capital &
disciplined
capital program

Production
per share
growth of
~16%

Executed on
highly
accretive
acquisitions

Asset base drives
resilience,
value growth
& **upside**

Significant
shareholder returns of
~$8.2 billion
or **~$3.95/**sh,
including net debt
reduction

Increased
annual dividends
paid by **~12%**
to **$2.35**/sh

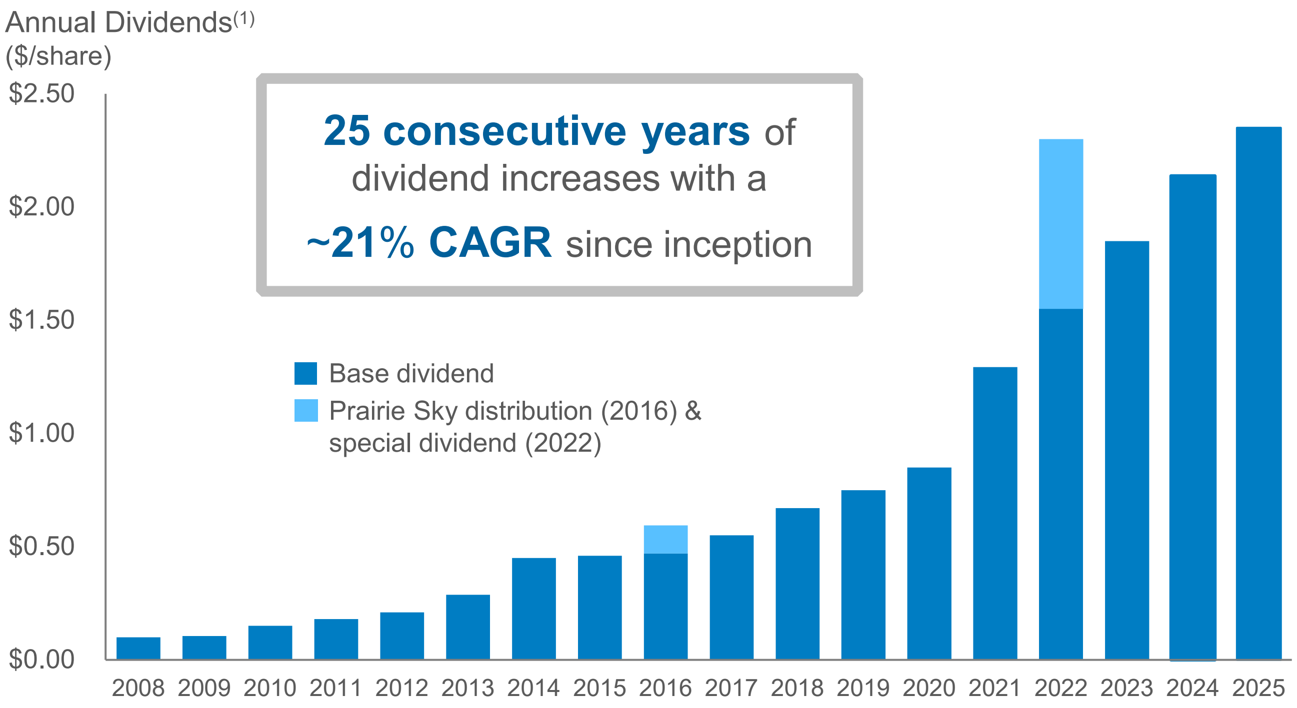
Strong
balance sheet
with current liquidity
of **~$4.3** billion

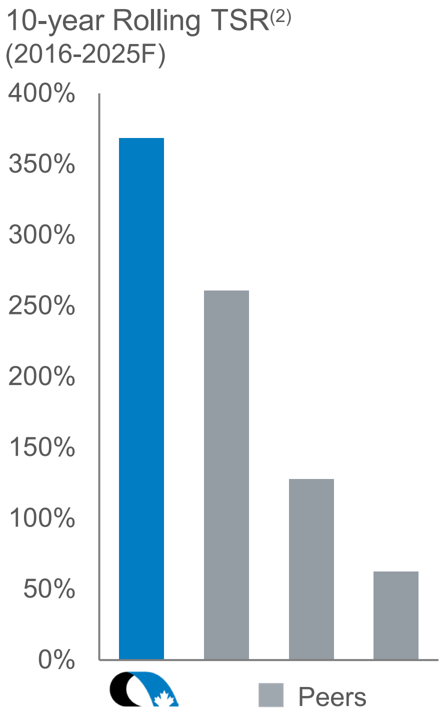
Year-end 2025
net debt
forecast of
~$16.8 billion

HIGH QUALITY, LONG LIFE LOW DECLINE ASSET BASE SUPPORTS LONG-TERM VALUE

Canadian Natural

Leading history of growing returns to shareholders





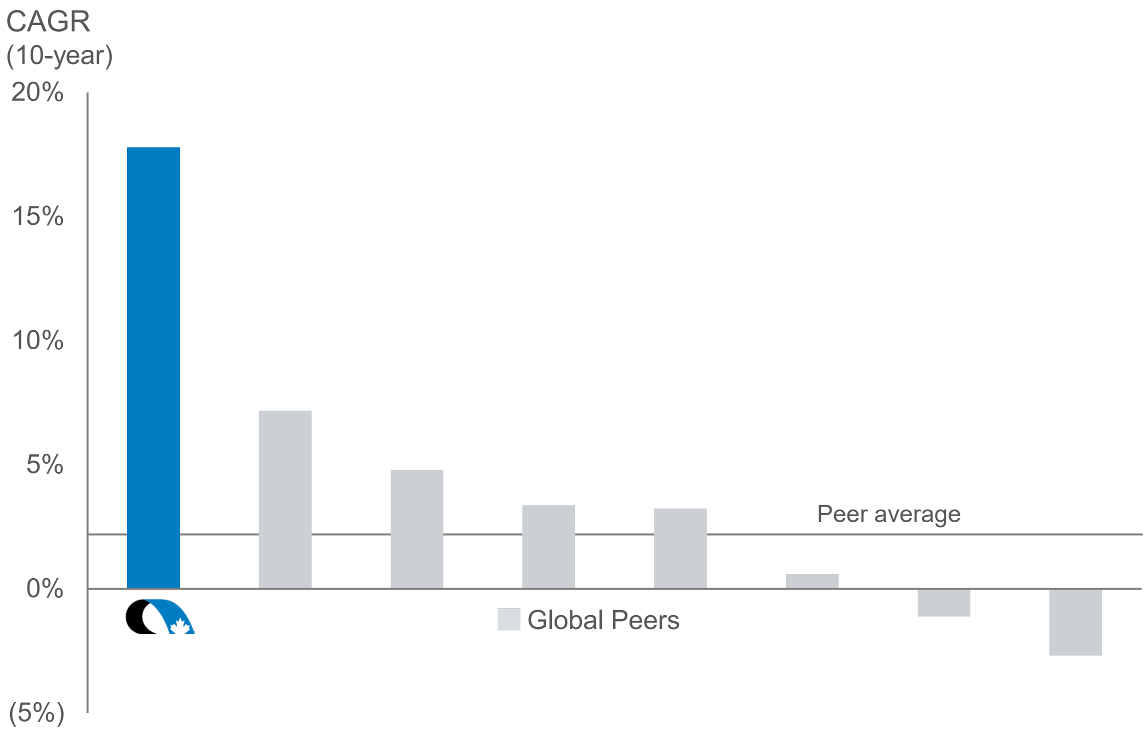
(1) Based upon annual dividends declared. 2026F based upon current quarterly declared dividend, annualized.
(2) Based on October 30, 2025 share price. Peers include CVE, IMO and SU.
See Advisory for cautionary statements, definitions, pricing assumptions and Non-GAAP and Other Financial Measures disclosure.

Long-Term Dividend Growth vs. Global Peers
10-year CAGR

Leading long-term **dividend growth**

Sustainable dividend was maintained & increased in low commodity price periods while others cut

$2.35 per share current annualized dividend



Peers include: BP, COP, CVX, SHEL, SU, TTE and XOM.
Note: Annual dividends paid in 2015 compared to current dividend, annualized, as per company reports.

Canadian Natural

Free Cash Flow Allocation Policy

Adjusted Funds Flow

less: Total Capital(1)

less: Dividends

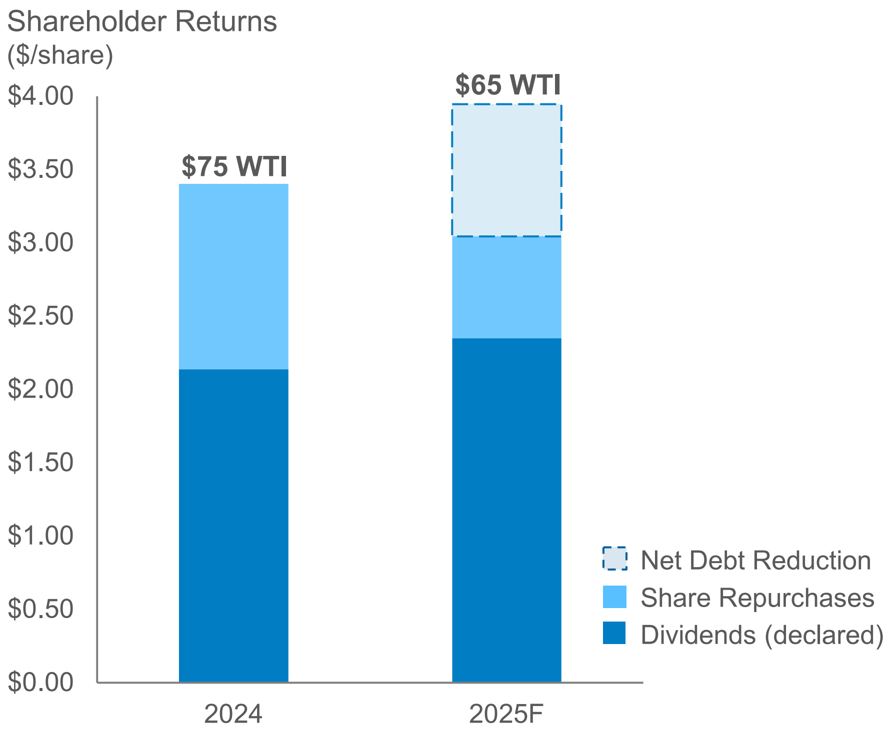
Free Cash Flow

when net debt is >**$15** billion	when net debt is **$12 - 15** billion	when net debt is **$12** billion
60% of FCF returned to Shareholders	**75%** of FCF returned to Shareholders	**100%** of FCF returned to Shareholders

(1) Total Capital reflects net capital expenditures, including abandonment expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on net capital expenditures.

Note: See Advisory for cautionary statements, definitions, pricing assumptions and Non-GAAP and Other Financial Measures disclosure.

Free Cash Flow Allocation
Significant returns to shareholders



	2024	2025F
FCF allocation	100%	60%

2024 returns to shareholders totaled

~$3.40 per share

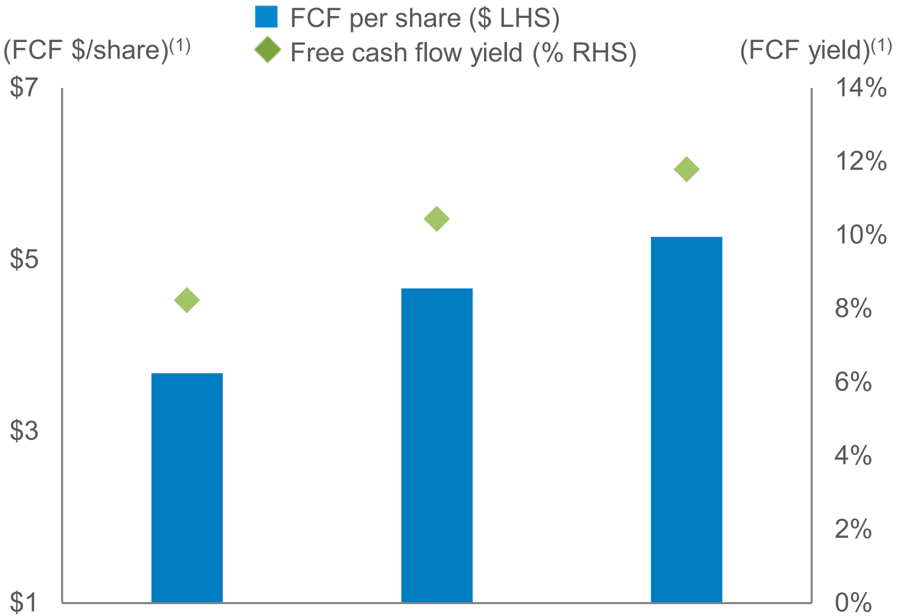
when 100% of free cash flow was allocated to shareholders

2025 estimated returns to shareholders, including net debt reduction, totals

~$3.95 per share

when 60% of free cash flow is allocated to shareholders, with WTI down ~US$10/bbl

Free Cash Flow Sensitivity
Adjusted funds flow less capital



WTI (US$/bbl)	$60	$70	$80
AECO (C$/GJ)	$3.00	$3.00	$3.00

~28% higher
free cash flow per share
at US$70 WTI vs US$60 WTI

~45% higher
free cash flow per share
at US$80 WTI vs US$60 WTI

Significant torque
to commodity prices

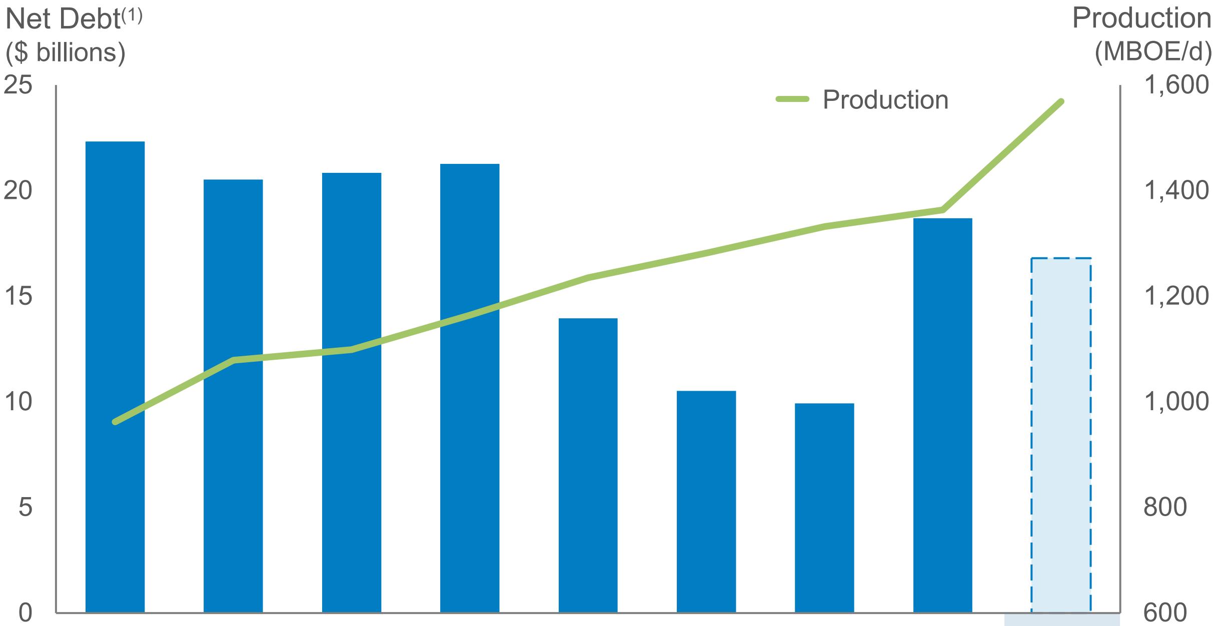
(1) Free Cash Flow = Adjusted Funds Flow less operating capital. Does not include dividends. Free cash flow yield based upon closing share price on October 30, 2025 and annual estimated 2026F potential free cash flow.

Canadian Natural
Balance Sheet continues to strengthen

~$16.8 billion
net debt at year-end 2025[1]

Strengthening metrics
through the commodity price cycle and following acquisitions

Net Debt to Production
materially below the ranges of 2017 to 2020 and production has grown by
~600,000 BOE/d

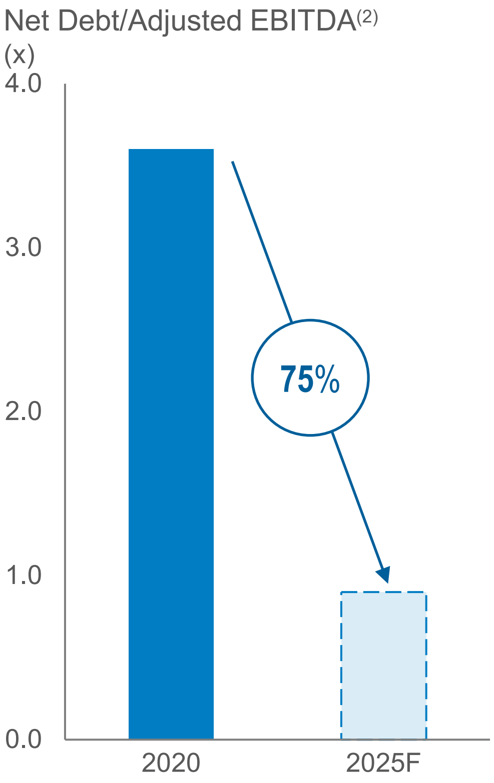


	2017	2018	2019	2020	2021	2022	2023	2024	**2025F**
Net Debt to Production ($/BOE/d)	$23,200	$19,020	$18,970	$18,270	$10,890	$7,900	$7,450	$13,710	**$10,700**
WTI (US$/bbl)	$50.93	$64.78	$57.04	$39.16	$68.13	$94.90	$77.61	$75.72	**$64.97**

(1) See Advisory for definitions, pricing assumptions, Non-GAAP and Other Financial Measures disclosure.

Canadian Natural

Financial position strengthens following period of opportunistic acquisitions

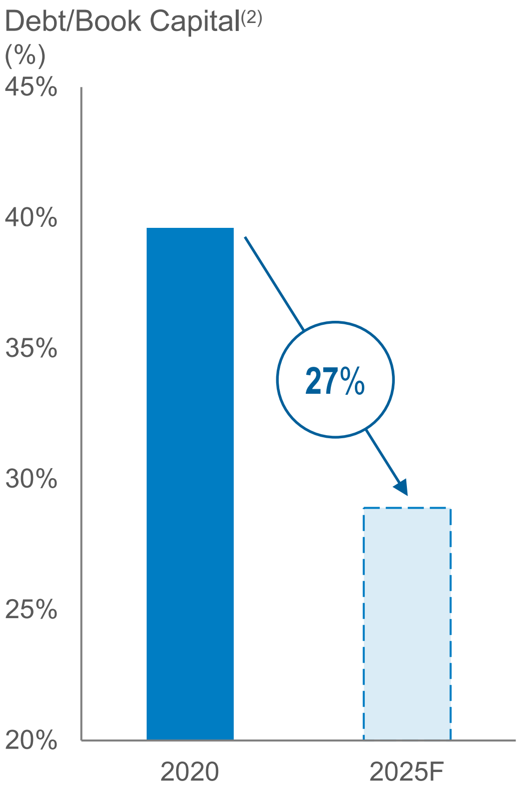


~$16.8 billion
Net debt[1]

~29%
Debt to book capitalization[1]

~0.9x
Debt to adjusted EBITDA[1]

~$4.3 billion
liquidity[2]



(1) *Year end 2025F.*
(2) *As of September 30, 2025.*

Canadian Natural
Robust financial position

Support from **13** banks diversified by location

15+ year relationships with 12 banks

Liquidity of ~**$4.3** billion(2)

Investment Grade credit ratings

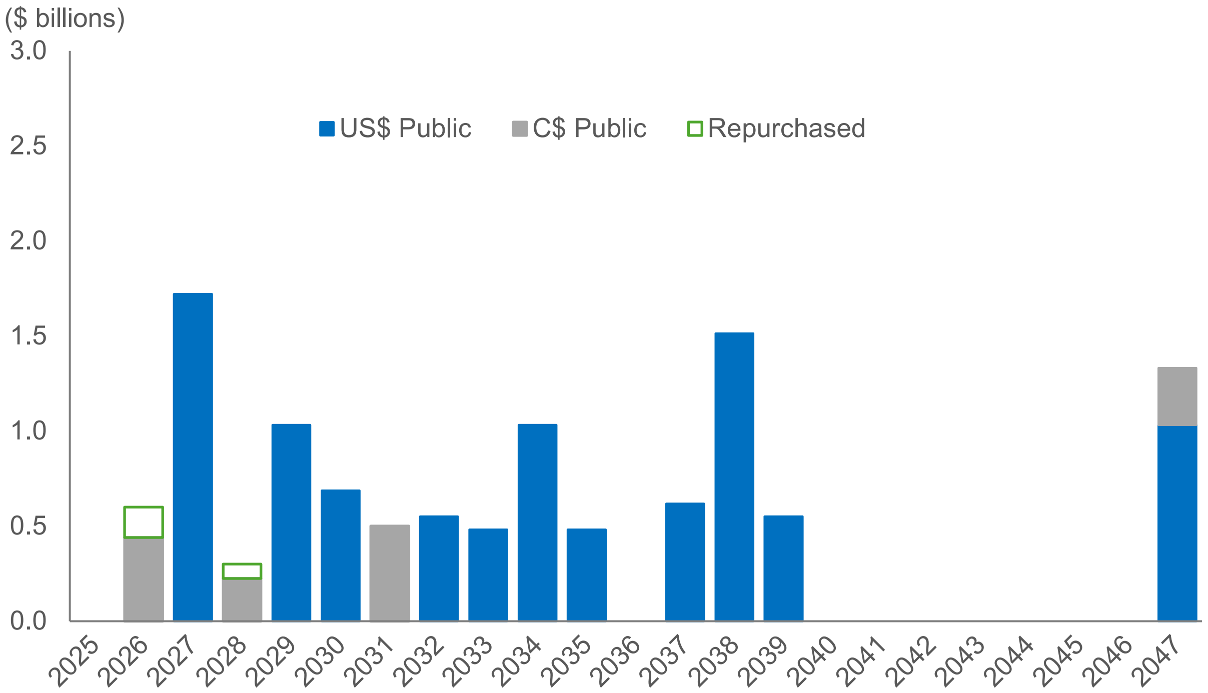
Revolving Credit Facilities	
June 2027(1)	$2,425 million
June 2028(1)	$2,425 million
June 2027(1)	$500 million
Operating Demand Facility	$100 million
Term Loans	
December 2027(1)	$4,000 million
Total	**$9,450 million**

DBRS	Moody's	Fitch
A (low) long-term	Baa1 long-term	BBB+ long-term
Negative outlook	Stable outlook	Stable outlook
R-1 short-term	P-2 short-term	F2 short-term

(1) Financial covenant on Credit Facilities is based on consolidated debt to book capital ratio to not exceed 0.65:1.00.
(2) Including committed and undrawn credit facilities, cash balances, cash equivalents and short-term investments.
Note: As at September 30, 2025.

Canadian Natural
Bond maturity profile

Balanced &
strategically built
debt maturities provide ample
flexibility



Note: US public debt converted to CAD at 1.3763 exchange rate as at September 30, 2025.

Unparalleled Assets – Conventional E&P

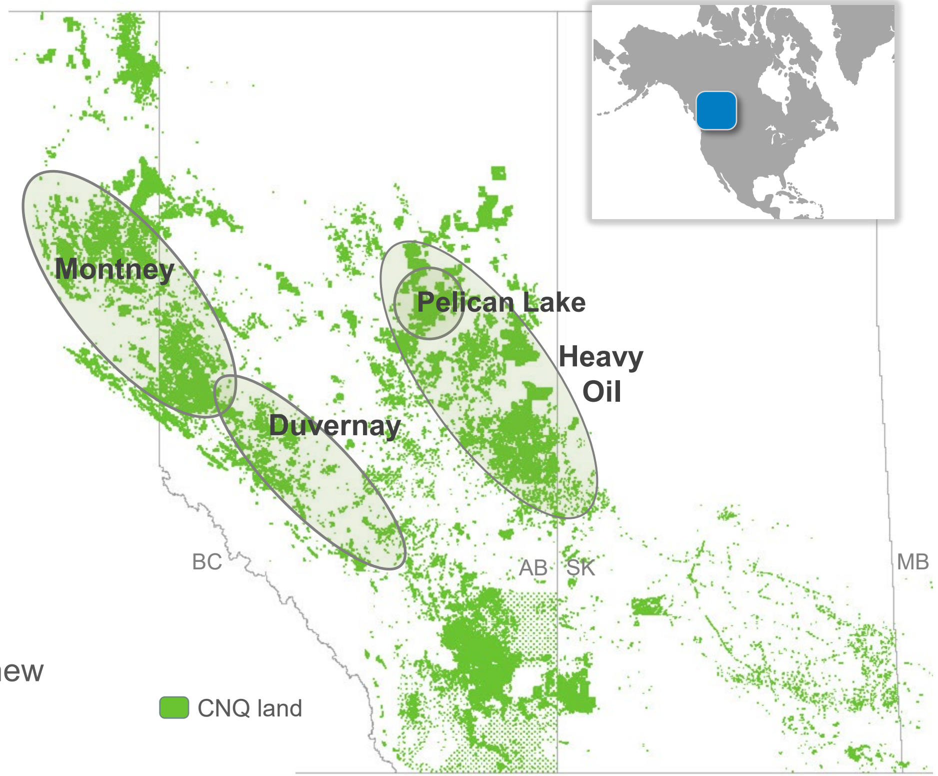
North America Conventional E&P
Asset overview

~715,000 BOE/d of production(1)
- ~290,000 bbl/d of production – largest in Canada
  - ~130,000 bbl/d heavy crude oil
  - ~160,000 bbl/d light crude oil & NGLs
- ~2.5 Bcf/d of production – 2nd largest in Canada

~6.6 billion BOE of 2P reserves(2)
- ~2.1 billion barrels of 2P reserves
- ~27.1 Tcf of 2P reserves
- Largest conventional E&P reserves in Canada

Extensive asset base
- ~25 million net acres
- >10,000 defined locations(3)
- Significant owned and operated infrastructure

Unparalleled assets create opportunity
- Technology evolution and expertise continue to unlock new value across our lands



(1) Annual 2025F production.
(2) Company gross total proved plus probable reserves at December 31, 2024.
(3) Assumes US$65/bbl WTI, US$12/bbl WCS differential, C$2.50/GJ AECO and US$1.00 to C$1.35 foreign exchange.

Primary Heavy Crude Oil Multilaterals

Technology advancements create new value on existing lands

Multilateral wells unlock areas that were historically unproductive

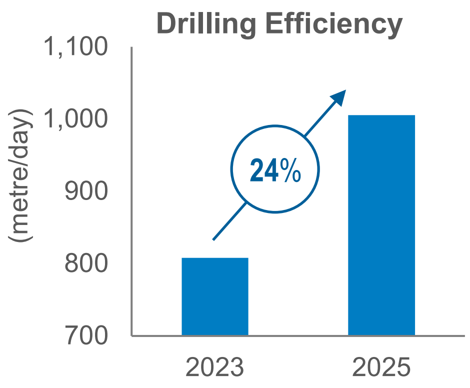
- >4,000 multilateral and slant locations in inventory(1)
- Payouts averaging <12 months

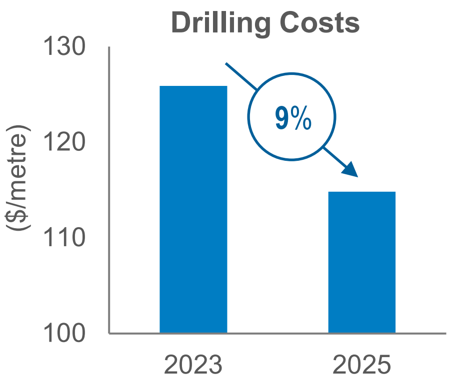
Improving the technology to increase margins

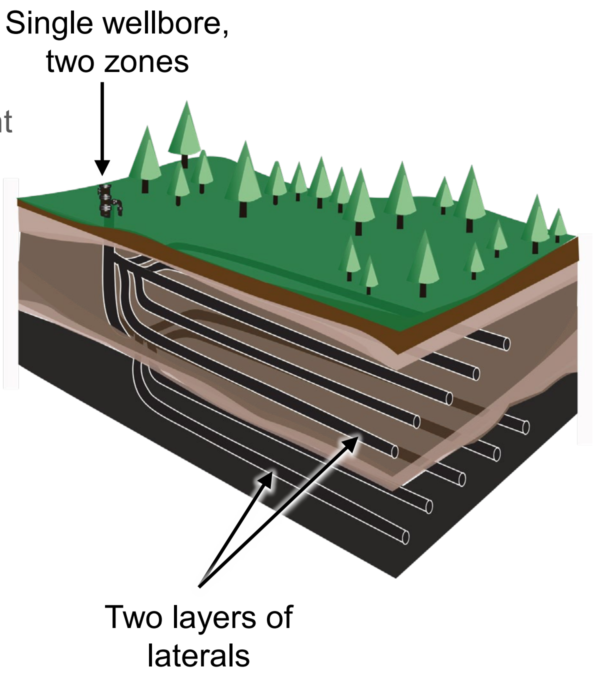
- Increasing well lengths = more reservoir capture for less capital, reduced footprint
- Average horizontal length per well in 2022 ~8,500m → 2025F ~11,000m

Innovative well designs lower costs and improve capital efficiency

- Stacked laterals in thick pay reduce drilling, completion and operating costs



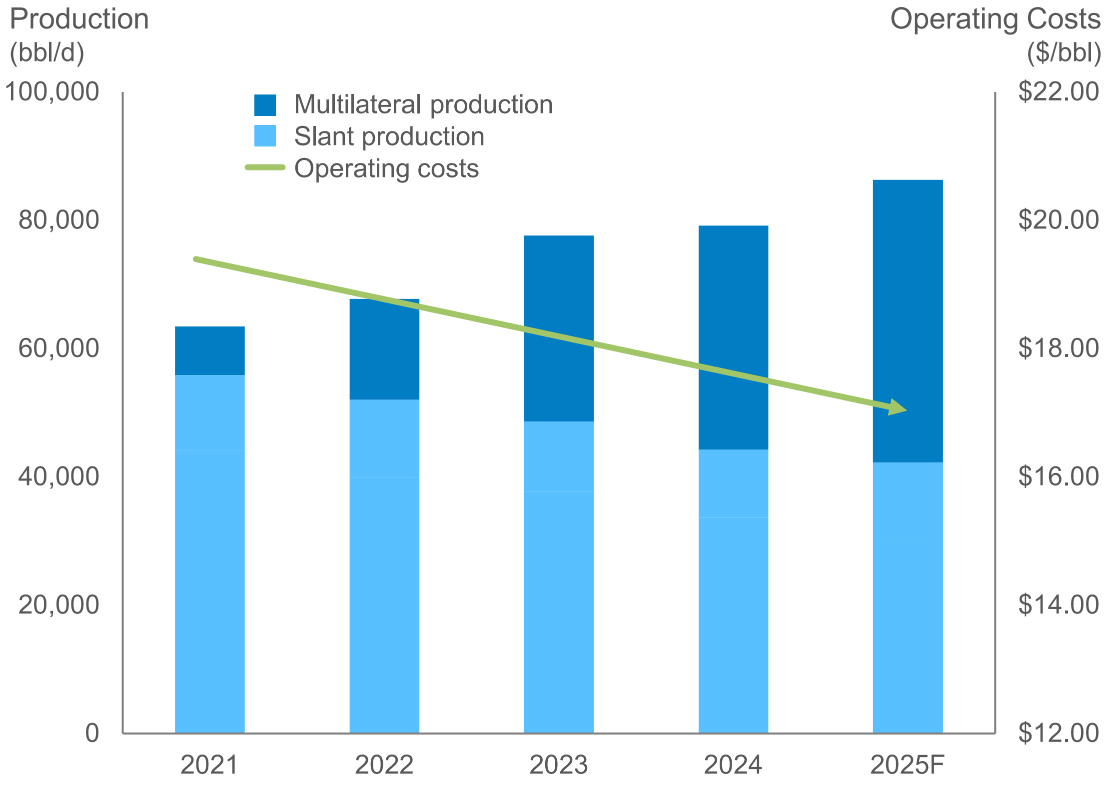




(1) Assumes US$65/bbl WTI, US$12/bbl WCS differential, C$2.50/GJ AECO and US$1.00 to C$1.35 foreign exchange.

Primary Heavy Crude Oil

Continuous improvement in multilateral technology & costs



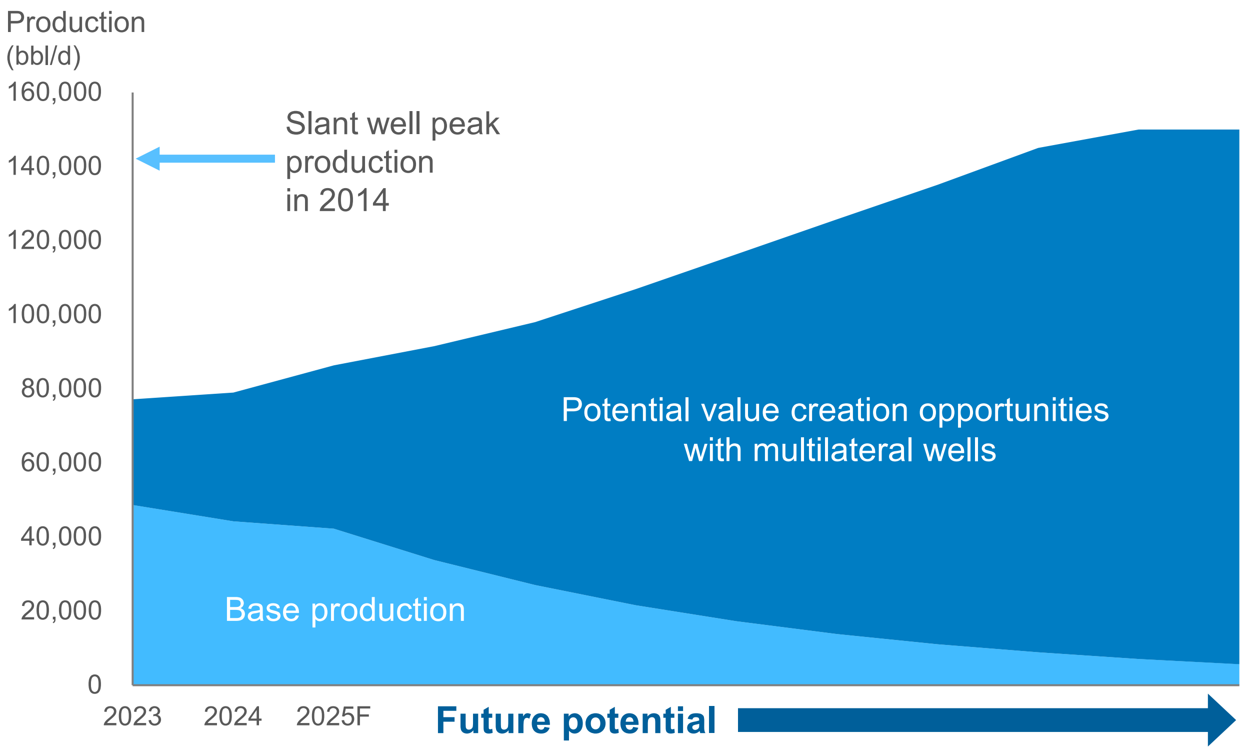
Grown multilateral production on existing asset base from ~7,500 bbl/d to **~45,000** bbl/d in 5 years

Multilateral production now represents **~50%** of total primary heavy crude oil production

~90% of primary heavy crude oil drilling in 2025F is multilateral wells versus ~45% in 2021

Primary Heavy Crude Oil

Production & value creation on existing assets through multilateral technology



Potential to **double production** with **multilateral** well technology on our **extensive** asset base of **~3.0** million net acres

Heavy Crude Oil

Pelican Lake & Driftwood core area – proven, expanding EOR technology

2025F production: ~43,000 bbl/d

Pelican Lake Polymer Flood – Wabiskaw A Formation

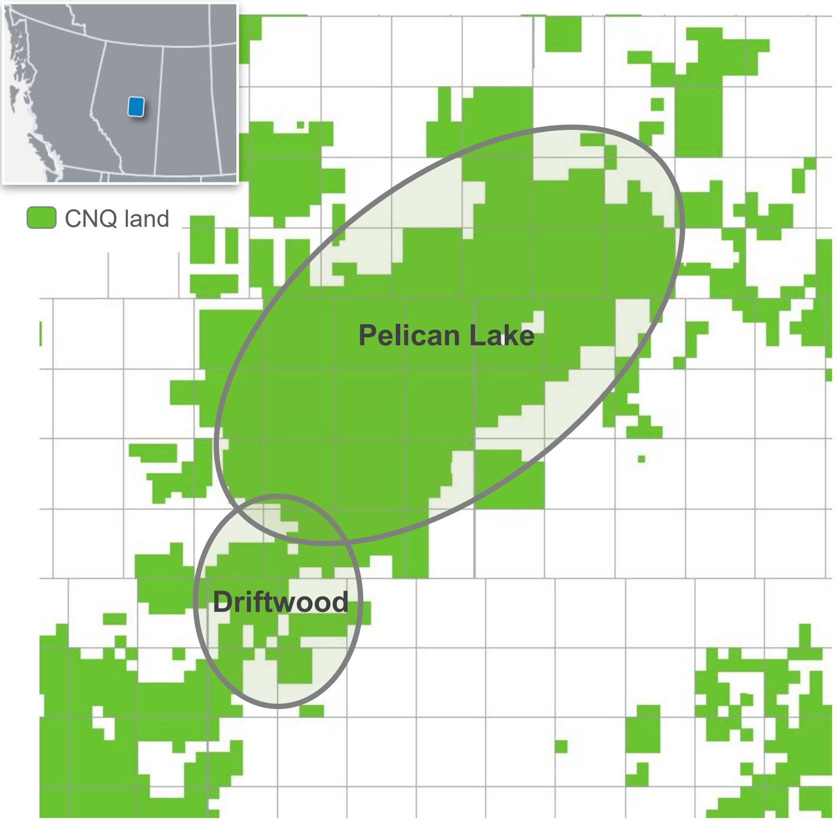
- North America's leading polymer flood
- Long life low decline asset
- ~4.4 billion barrels of Original Oil in Place
- >540 million barrels produced to-date

Driftwood Polymer Flood – Wabiskaw C Formation

- Leveraging our experience
- Polymer injection commenced in August 2025
- ~500 million barrels Original Oil in Place
- Short to medium-term growth of ~19,000 bbl/d

Increasing Recovery Factor

Primary	Pelican Lake Polymer Flood (today)	Pelican Lake / Driftwood Polymer Flood (target)
6%	12%	~28%



Montney

Premium light crude oil & liquids-rich natural gas

2025F Montney production: ~247,000 BOE/d

- ~1,140 MMcf/d and ~57,000 bbl/d

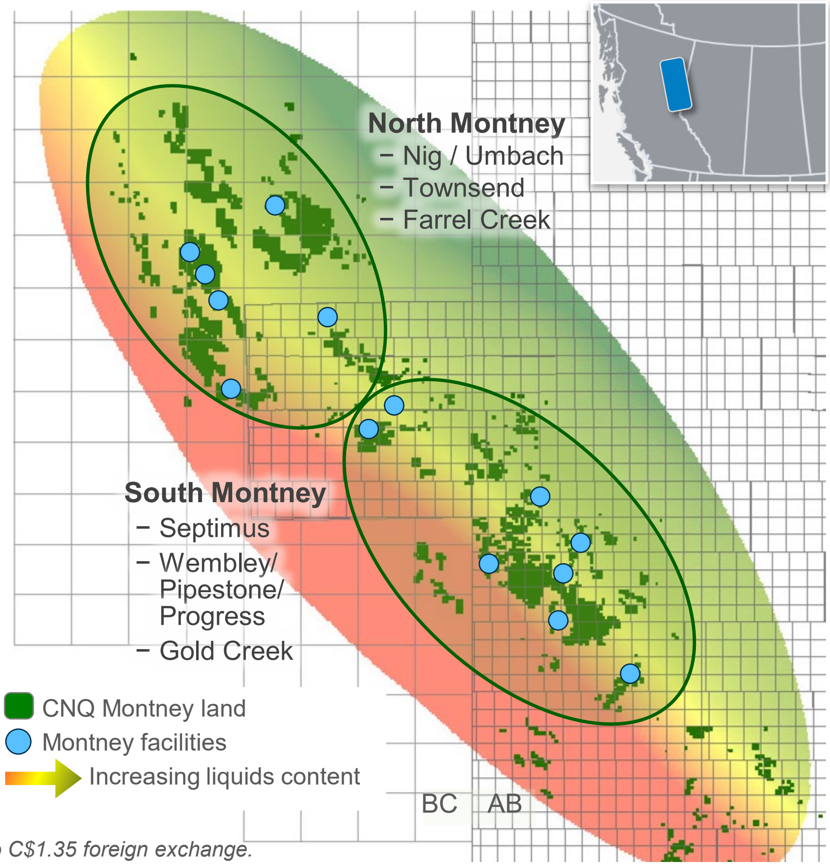
~1.65 million net acres of Montney rights

Extensive owned and controlled processing capacity

- ~1,560 MMcf/d net facility design capacity
- Available drill to fill capacity of ~420 MMcf/d

>3,000 defined locations(1)

- Flexible and scalable to respond to commodity prices
- Payouts averaging ~9 months(1)



(1) *Assumes US$65/bbl WTI, US$12/bbl WCS differential, C$2.50/GJ AECO and US$1.00 to C$1.35 foreign exchange.*

LARGE MONTNEY LAND BASE WITH EXTENSIVE LIQUIDS-RICH INVENTORY

Duvernay
Kaybob core area

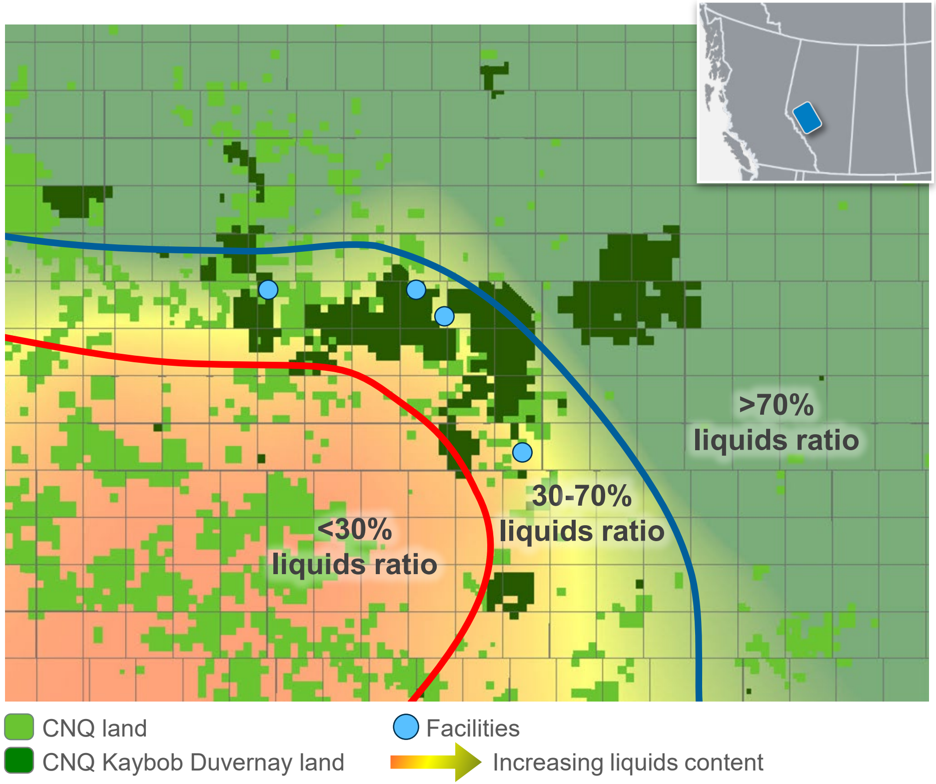
2025F production: ~60,000 BOE/d
- ~177 MMcf/d and ~30,000 bbl/d

Dedicated processing capacity enables growth
- Current net capacity of ~210 MMcf/d
- Option to increase capacity by 100 MMcf/d

~320,000 net acres of Duvernay rights

Premium light crude oil & liquids-rich natural gas asset
- 2025F average liquids content of ~50%
- ~300 locations defined inventory[1]
- Payouts averaging ~14 months

Continuous improvement drives value
- Reduced operating costs by 20% since acquiring asset
  - $7.60/BOE in Q3/25 compared to $9.52/BOE in Q1/25



(1) *Assumes US$65/bbl WTI, US$12/bbl WCS differential, C$2.50/GJ AECO and US$1.00 to C$1.35 foreign exchange.*

Canadian Natural

Unparalleled Assets – Thermal In Situ

Thermal In Situ Oil Sands
Asset overview

2025F production: ~274,000 bbl/d

- 100% working interest
- Long life low decline production

~5.2 billion barrels of 2P reserves(1)

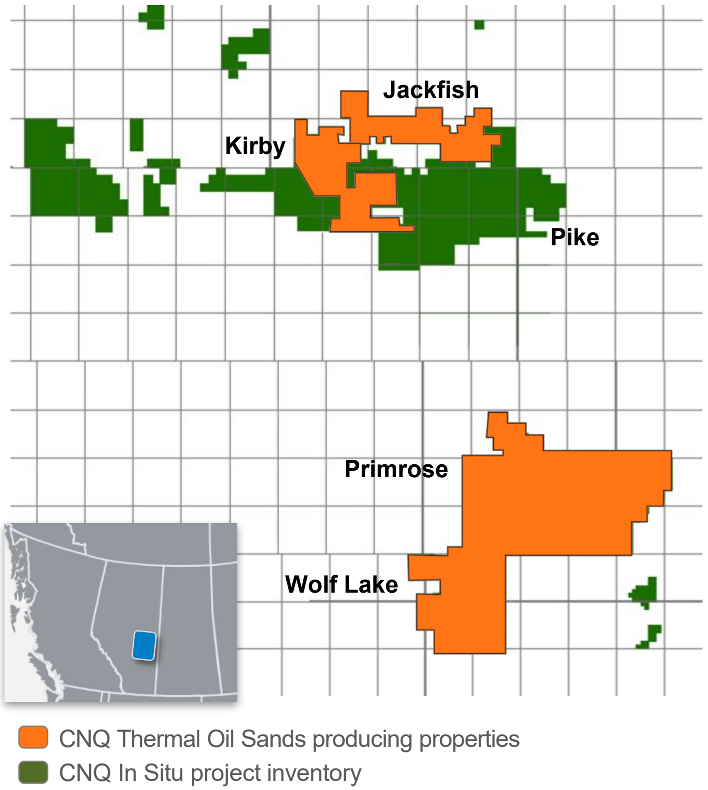
- 2nd largest 2P bitumen reserves in Canada

Highly capital efficient growth

- Facility capacity of ~340,000 bbl/d(2)
  - ~66,000 bbl/d available capacity

Leverage technology and innovation to enhance recovery and optimize costs

- Expertise in: Cyclic Steam Stimulation (CSS), Steam Assisted Gravity Drainage (SAGD), Steam Flood and Solvents
- Solvent SAGD pad at Kirby North



(1) Company gross total proved plus probable reserves at December 31, 2024.
(2) Includes Jackfish, Kirby and Primrose/Wolf Lake facility capacities.

Thermal In Situ Oil Sands

Primrose / Wolf Lake overview

2025F production: ~95,000 bbl/d

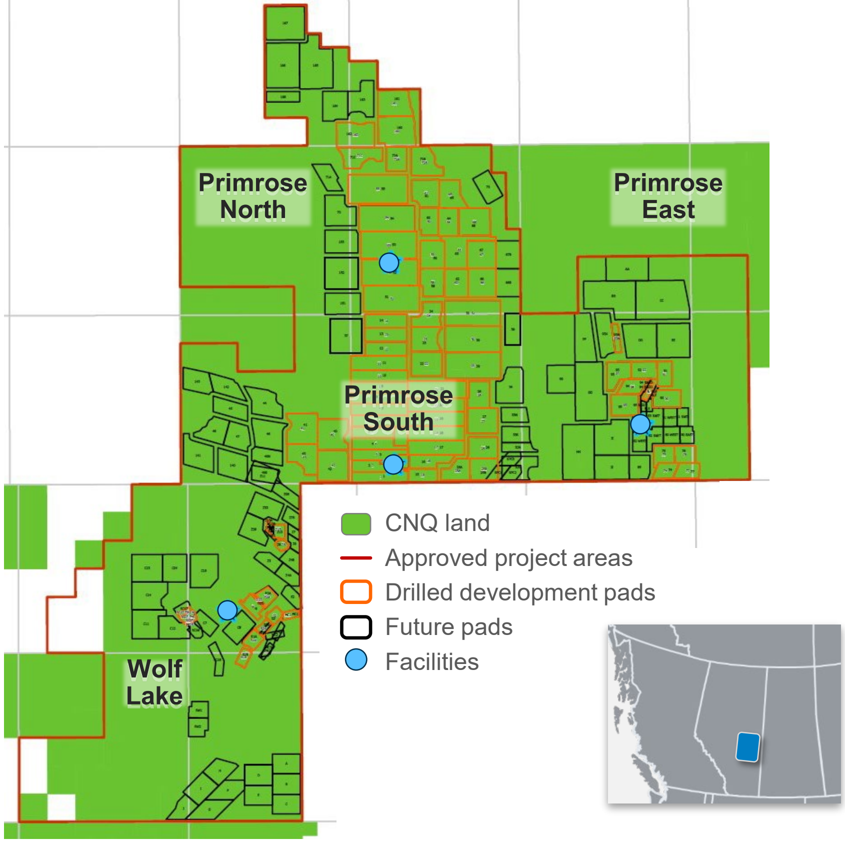
- Facility capacity: ~140,000 bbl/d
- Available drill to fill capacity: ~45,000 bbl/d

Low cost, low risk and repeatable CSS pad development

- 90 potential future pad additions[(1)]
- Recovery factors of up to ~65%
- Strong capital efficiency average of ~$10,000/bbl/d

Future potential growth opportunities

- Brownfield expansions ~40,000 bbl/d
  - Increases total facility capacity to ~180,000 bbl/d
- Potential solvent enhanced upside



(1) Assumes US$65/bbl WTI, US$12/bbl WCS differential, C$2.50/GJ AECO and US$1.00 to C$1.35 foreign exchange

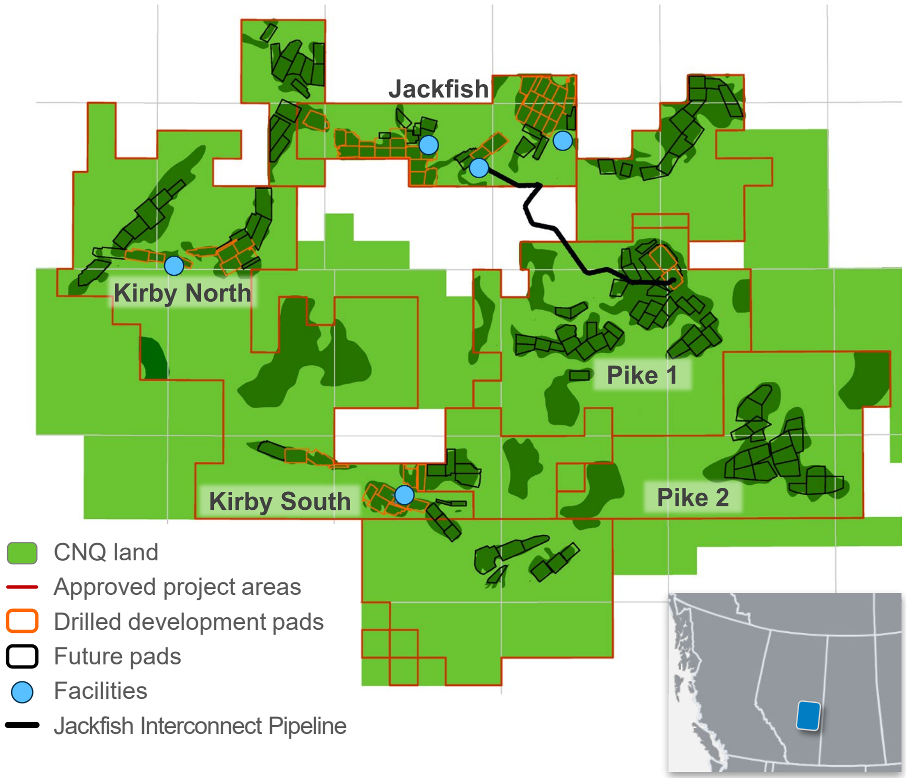
Thermal In Situ Oil Sands
Kirby / Jackfish / Pike SAGD overview

2025F production: ~177,000 bbl/d
- Facility capacity: ~200,000 bbl/d(1)
- Available drill to fill capacity: ~23,000 bbl/d

Economies of scale lower costs across land base
- Five central processing facilities
- Pike 1 pads tied into Jackfish

Low cost, low risk, repeatable SAGD pad development
- 110 potential future pad additions(2)
- Recovery factors of up to 70%
  - Strong capital efficiency average of ~$10,000/bbl/d

Future growth potential opportunities
- Brownfield expansion at Jackfish of ~30,000 bbl/d
- Greenfield expansion at Pike 2 of ~70,000 bbl/d



(1) Includes Jackfish 1, 2 & 3, Kirby South and Kirby North facilities.
(2) Assumes US$65/bbl WTI, US$12/bbl WCS differential, C$2.50/GJ AECO and US$1.00 to C$1.35 foreign exchange.

Thermal In Situ Oil Sands

Medium-term value creation opportunities

Jackfish
Brownfield expansion

	Capital Estimate
Year 1	$0.02 - $0.02 B
Year 2	$0.18 - $0.19 B
Year 3	$0.20 - $0.24 B
Year 4	$0.20 - $0.24 B
Year 5	$0.05 - $0.06 B
Total Capital	$0.65 - $0.75 B
Capital Efficiency	$22,000 - $25,000/bbl/d
Growth	**+30,000** bbl/d

Adding
high value,
low decline
production of
~100,000 bbl/d
through highly
capital efficient
expansion projects

Pike 2
Greenfield expansion

	Capital Estimate
Year 1	$0.02 - $0.02 B
Year 2	$0.28 - $0.30 B
Year 3	$0.40 - $0.48 B
Year 4	$0.70 - $0.70 B
Year 5	$0.70 - $0.80 B
Year 6	$0.40 - $0.50 B
Total Capital	$2.50 - $2.80 B
Capital Efficiency	$35,000 - $40,000/bbl/d
Growth	**+70,000** bbl/d

Note: Execution of expansion projects are independent of each other.

Unparalleled Assets – Oil Sands Mining & Upgrading

Canadian Natural

Oil Sands Mining & Upgrading
Asset overview

World-class Oil Sands Mining & Upgrading assets

Total capacity of ~592,000 bbl/d(1)

- ~90% of which is high value SCO

No decline, no reservoir risk

- ~8.3 billion barrels of 2P reserves(2)
  - Represents ~41% of total Company 2P reserves
  - 2P reserve life index of ~47 years(2)

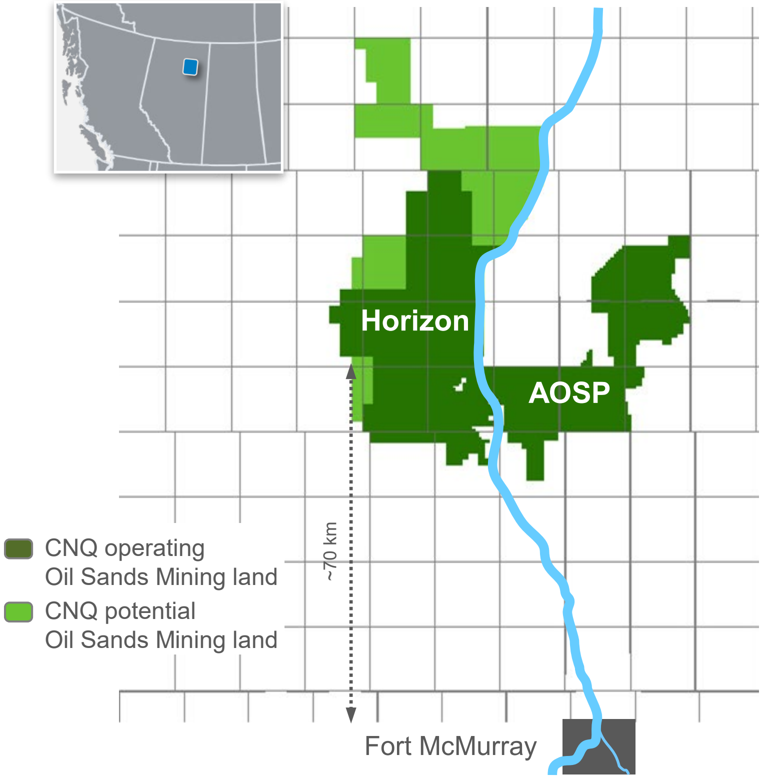
Significant resource in place

- ~20.4 billion barrels BIIP(3)

Industry leading operating costs

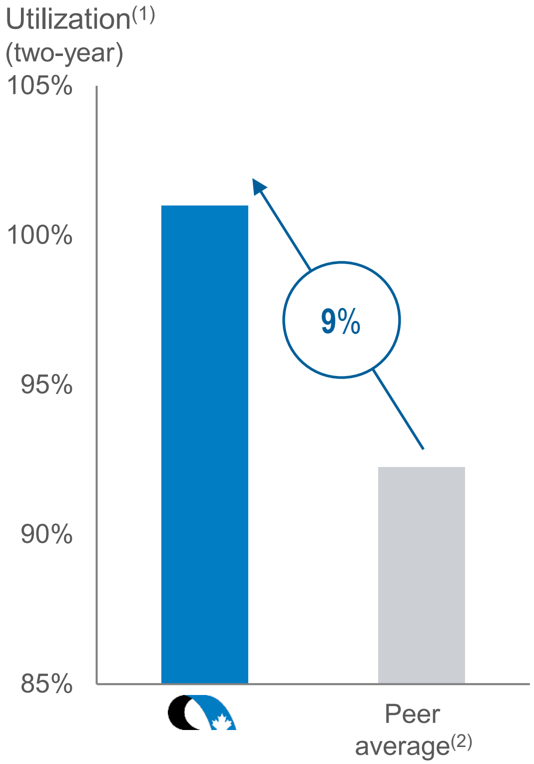
Low maintenance capital

Focused on safety, reliability and high utilization



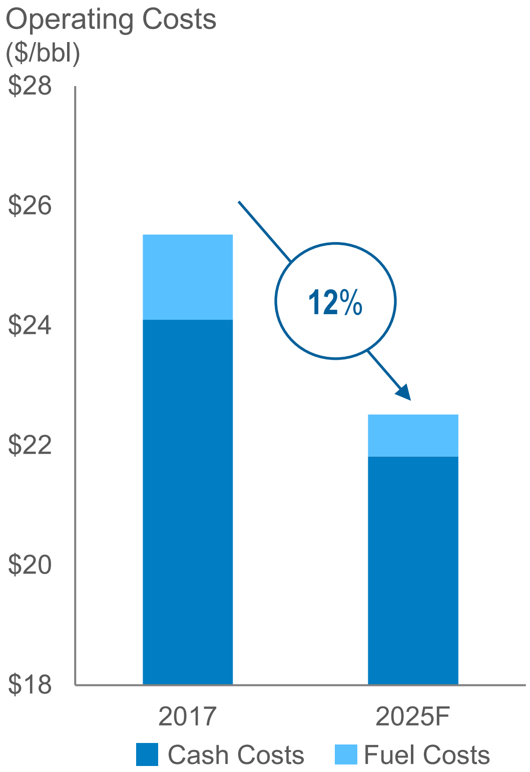
(1) Reflects 100% interest in the Albian mines and is based on a two-year average to reflect the biannual turnaround schedule at Horizon.
(2) Company gross total proved plus probable reserves at December 31, 2024.
(3) Mineable Bitumen Initially-in-Place (BIIP).

Oil Sands Mining & Upgrading
Leading utilization & operating costs



~9%
higher utilization than peer average

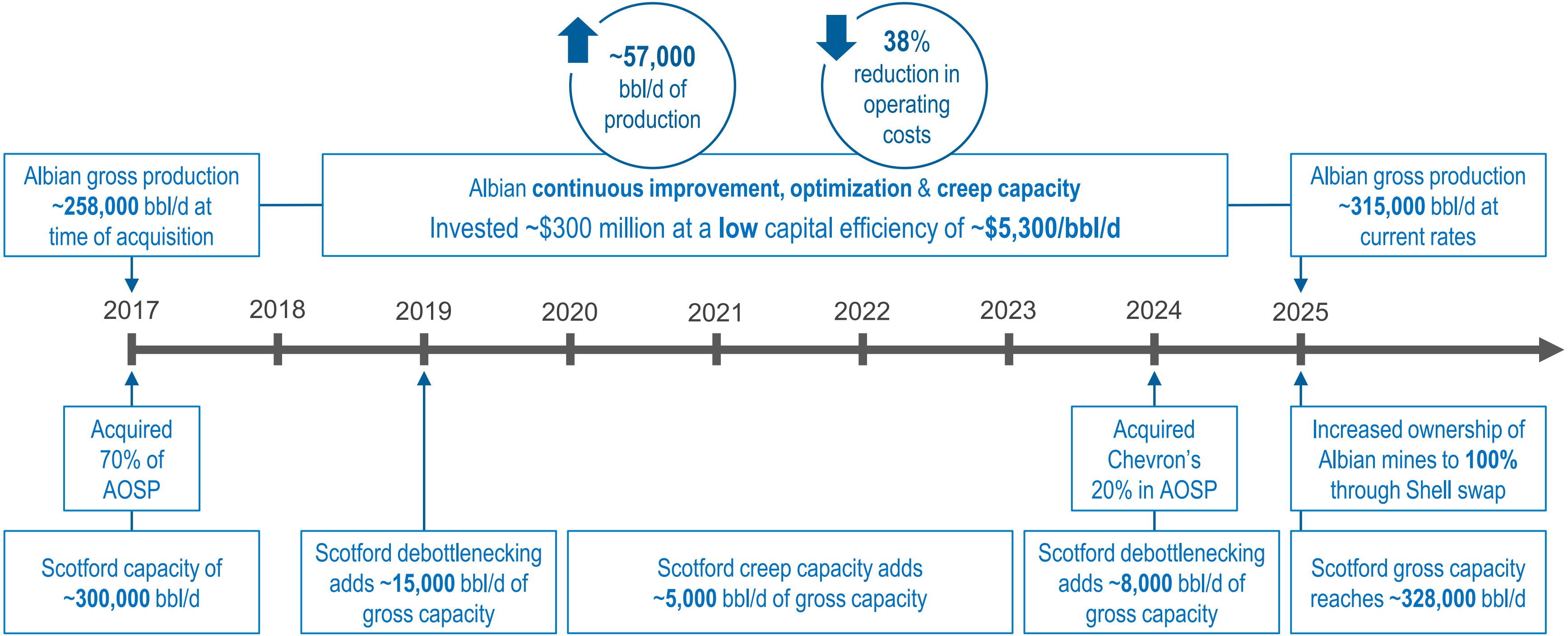
~12%
reduction in annual operating costs since acquisition of AOSP and completion of Horizon Phase 3 in 2017



(1) Trailing two-year utilization, up to June 2025. Source: TD Cowen "Mine Your Own Business" report dated October 3, 2025.
(2) Peer average includes: Kearl (IMO), Base (SU), Fort Hills (SU), and Syncrude (SU).

AOSP Mine Value Creation

Strategic & cultural expertise drives long-term shareholder value



Canadian Natural

CONSISTENT INDUSTRY LEADING VALUE GROWTH SINCE 2017 ACQUISITION

AOSP Swap Transaction – Value of Owning 100% of Albian Mines

Increased ownership benefits Horizon & Albian mines

Mine integration → Increases efficiencies → Reduces costs

Increases Oil Sands Mining production by ~5%

Additional cash flow and shareholder returns

Allows increased utilization of equipment by site sharing

- Heavy-haul trucks, shovels, dozers, cranes and other support equipment
- Results in annual savings of ~$30 million per year

Combined inventory warehousing

- Eliminates redundant inventory
- Results in one time savings of ~$30 million

Full benefit of future cost reductions and synergies

Enhances value of future growth projects

- Additional debottleneck opportunities

~31,000 bbl/d
of additional bitumen production annually

$200 to **$300** million
in additional annual cash flow

~$30 million annual savings
~$30 million one-time savings

INCREASED OWNERSHIP STREAMLINES MINE PLANNING & PRODUCTION GROWTH

Horizon Value Creation

Value added through creep capacity & continuous improvement

Capacity increases to **~250,000** bbl/d following the completion of Phase 2/3, which added production of **~170,000** bbl/d

Continuous improvement & optimization

Capacity increases to **~264,000**(1) bbl/d following the completion of the reliability enhancement project

First year without a planned turnaround adding **~28,000** bbl/d resulting in production of **~275,000** bbl/d

2017 2018 2019 2020 2021 2022 2023 2024 2025

~25,000 bbl/d of production

10% reduction in operating costs

Invested ~$950 million at a **low** capital efficiency of **~$38,000/bbl/d**

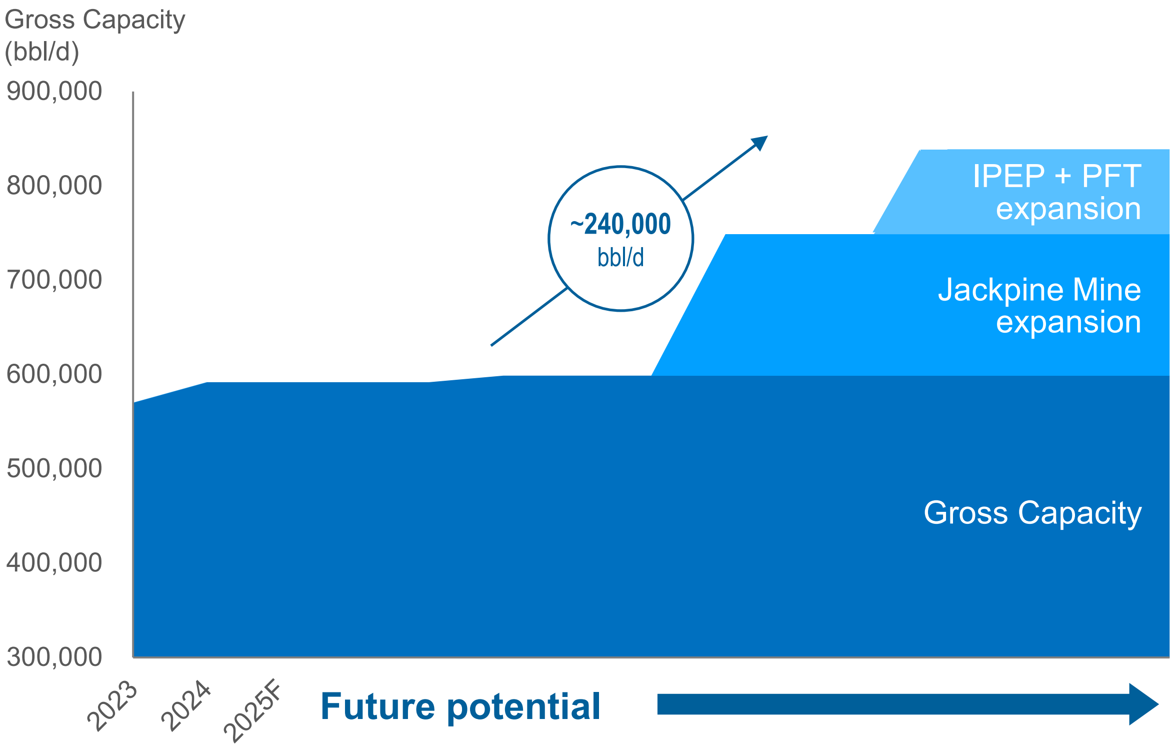
(1) 14,000 bbl/d of increased capacity based on a 2-year period.

Oil Sands Mining & Upgrading

Long-term value creation opportunity – production growth

Significant
zero decline
production growth
opportunities

~840,000 bbl/d
total gross SCO
& bitumen capacity
potential



SIGNIFICANT OIL SANDS MINING GROWTH POTENTIAL WITHOUT UPGRADER EXPANSION

Oil Sands Mining & Upgrading

Long-term value creation opportunities

Albian
JPM expansion

	Capital Estimate
Year 1	$0.2 - $0.3 B
Year 2	$1.0 - $1.2 B
Year 3	$1.8 - $2.1 B
Year 4	$2.0 - $2.3 B
Year 5	$2.3 - $2.7 B
Year 6	$0.2 - $0.4 B
Total Capital	$7.5 - $9.0 B

Capital efficiency $50,000 - $60,000/bbl/d

Growth	**+150,000** bbl/d

Adding **high value, zero decline** production of **~240,000** bbl/d through highly capital efficient expansion projects

Horizon
PFT & IPEP expansion

	Capital Estimate
Year 1	$0.1 - $0.2 B
Year 2	$0.1 - $0.2 B
Year 3	$0.2 - $0.3 B
Year 4	$0.5 - $0.6 B
Year 5	$1.1 - $1.3 B
Year 6	$1.4 - $1.6 B
Year 7	$1.1 - $1.3 B
Total Capital	$4.5 - $5.5 B

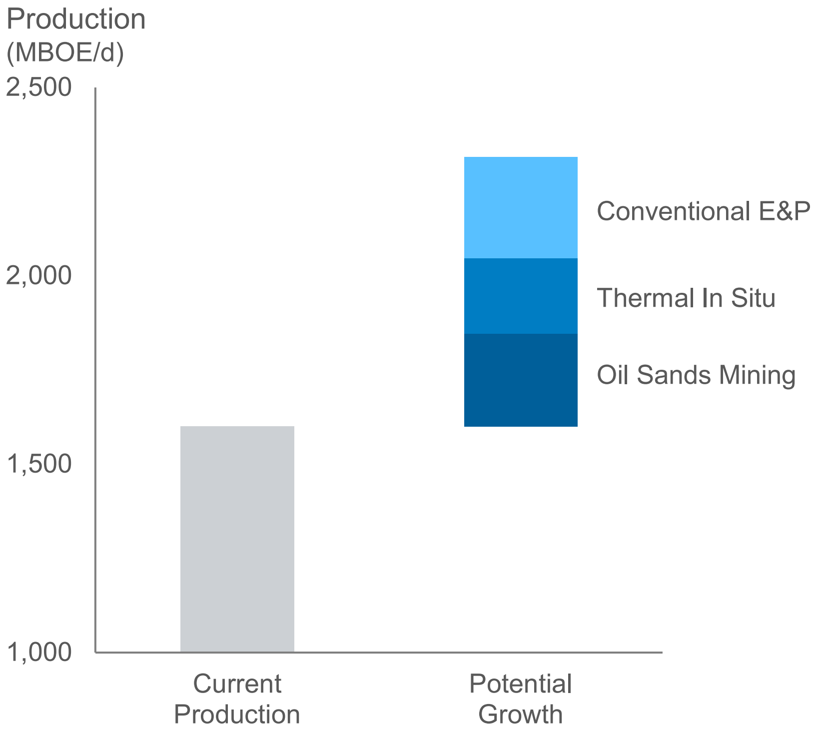
Capital efficiency $50,000 - $60,000/bbl/d

Growth	**+90,000** bbl/d

Note: Execution of expansion projects are independent of each other.

Canadian Natural Growth Potential
Total development potential

~745,000 BOE/d(1)
of future
growth potential



(1) Assumes US$65/bbl WTI, US$12/bbl WCS differential, C$2.50/GJ AECO and US$1.00 to C$1.35 foreign exchange.
Note: See Advisory for cautionary statements and definitions.

Canadian Natural
Unparalleled Assets summary

Conventional E&P

- 2P reserves of **~6.6 billion BOE** and a RLI of ~35 years(1)
- 2025F production of **~715,000** BOE/d
- Production supported by decades of inventory and reserves
- Growth potential of **~295,000** BOE/d

Thermal In Situ

- 2P reserves of **~5.2 billion barrels** and a RLI of ~56 years(1)
- 2025F production of **~274,000** bbl/d
- Long life low decline production
- Growth potential of **~210,000** bbl/d

Oil Sands Mining & Upgrading

- 2P reserves of **~8.3 billion barrels** and a RLI of ~47 years(1)
- 2025F production of **~564,000** bbl/d
- Long life no decline SCO production
- Growth potential of **~240,000** bbl/d

(1) Company gross total proved plus probable reserves at December 31, 2024.

Environment
Land management

Photo: Canadian Natural planted its 5 millionth reclamation tree on September 24, 2025 at our Oil Sands Mining assets.

Abandoned ~11,300 inactive wells
in five years, from 2020 to 2024

~5.0 million trees planted
in our oil sands mining operations
since 2009

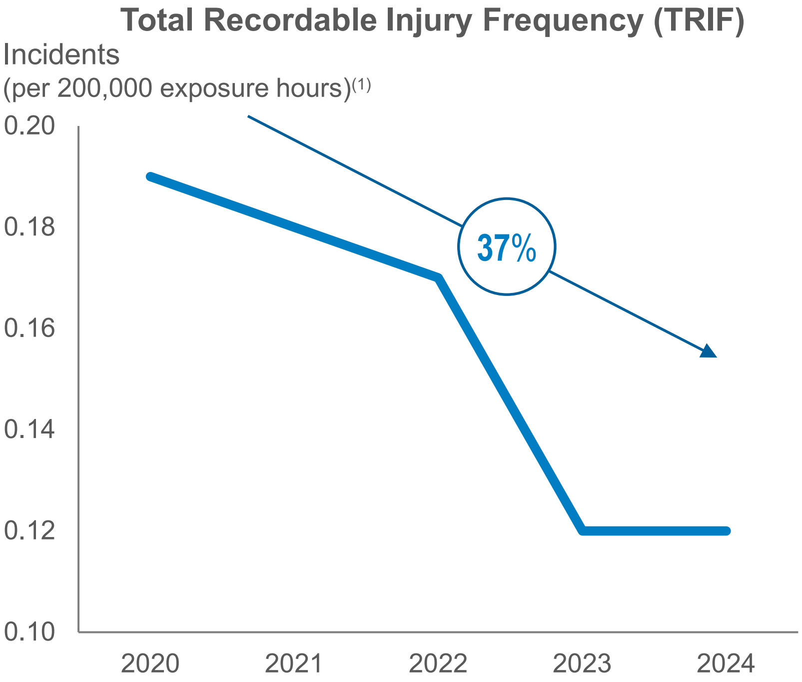
~5.9 million trees planted to date
in our NA E&P operations

~17,600 hectares reclaimed in
NA E&P since 2016

~1,300 reclamation certificates submitted
in NA E&P, exceeding the
2024 goal of >1,099/year

Safety

Frontline driven incident prevention



Comprehensive frontline driven **safety** management system

~101,800 Worksite Safety Observations in 2024

70% reduction in Lost Time Incident (LTI) frequency since 2020

Action plans focus on top causes of injuries through:

- Worksite Safety Observations
- Proactive safety audits
- Coaching frontline supervisors
- Safety Excellence/Mission Statement Meetings

(1) Revised to align with Energy Safety Canada's methodology.

TARGET: NO HARM TO PEOPLE, NO SAFETY INCIDENTS

Carbon Capture & Sequestration / Storage Technology

Canadian Natural today

Quest

Horizon

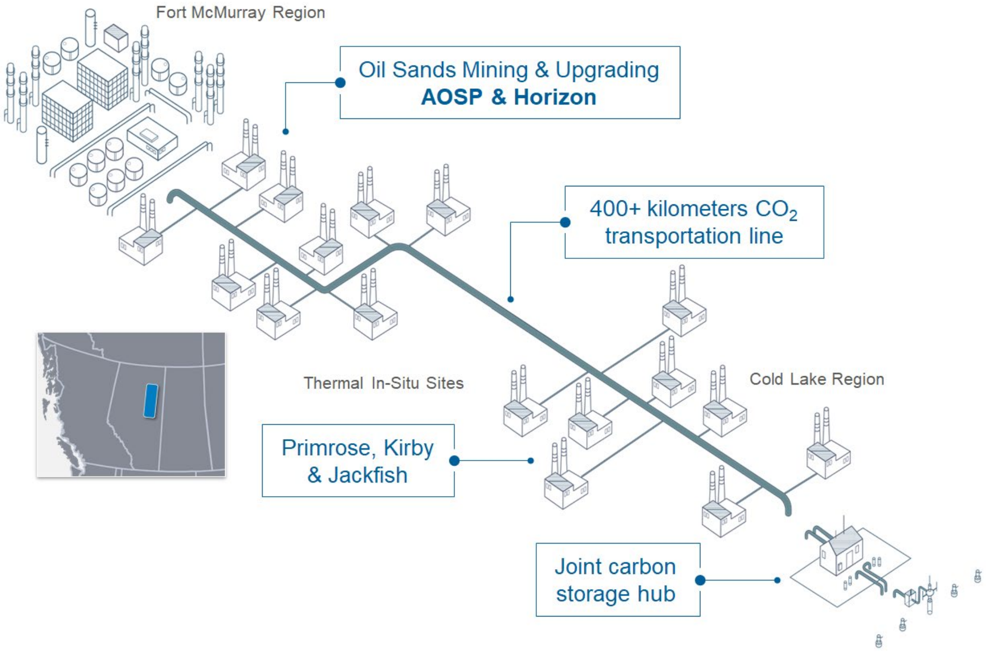
	Capture Capacity (tonnes/year)
Horizon	~0.4 million
Quest[(2)]	~1.1 million
NWR[(3)]	~1.2 million
Total	~2.7 million

A **global leader** in CO_2 capture & sequestration[(1)]

A portion of the CO_2 for these projects is captured from hydrogen manufacturing plants, producing "blue hydrogen"

(1) 6th largest globally, per the Global CCS Institute.
(2) Canadian Natural is an 80% working interest owner in Quest.
(3) Canadian Natural is a 50% owner in North West Redwater (NWR).

Pathways Alliance
Proposed CO_2 transportation line



Highlights

- Front-end engineering and design study on main transportation line and connecting pipelines has been completed
- Filed key regulatory applications for the Pathways CO_2 transportation network
- >10,000 hours of environmental field work completed since the beginning of the program to support regulatory applications
- Engagement and consultation with 25 Indigenous groups along the pipeline corridor

Canadian Natural

PROVEN • EFFECTIVE • STRATEGY

Advisory

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "focus", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration", or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to the Company's strategy or strategic focus, capital budget, expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, forecast and anticipated abandonment expenditures, income tax expenses, and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, including the strength of the Company's balance sheet, the sources and adequacy of the Company's liquidity, and the flexibility of the Company's capital structure, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), the Primrose thermal oil projects ("Primrose"), the Pelican Lake water and polymer flood projects ("Pelican Lake"), the Kirby thermal oil sands project ("Kirby"), the Jackfish thermal oil sands project ("Jackfish") and the North West Redwater bitumen upgrader and refinery; construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs"), or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market; the maintenance of the Company's facilities and any expected return to service dates; the construction, expansion, or maintenance of third-party facilities that process the Company's products; the abandonment and decommissioning of certain assets and the timing thereof; the development and deployment of technology and technological innovations; the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term; and the materiality of the impact of tax interpretations and litigation on the Company's results, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives, or expectations upon which they are based will occur. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas, and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates, and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance, or achievements of the Company to be materially different from any future results, performance, or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+"), the impact of conflicts in the Middle East and in Ukraine, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, natural gas and NGLs prices; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; changes and uncertainties in the international trade environment, including with respect to tariffs, export restrictions, embargoes, and key trade agreements (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded); uncertainty in the regulatory framework governing greenhouse gas emissions including, among other things, financial and other support from various levels of government for climate related initiatives and potential emissions or production caps; civil unrest and political uncertainty, including changes in government, actions of or against terrorists, insurgent groups, or other conflict including conflict between states; the ability of the Company to prevent and recover from a cyberattack, other cyber-related crime, and other cyber-related incidents; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling, and other equipment; ability of the Company to complete capital programs; the Company's ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting, or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in the mining, extracting, or upgrading the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; changes to future abandonment and decommissioning costs, actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium-, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the impact of legal proceedings to which the Company is party; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state, and local laws and regulations such as restrictions on production, the imposition of tariffs, embargoes, or export restrictions on the Company's products (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded), changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this document could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity, and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this document, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

Advisory *(Continued)*

Special Note Regarding Common Share Split and Comparative Figures

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

Special Note Regarding Amendments to the *Competition Act* (Canada)

On June 20, 2024, amendments to the *Competition Act* (Canada) came into force with the adoption of Bill C-59, *An Act to Implement Certain Provisions of the Fall Economic Statement* which impact environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the Competition Act's deceptive marketing practices provisions. These amendments include substantial financial penalties and, effective June 20, 2025, a private right of action which permits private parties to seek an order from the Competition Tribunal under the deceptive marketing practices provisions. Uncertainty surrounding the interpretation and enforcement of this legislation may expose the Company to increased litigation and financial penalties, the outcome and impacts of which can be difficult to assess or quantify and may have a material adverse effect on the Company's business, reputation, financial condition, and results.

Special Note Regarding Currency, Financial Information and Production

This document should be read in conjunction with the Company's MD&A and unaudited interim consolidated financial statements (the "financial statements") for the three and nine months ended September 30, 2025, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2024. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's MD&A and financial statements for the three and nine months ended September 30, 2025 have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf: 1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf: 1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf: 1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this document, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented for information purposes only.

Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2024, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information in such Annual Information Form and on the Company's website does not form part of and is not incorporated by reference in the Company's MD&A, dated November 5, 2025.

Special Note Regarding Non-GAAP and Other Financial Measures

This document includes references to Non-GAAP and Other Financial Measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this this document and the Company's MD&A and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2025 dated November 5, 2025.

Breakeven WTI Price

The breakeven WTI price is a supplementary financial measure that represents the equivalent US dollar WTI price per barrel where the Company's adjusted funds flow is equal to the sum of maintenance capital and dividends. The Company considers the breakeven WTI price a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. The breakeven WTI price incorporates the non-GAAP financial measure adjusted funds flow as reconciled in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A. Maintenance capital is a supplementary financial measure that represents the capital required to maintain annual production at prior period levels.

Capital Budget

Capital budget is a forward-looking non-GAAP financial measure. The capital budget is based on net capital expenditures (non-GAAP financial measure) and includes acquisition capital related to a number of acquisitions for which agreements between parties have been reached as at the time of the Company's 2025 budget press release on January 9, 2025. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on net capital expenditures.

The 2025 capital forecast reflects forecasted net capital expenditures, before abandonment expenditures related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these forecasted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries in Canada and the UK portion of the North Sea. The Company is eligible to recover interest on related to tax recoveries in the North Sea.

Advisory *(Continued)*

Capital Efficiency

Capital efficiency is a supplementary financial measure that represents the capital spent to add new or incremental production divided by the current rate of the new or incremental production. It is expressed as a dollar amount per flowing volume of a product ($/bbl/d or $/BOE/d). The Company considers capital efficiency a key measure in evaluating its performance, as it demonstrates the efficiency of the Company's capital investments.

Free Cash Flow Allocation Policy

Free cash flow is a non-GAAP financial measure. The Company considers free cash flow a key measure in demonstrating the Company’s ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders and to repay or maintain net debt levels, pursuant to the free cash flow allocation policy.

The Company’s free cash flow is used to determine the targeted amount of shareholder returns after dividends. The amount allocated to shareholders varies depending on the Company’s net debt position.

Free cash flow is calculated as adjusted funds flow less dividends on common shares, net capital expenditures and abandonment expenditures. The Company targets to manage the allocation of free cash flow on a forward looking annual basis, while managing working capital and cash management as required.

Up to October 2024, before the announcement of the Chevron acquisition, the Company was targeting to allocate 100% of its free cash flow in 2024 to shareholder returns.

In October 2024, with the announcement of the Chevron acquisition, the Board of Directors adjusted the allocation of free cash flow as follows:

- 60% of free cash flow to shareholder returns and 40% to the balance sheet until net debt reaches $15 billion.
- When net debt is between $12 billion and $15 billion, free cash flow allocation will be 75% to shareholder returns and 25% to the balance sheet.
- When net debt is at or below $12 billion, free cash flow allocation will be 100% to shareholder returns.

The Company's free cash flow for the three months ended September 30, 2025 and comparable periods is shown below:

	Three Months Ended		
($ millions)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024
Adjusted funds flow [(1)]	**$ 3,920**	$ 3,262	$ 3,921
Less: Dividends on common shares	**1,228**	1,233	1,118
Net capital expenditures[(2)]	**2,124**	1,915	1,349
Abandonment expenditures	**189**	193	204
Free cash flow	**$ 379**	$ (79)	$ 1,250

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2025 dated November 5, 2025.

(2) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2024. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2025 dated November 5, 2025.

Long-term Debt, net

Long-term debt, net (also referred to as net debt) is a capital management measure that is calculated as current and long-term debt less cash and cash equivalents.

($ millions)	**Sep 30 2025**	Jun 30 2025	Dec 31 2024	Sep 30 2024
Long-term debt	**$ 17,268**	$ 17,081	$ 18,819	$ 10,029
Less: cash and cash equivalents	**113**	102	131	721
Long-term debt, net	**$ 17,155**	$ 16,979	$ 18,688	$ 9,308

Advisory *(Continued)*

Cautionary Statement

Project progress and financial results are dependent upon economic and regulatory conditions, commodity prices, global economic factors, project sanction and capital allocation.

Pelican Lake & Driftwood

~4.9 billion barrels of Original Oil in-place is comprised of:

- 360 million barrels of total proved plus probable reserves at December 31, 2024 that were evaluated in accordance with COGEH standards by an Independent Qualified Reserves Evaluator
- 540 million barrels of produced oil to December 31, 2024
- Development of remaining volume is subject to company final investment decisions
- All values are company gross

Thermal In Situ Oil Sands Overview – Clearwater, McMurray, Bluesky, Grand Rapids and Grosmont Formations

~126 billion barrels of Discovered Bitumen Initially-in-place is comprised of:

- 5.2 billion barrels of total proved plus probable reserves at December 31, 2024 that were evaluated in accordance with COGEH standards by an Independent Qualified Reserves Evaluator
- 1.5 billion barrels of produced Bitumen to December 31, 2024
- Development of remaining volume is subject to company final investment decisions
- A portion of remaining volume may not be recoverable with current technology
- All values are company gross

Oil Sands Mining & Upgrading

~20.4 billion barrels of Mineable Bitumen Initially-in-place is comprised of:

- 8.9 billion barrels of Bitumen associated with 8.3 billion barrels of total proved plus probable SCO reserves at December 31, 2024 that were evaluated in accordance with COGEH standards by an Independent Qualified Reserves Evaluator
- 2.2 billion barrels of produced Bitumen to December 31, 2024
- Development of remaining volume is subject to company final investment decisions
- A portion of remaining volume may not be recoverable with current technology
- All values are company gross

Definitions

CAGR – Compound Annual Growth Rate – the compounded growth rate for a specific value on an annual basis in a defined time range.

Enterprise Value – market capitalization plus the Company's net total liabilities.

Estimated Ultimate Recovery (EUR) – Estimated Ultimate Recovery is the amount of oil and natural gas expected to be economically recovered from a well, reservoir or field by the end of its producing life.

Free Cash Flow Yield – Free Cash Flow divided by the Company's market capitalization at a given point in time.

Market Capitalization (Market Cap) – outstanding common shares multiplied by the Company's share price at a given point of time.

Maintenance Capital – net capital expenditures required to maintain flat production year over year.

Advisory *(Continued)*

Pricing Assumptions[1]	2024	2025F	2026B
Strip			
WTI US$/bbl	$ 75.72	$ 64.97	$ 60.00
AECO C$/GJ	$ 1.36	$ 1.76	$ 3.00
SCO Diff/(Prem) US$/bbl	$ 0.63	$ 0.37	$ 0.45
WCS Differential US$/bbl	$ 14.73	$ 11.16	$ 12.00
Average FX 1.00 US$ = X C$	$ 1.370	$ 1.397	$ 1.380

(1) Based on Strip and forecasted pricing as of October 28, 2025.

Glossary of Terms

AECO – Alberta Energy Company (benchmark pricing)

AOSP – Athabasca Oil Sands Project

BOE – barrels of oil equivalent

BBL – barrels of oil

Bcf – billion cubic feet

CCS – carbon capture and storage

CCUS – carbon capture, utilization and storage

CSS – cyclic steam stimulation

CO_2e – Carbon Dioxide equivalent

E&P – exploration and production

EOR – enhanced oil recovery

ESG – Environment, Social and Governance

EUR – estimated ultimate recovery

FD&A – Finding, Development and Acquisition costs

GHG – greenhouse gas

IP365 – initial average production rate of 365 days

IPEP – in-pit extraction process

MMcf – million cubic feet

$MtCO_2e$ – million tonnes of carbon dioxide equivalent

NI 51-101 – National Standards of Disclosure for Oil and Gas Activities

NGL – natural gas liquids

NWR – North West Redwater Refinery

R&D – research and development

SAGD – steam assisted gravity drainage

SEC – U.S. Securities & Exchange Commission

SCO – synthetic crude oil

Advisory *(Continued)*

Reserves Notes:

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates are the 3-Consultant-Average of price forecasts developed by Sproule International Limited, GLJ Ltd. and McDaniel & Associates Consultants Ltd., dated December 31, 2024:

		2025	2026	2027	2028	2029
Crude Oil and NGLs						
WTI	US$/bbl	71.58	74.48	75.81	77.66	79.22
WCS	C$/bbl	82.69	84.27	83.81	85.70	87.45
Canadian Light Sweet	C$/bbl	94.79	97.04	97.37	99.80	101.79
Cromer LSB	C$/bbl	93.30	96.05	95.92	98.55	100.51
Edmonton C5+	C$/bbl	100.14	100.72	100.24	102.73	104.79
Brent	US$/bbl	75.58	78.51	79.89	81.82	83.46
Natural gas						
AECO	C$/MMBtu	2.36	3.33	3.48	3.69	3.76
BC Westcoast Station 2	C$/MMBtu	2.15	3.14	3.29	3.50	3.57
Henry Hub	US$/MMBtu	3.31	3.73	3.85	3.93	4.01

All prices increase at a rate of 2% per year after 2029.
A US$/C$ foreign exchange rate of 0.7117 was used for 2025, 0.7283 for 2026, and 0.7433 for 2027 and thereafter in the year end 2024 evaluation.

4. A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.
5. Oil and natural gas metrics included herein are commonly used in the crude oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
8. Reserves Life Index ("RLI") is based on the amount for the relevant reserves category divided by the 2025 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.
9. Finding, Development and Acquisition ("FD&A") costs excluding changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2024 by the sum of total additions and revisions for the relevant reserves category.
10. FD&A costs including changes in FDC are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2024 and net changes in FDC from December 31, 2023 to December 31, 2024 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation costs.
11. Abandonment, decommissioning and reclamation ("ADR") costs included in the calculation of the Future Net Revenue ("FNR") consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as at December 31, 2024 and forecast estimates of ADR costs attributable to future development activity.