

Corporate Presentation
July 2025

Tourmaline Overview

- Largest natural gas producer in Canada
- 4th largest Canadian gas processing midstream operator
- 5.5 Billion Boe 2P Reserves; 24.8 Tcf Gas, 1,356 MMbbls liquids
- Lowest capital cost operator in the basin
- Lowest net emissions and intensity of Canadian senior producers
 - 41% emission intensity reduction since '13; rated "A" by MSCI
- Peer-leading cash flow growth & free cash flow generation
- Investment Grade BBB (High) rated by DBRS
- Largest insider ownership amongst Sr E&P Peers

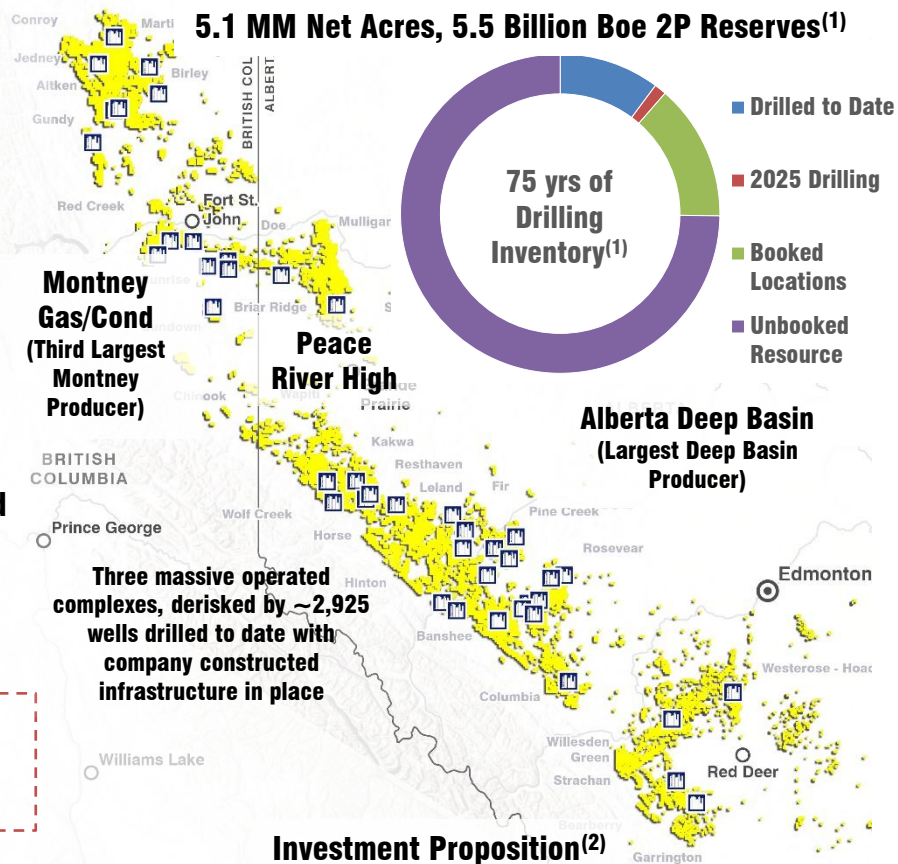
Tourmaline's scale in Canada's premium gas plays, production base and low cost infrastructure, provide investors a suite of advantages with efficiency, profitability, growth, and return on (and of) capital unparalleled by peers

Current Production Forecasts (boepd)

- 3Q25E: 625,000 – 635,000
- 2025E: 635,000 – 650,000 (640,000 EP Plan)
- 2026E: 690,000 – 710,000 (690,000 EP Plan)

Financial Position⁽²⁾

Market Capitalization (June 30 th)	\$25.6B
Net Debt (2Q25) ⁽³⁾ / net of TPZ Equity Stake (June 30 th) ⁽²⁾	\$1.9B / \$1.0B
Enterprise Value	\$26.6B
2025E Cash Flow ⁽³⁾	\$3.7B
2025E Free Cash Flow ⁽³⁾⁽⁴⁾	\$0.8B



Investment Proposition⁽²⁾

Total Return CAGR (1/3/5/10yr)	11% / 8% / 51% / 10%
FCF Yield + Organic Prod Growth (2025/2026)	8% / 10%
Dividend Yield (Base / TTM Base + Specials)	3% / 5%
EP Growth Plan Production Growth CAGR ('25-'31)	5%
YE 2024 2P PV10% ATax Reserve Value Per Share	\$88/Sh

(1) See schedule A in corporate presentation appendix; inventory life at 325 wells per year pace of development (hz locations only), reserves and acreage and wells drilled as of December 31st 2024.

(2) Free Cash Flow and dependent ratios and yields are based on current EP Growth Plan; all market data as per June 30th, 2025; EV presented net of TPZ equity value.

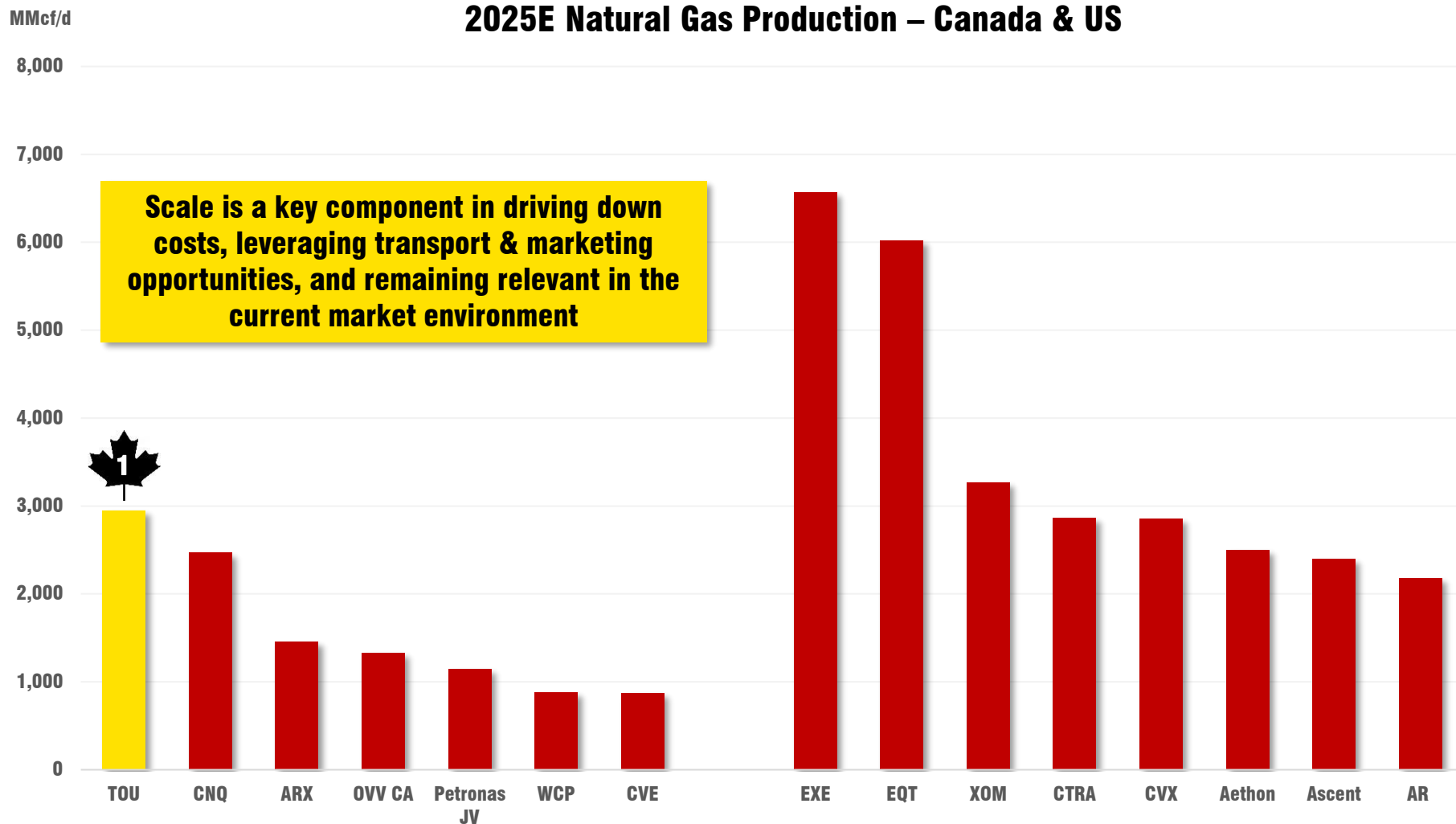
(3) See "Non-GAAP and Other Financial Measures" in Forward Looking Statement Advisories of this presentation. (4) Free Cash Flow is defined as Cash Flow less Capital Expenditures⁽³⁾, excluding acquisitions and dispositions.

Largest North American Natural Gas Producers

July 2025

Tourmaline is the largest natural gas producer in Canada, and the fourth largest gas focused producer in North America

2025E Natural Gas Production – Canada & US



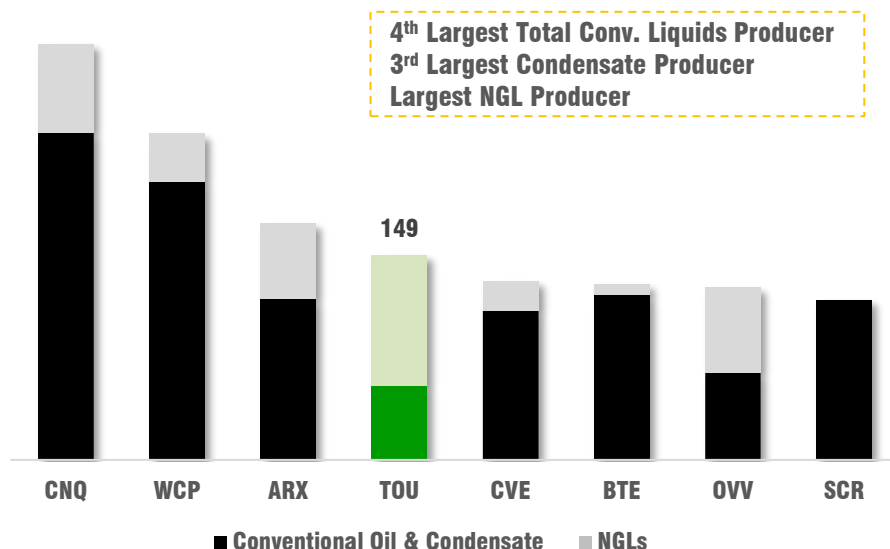
Tourmaline: A Significant Canadian Liquids Producer

July 2025

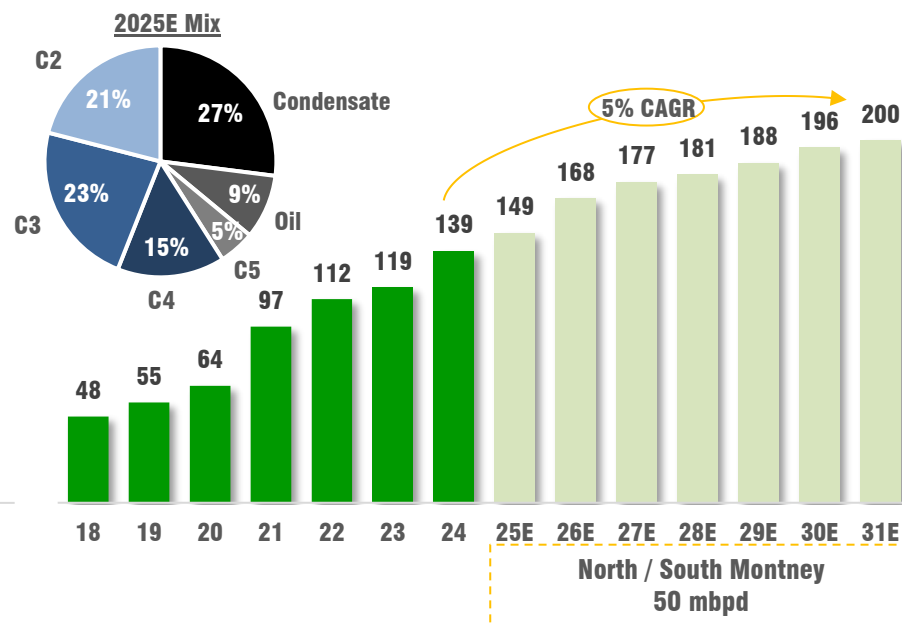
Tourmaline is a significant liquids producer in Canada, with continued peer leading growth

- **Tourmaline is the 4th largest producer of conventional liquids , 3rd largest condensate producer, and the largest producer of NGLs (>50% larger than next closest peer)**
- **Tourmaline is planning strong liquids growth with the first phase of the North and South Montney development in the EP Growth plan, adding 50 Mbpd of predominantly condensate and pentanes rich liquids production**

**Conventional Liquids (Mbpd)
Canadian Peer Producers**

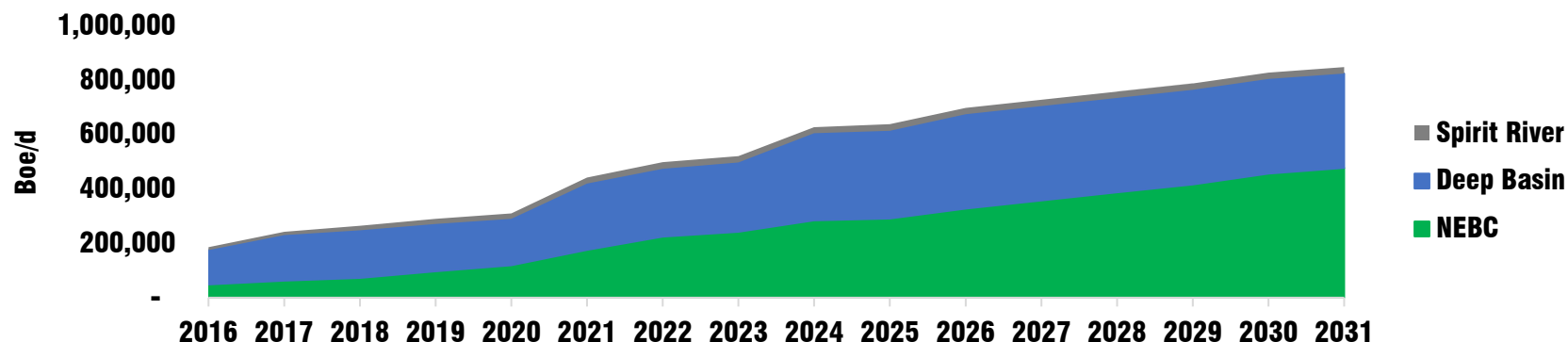


Tourmaline Liquids Growth (Mbpd)



EP Growth Plan⁽¹⁾

July 2025



	Prod'n BOEPD	After-tax Cash Flow \$MM ⁽²⁾⁽³⁾	After-tax CFPS – Diluted	E&P Capital Program ⁽⁴⁾ \$MM	Free Cash Flow ⁽⁵⁾ \$MM	Base Dividend \$MM	Declared Special Dividend \$MM	Ending Surplus (Net Debt) ⁽³⁾ \$MM
2025E (Strip)	640,000	\$3,730	\$9.71	\$2,725	\$755	(\$765)	(\$400)	(\$2,100)
2026E (Strip)	690,000	\$4,000	\$10.26	\$2,900	\$945	(\$775)	-	(\$1,930)
2027E (Flat)	730,000	\$4,880	\$12.51	\$2,900	\$1,825	(\$775)	-	(\$875)
2028E (Flat)	760,000	\$5,035	\$12.91	\$2,850	\$2,025	(\$775)	-	\$375
2029E (Flat)	790,000	\$5,250	\$13.46	\$2,700	\$2,385	(\$775)	-	\$1,985
2030E (Flat)	830,000	\$5,545	\$14.22	\$2,775	\$2,605	(\$775)	-	\$3,820
2031E (Flat)	850,000	\$5,735	\$14.71	\$2,630	\$2,940	(\$775)	-	\$5,985

(1) EP Growth Plan derived by utilizing, among other assumptions, historical Tourmaline production performance and current cost assumptions, adjusted annually after 2025. 2026 and beyond provided for illustration only. Budgets and forecast beyond 2025 have not been finalized and are subject to a variety of factors including prior year's results. See Forward Looking Information.

(2) Price assumptions: June 30th, 2025 Strip Pricing for 2025 and 2026 and a flat price deck for 2027 onwards: Gas price - \$3.64/mmbtu 2025 NYMEX US, \$4.26/mmbtu 2026 NYMEX US, \$4.00/mmbtu 2027 to 2031 NYMEX US, \$1.95/mcf 2025 AECO, \$3.15/mcf 2026 AECO, \$4.08/mcf 2027 to 2031 AECO, \$3.73/mcf 2025 PG&E Citygate US, \$4.92/mcf 2026 PG&E Citygate US, \$5.50/mcf 2027 to 2031 PG&E Citygate US, \$12.65/mcf 2025 JKM US, \$12.10/mcf 2026 JKM US, \$12.00/mcf 2027 to 2031 JKM US. Oil price - \$65.00/bbl 2025 WTI US, \$61.35/bbl 2026 WTI US, \$65.00/bbl 2027 to 2031 WTI US. Foreign Exchange – 0.72 2025 USD/CAD, 0.74 2026 – 2031.

(3) See “Non-GAAP and Other Financial Measures” in Forward Looking Statement Advisories.

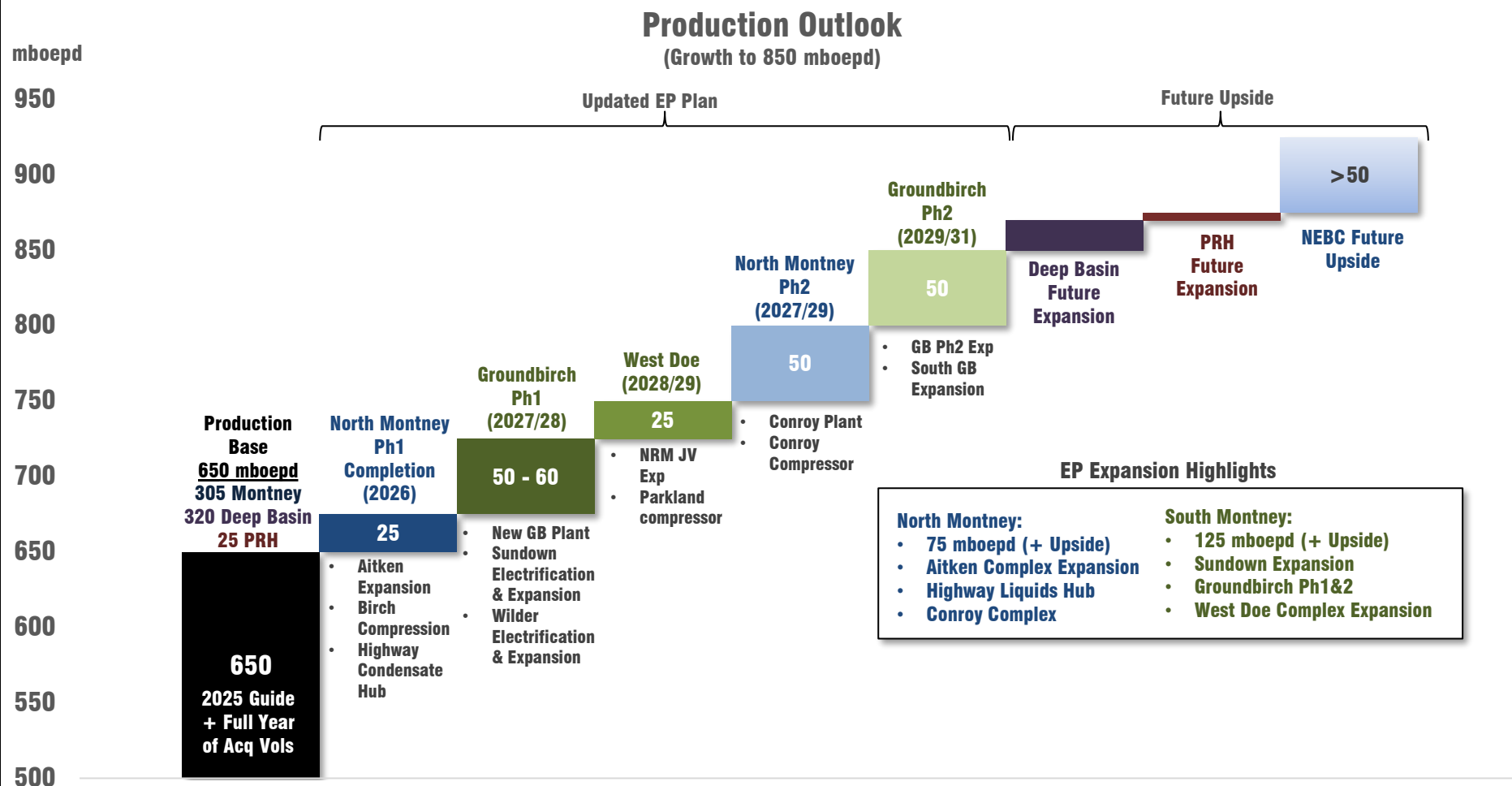
(4) E&P Capital Program is defined as Capital Expenditures⁽³⁾, excluding acquisitions, dispositions, exploration capital and other corporate expenditures.

(5) Free Cash Flow is defined as Cash Flow less Capital Expenditures⁽³⁾, excluding acquisitions and dispositions. Free Cash Flow is prior to dividend payments made by Tourmaline.

Tourmaline EP Project Summary

July 2025

Tourmaline's NEBC build out will include 2 new facilities and 4 complex expansions, 3 new liquids hubs, providing 200 mboepd of high margin volume growth into the next decade



2024-2031 NEBC Infrastructure Project Overview

July 2025

- This is the largest EP growth project in the WCSB over the next 5 years and is timed to the growing Canadian LNG business.
- Tourmaline expects to add 1.1 bcf/d of new gas production and over 50,000 bpd of condensate and ngl's over the next six years
- The two-phase project will systematically develop Tourmaline's most profitable resource inventory (lowest capital cost, lowest operating cost, most liquid rich, highest margin), resulting in Tourmaline's operating metrics improving as production from this new development project becomes a larger proportion of the corporate production base.
- The build out consists of two new gas processing complexes with C3+ deep cut recoveries, expansion of four existing gas processing complexes, three new hydrocarbon liquids hubs including evaluation of an LPG terminal at Groundbirch, five water recycling facilities, electrification of four processing plants of which two are existing, and several large pipeline corridors connecting our large resource base to the existing and new gas processing complexes.
- The infrastructure build-out commenced in 2024 with one of the liquid storage projects, one of the connector pipeline projects, a water facility, the compression expansion at Birch, and one of the electrification projects all expected to be completed by end 2025 on approximately \$350 million of aggregate capital spending.
- The first material production addition occurs in Q4 2026 with the Aitken C-38-C plant expansion, the next significant production addition is phase one of the Groundbirch 15-25 deep cut planned for 2H 2027. Both projects are permitted and long-lead procurement is underway.
- Tourmaline expects production growth of 30%, cash flow growth of over 40% and free cash flow growth of 2.5 times at flat pricing once the project is completed and the EP program trends towards maintenance capital levels (\$>3.0 billion FCF per Annum).

'We're not just growing the business; we're improving the business.'

NEBC Montney Gas/Condensate Complex

July 2025

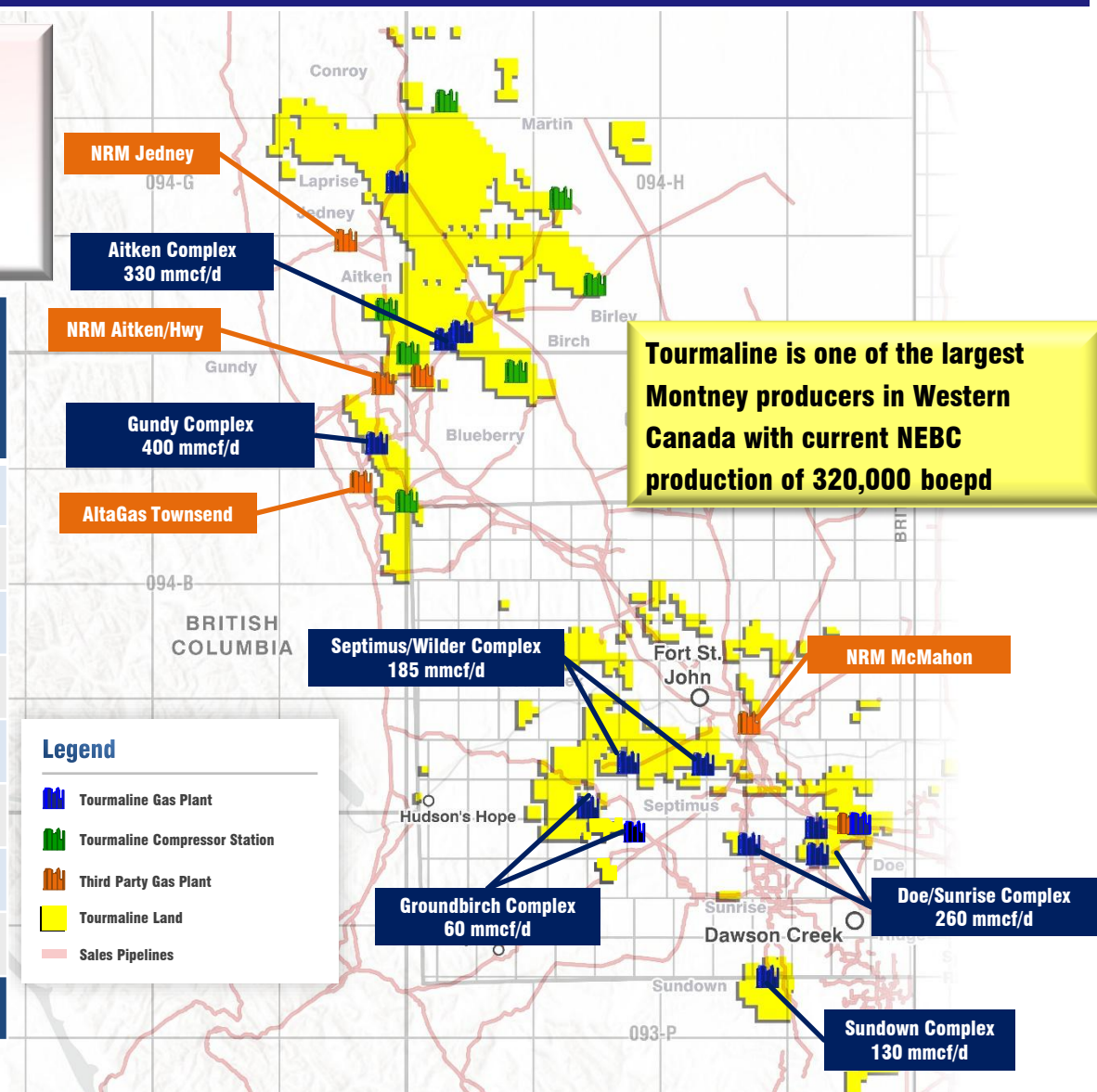
Current Prod. 320,000 boepd

Current Reserves 3,279 mmboe (Dec 31, 2024)

Montney Drilling Inventory In excess of 7,857 horizontal locations. (Dec 31, 2024)

Processing Complex Name	Current Capacity (mmcf/d)	Planned Capacity (mmcf/d)
Aitken	330	450
Gundy	400	400
Septimus/Wilder	185	220
Groundbirch	60	Up to 500
Doe/Sunrise*	260	410
Sundown	130	250
Conroy	0	Up to 250
3 rd Party	350	~350
Total	1.7 Bcfpd	~2.8 Bcfpd

*Includes West Doe



Alberta Deep Basin

Mar 2025

The contiguous Tourmaline interconnected Deep Basin Cretaceous gas asset is effectively Alberta's Largest Gas Field

- **Current Production** 320,000 boepd
- **Current Reserves** 1,945 mmboe (as at Dec 31, 2024)
- **Tourmaline Land Base** 3.2 million acres
- **Drilling Inventory** 14,794 hz locations

The Company has drilled 1,345 wells to date with a future drilling inventory of 14,794 hz locations

Doe Creek *

Cardium *

Dunvegan *

Viking *

Notikewin *

Falher *

Wilrich *

Bluesky/

Glauconitic

Gething *

Cadomin *

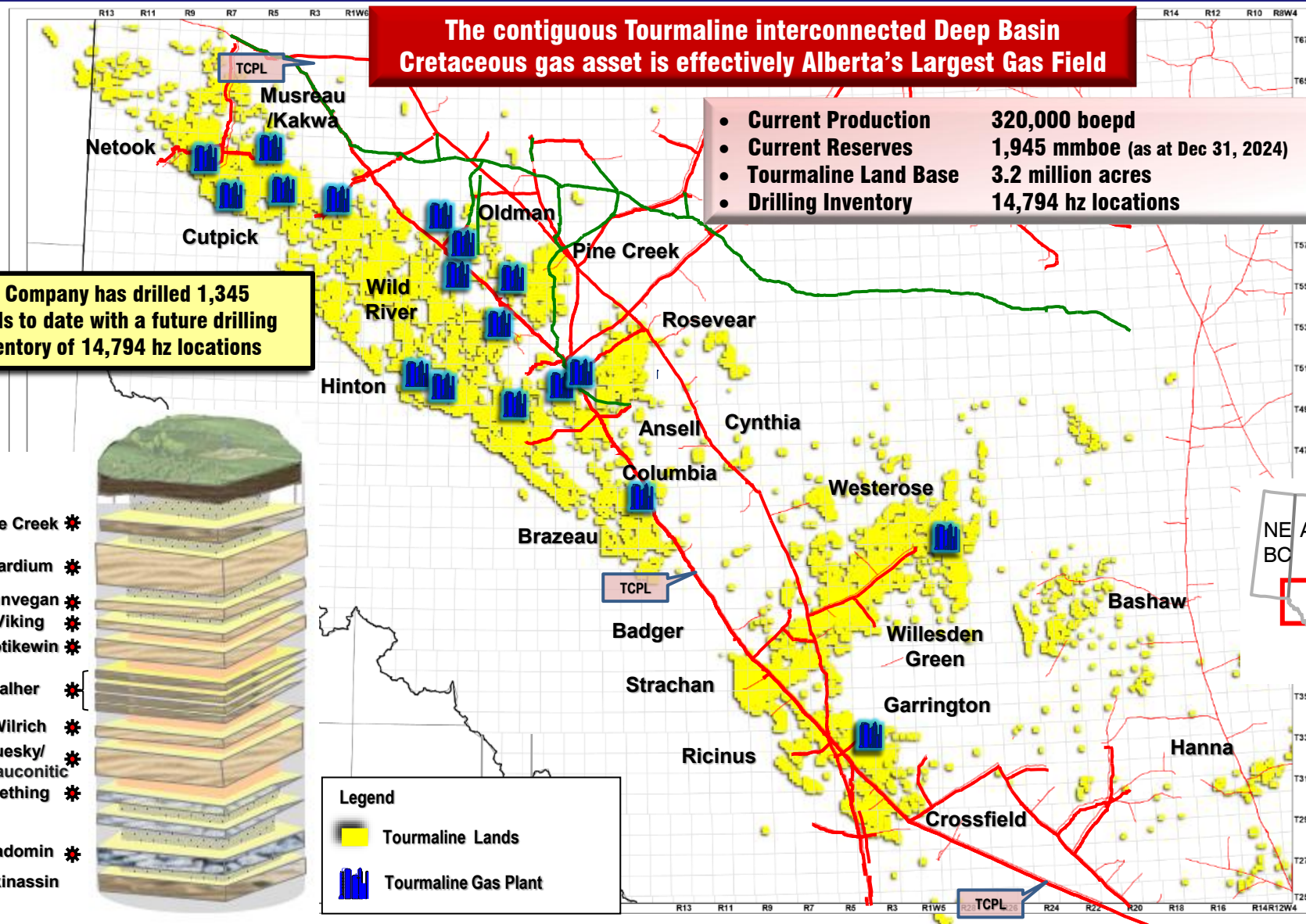
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Legend

 Tourmaline Lands

 Tourmaline Gas Plant

NE Alberta
BC

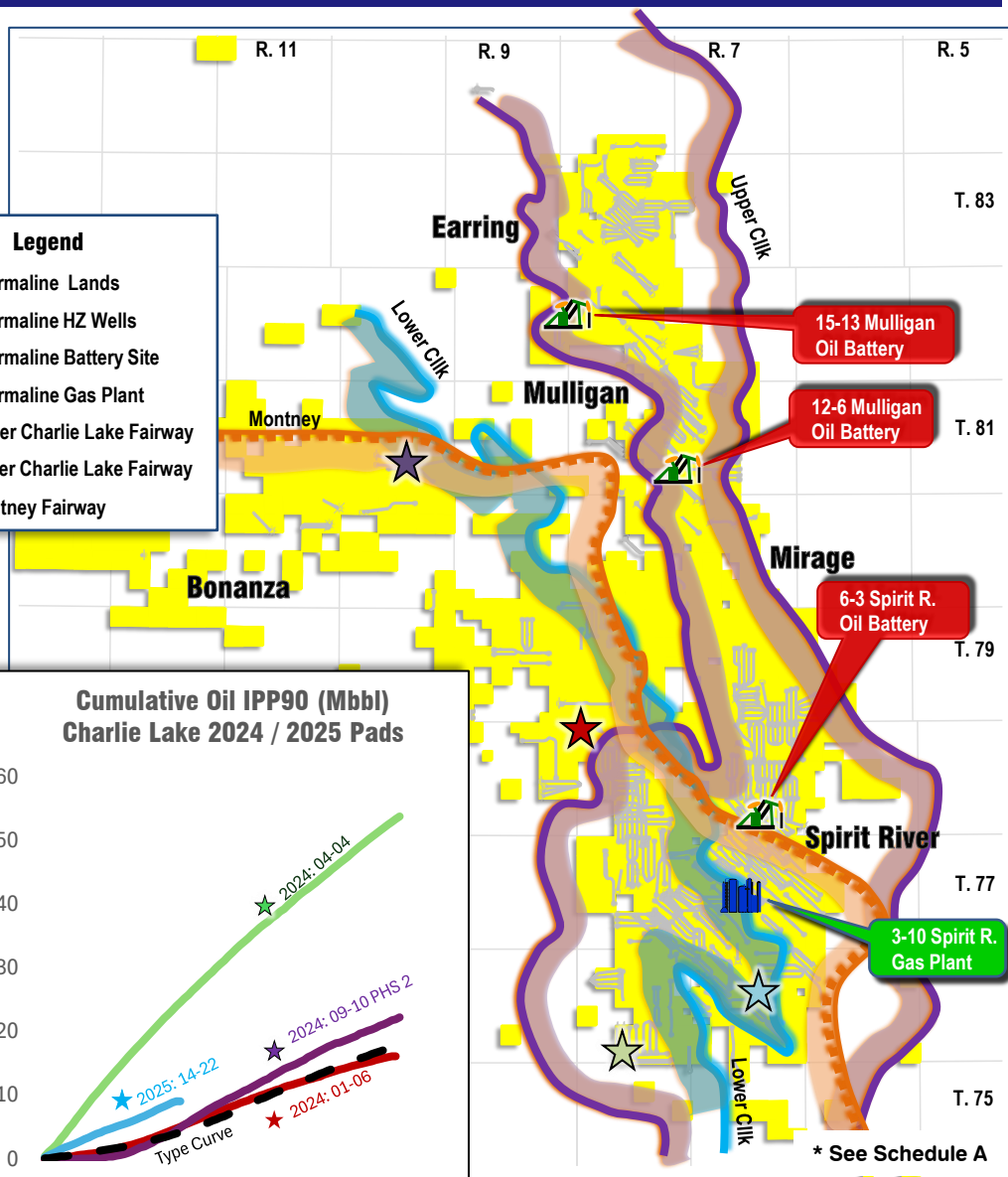
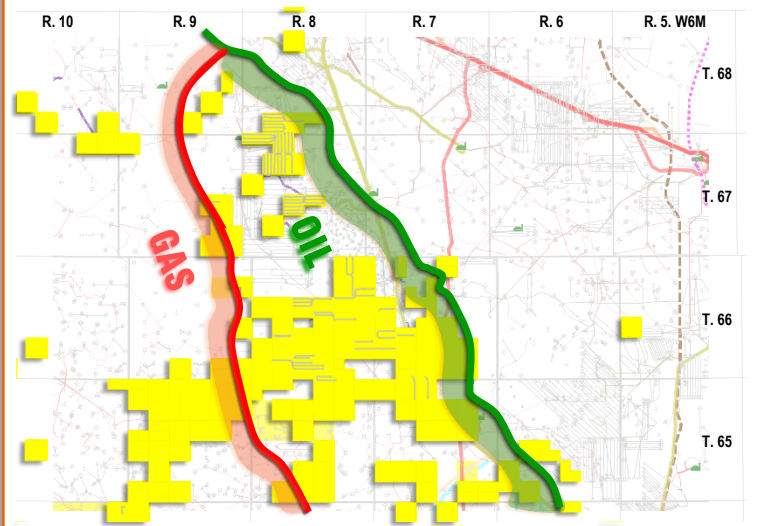


Peace River High

- 2,428 Horizontal Locations* along Regional Play Fairways
- Current Reserves of 272 mmboe (Dec 31, 2024)
- Regional pools defined by >400 horizontal wells
- 2.5 – 3.4 bcfe 2P reserves per horizontal Charlie Lk/Montney
- \$3.0 - \$4.5M Charlie Lake / Montney horizontal Drill/Complete Cost
- Upper Charlie Lake wells are profitable on a full cycle basis at \$30/bbl (U.S. WTI)

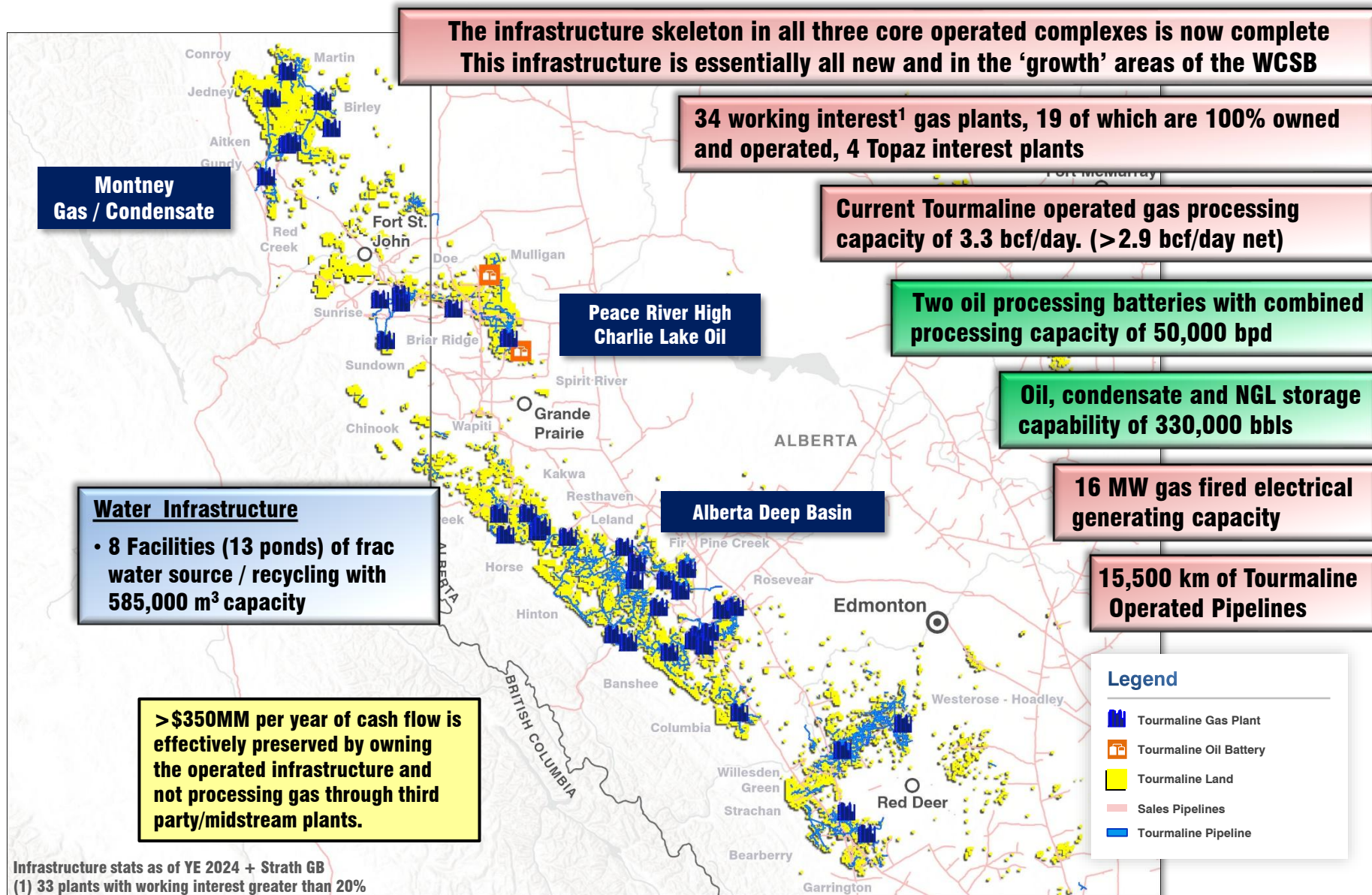
Wapiti Cardium Complex

Cardium Oil Window
Cardium Gas Window



Tourmaline Midstream Assets

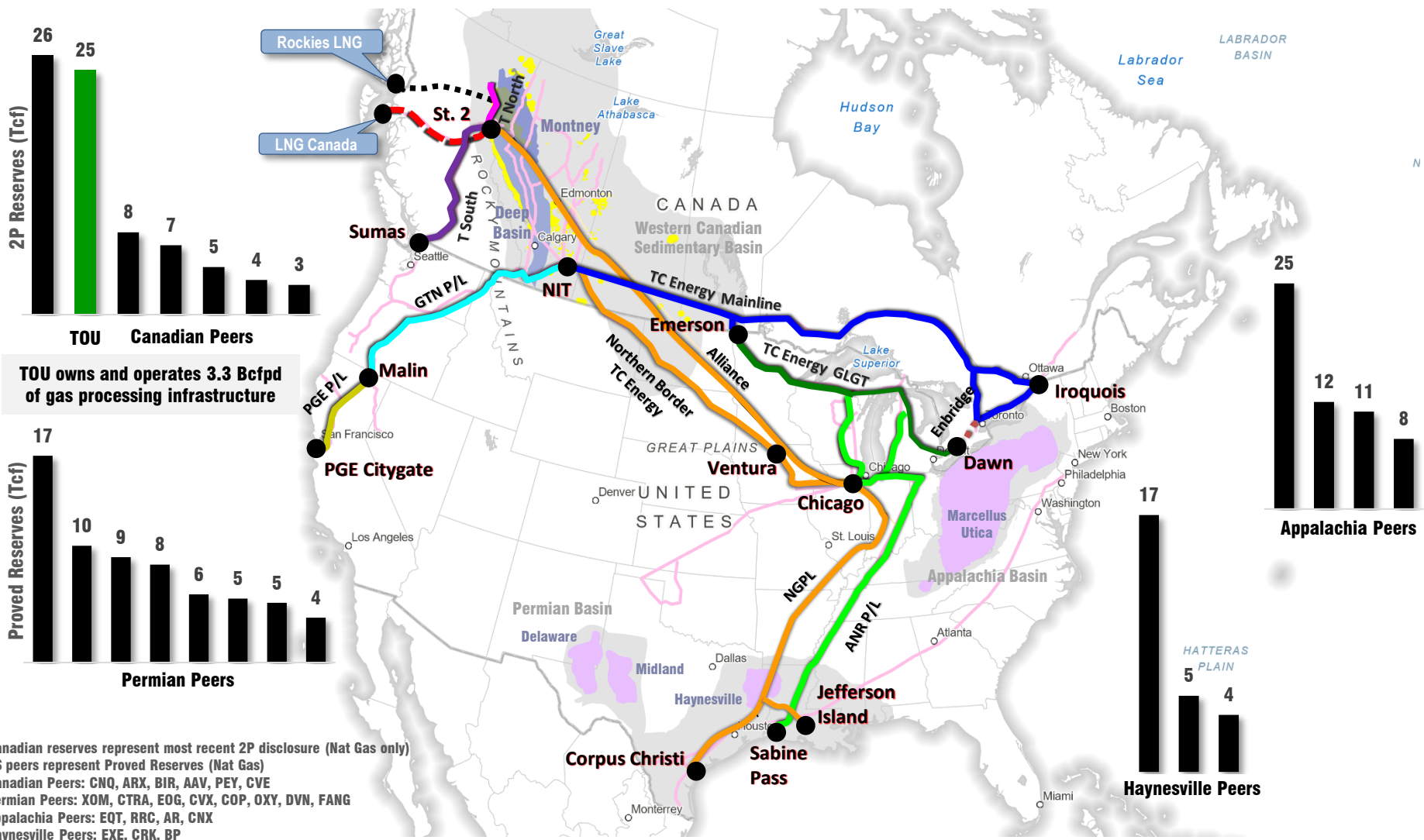
July 2025



North American Natural Gas Reserves

July 2025

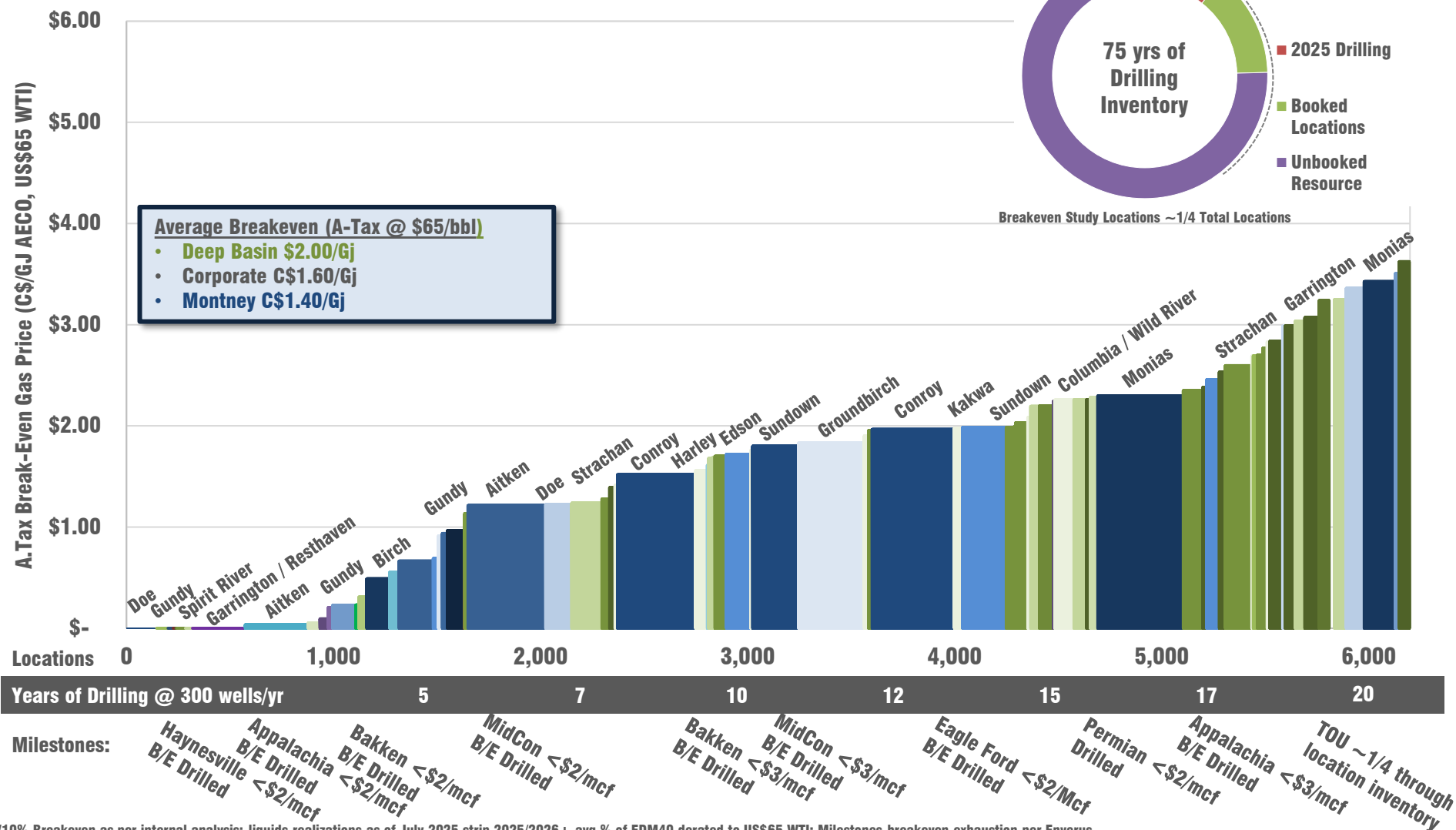
Companies that own the largest, lowest development cost, transport-integrated natural gas reserves, will increasingly dominate the Energy space in the next 20 – 30 years



Multiple Decades of Tier 1 Inventory

July 2025

Tourmaline's deep inventory ownership provides multiple decades of very profitable development, plus no need to pursue large "resource reloads" in A&D market



July 2025

Mntn 2025 New Zone Test

- Tested at 12.5 mmcfpd
- Multiple follow-ups planned

Groundbirch-Sunrise Montney SQ2

- 1-24-80-16W6 (Recent Test)
 - IP. 180 – 2.53 mmcf/d & 256 bbl/d cond/C5+
 - EUR - 3.1 bcf & 204 mmbbls cond/C5+
- 128 Incremental locations

2024 Deep Basin New Zone

- Vertical Pilot well drilled
- 3 Hz wells drilled into zone
- 3 well average EUR of 8.6 bcf
- Over 40 Potential locations

Legend

-  Tourmaline Lands
-  Tourmaline Gas Plant
-  3rd Party Gas Plants
-  Tourmaline Oil Battery
-  Tourmaline Pipelines
-  Main Sales Pipelines
-  Gas Discovery

Exploration program success has created significant incremental value in existing core complexes, the majority of the discoveries can access Tourmaline infrastructure. 22 new zones discovered, with 140 successful new zone or follow up wells drilled since inception. 2,037 bcfe booked in YE 2024 reserve report, since starting the program. 1,068 incremental locations added to inventory to date.

2024 Ferrier Glauc Gas/Cond Success

- 9-28-38-07-W5M Pad
 - 09-26-038-07W5 HZ – 7.2 bcf raw, 120 mmbbls cond/C5+
 - 16-26-038-07W5 HZ – 7.2 bcf raw, 120 mmbbls cond/C5+

Wilson Creek Belly River 2025 NPW

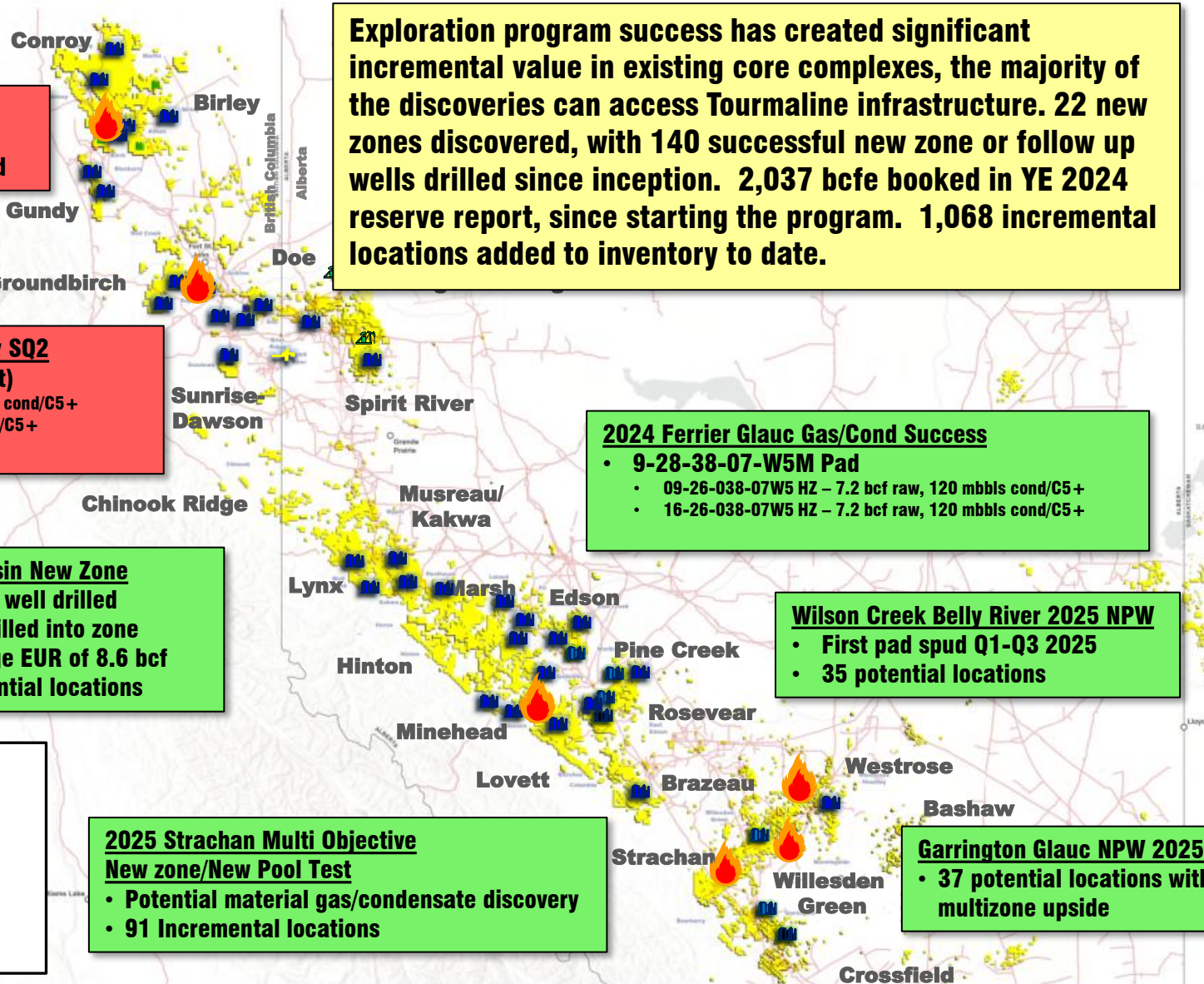
- First pad spud Q1-Q3 2025
- 35 potential locations

2025 Strachan Multi Objective New zone/New Pool Test

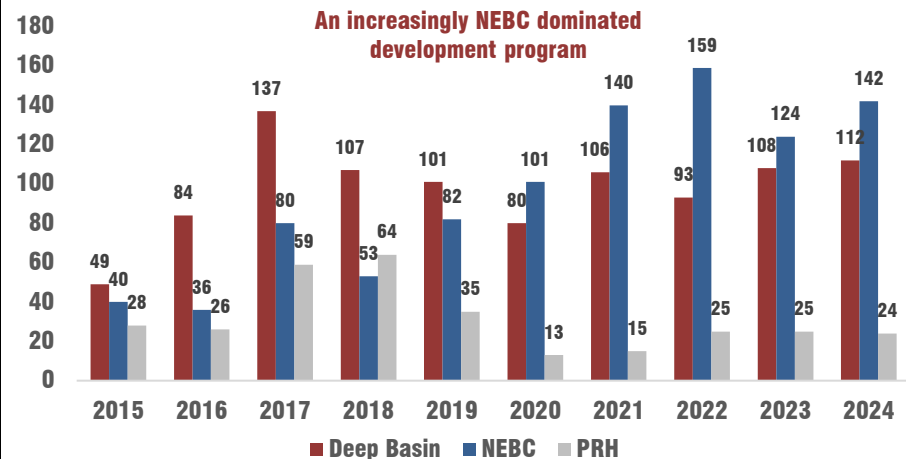
- Potential material gas/condensate discovery
- 91 Incremental locations

Garrington Glauc NPW 2025

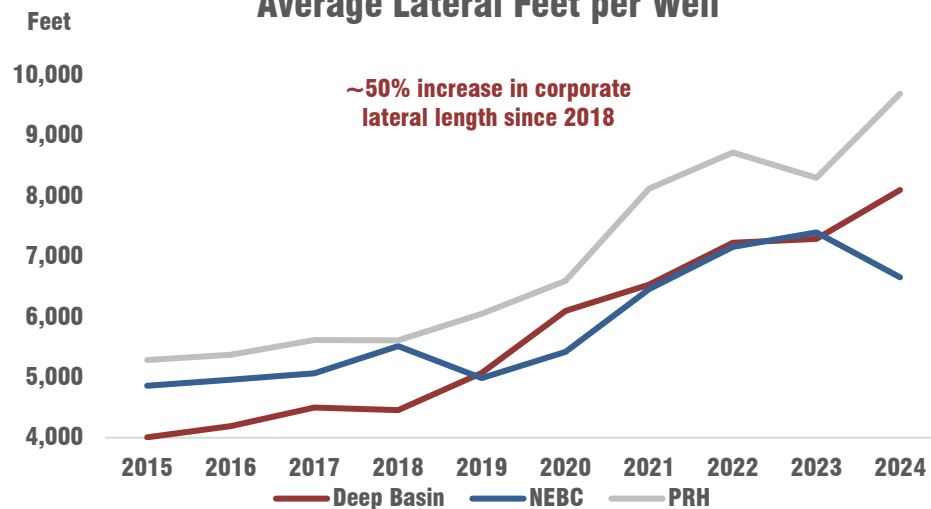
- 37 potential locations with multizone upside



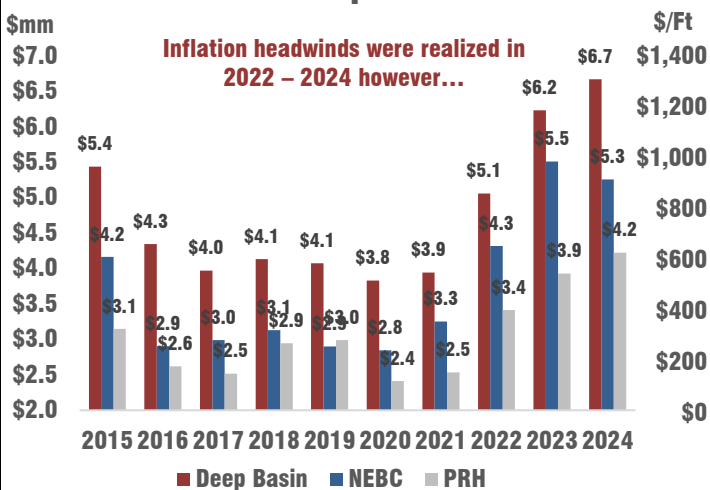
Wells Placed on Production



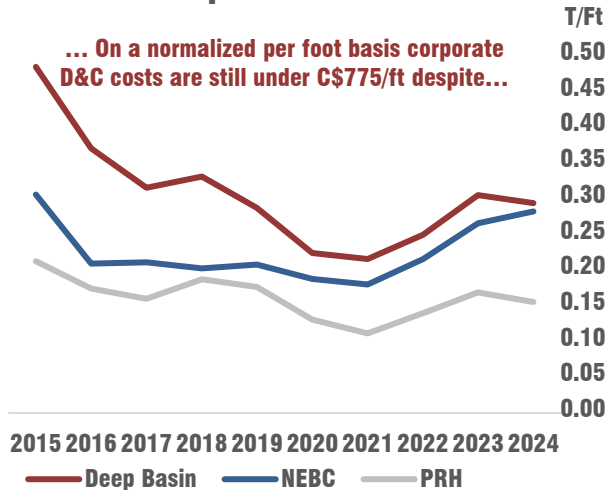
Average Lateral Feet per Well



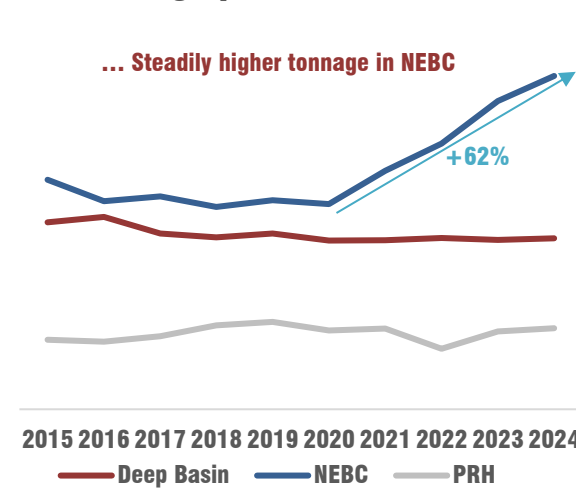
D&C Costs per Well



D&C Cost per Lateral Foot

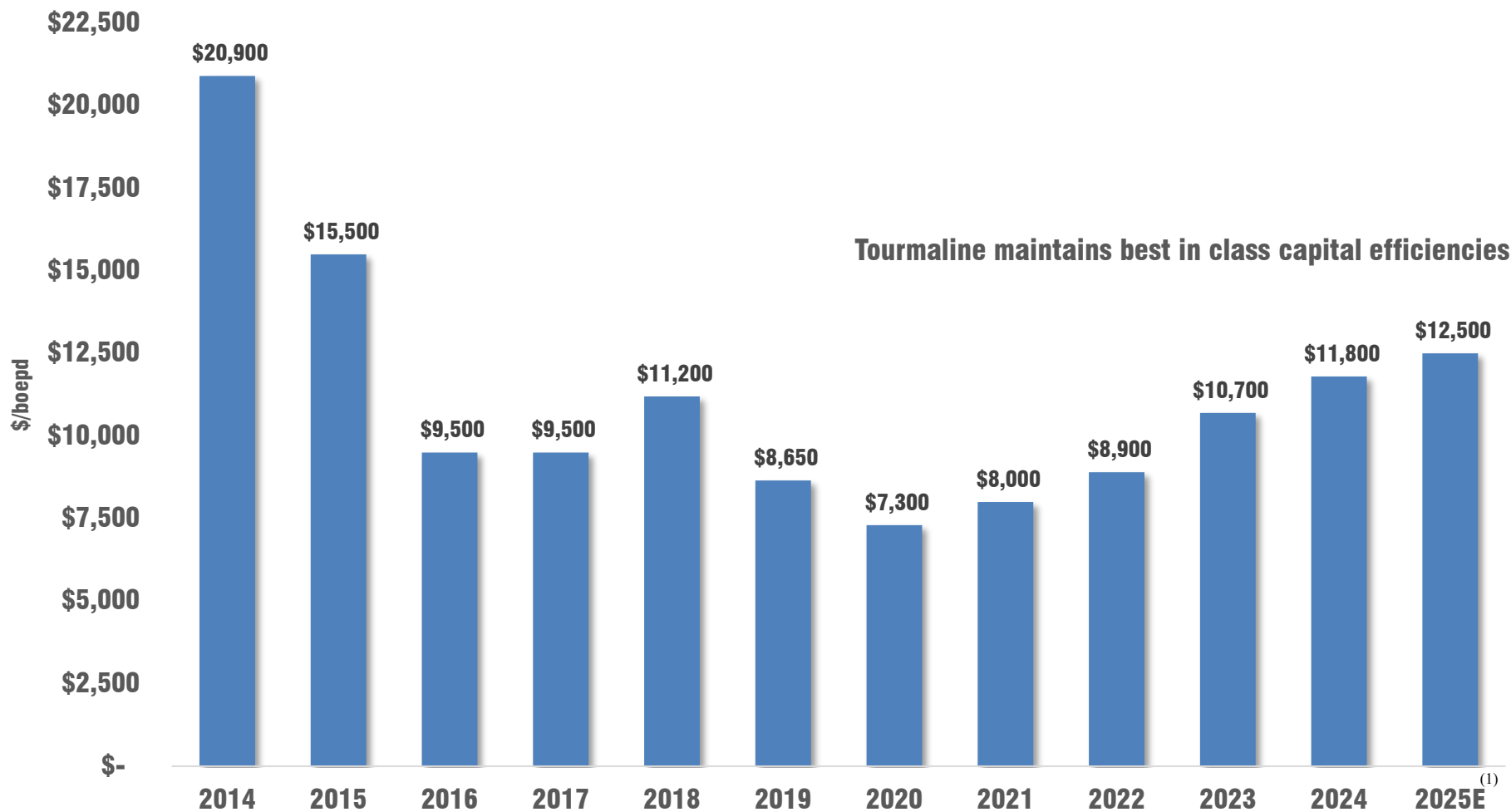


Tonnage per Lateral Foot

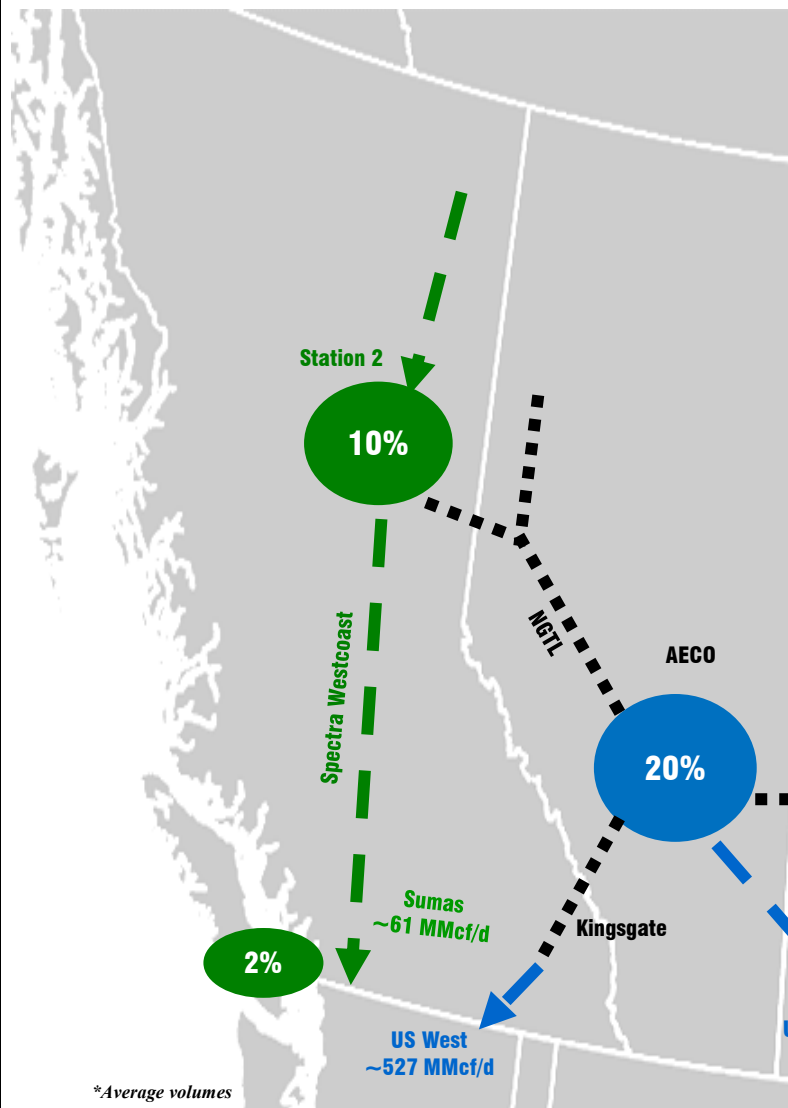


Continuous Capital Efficiency Improvements

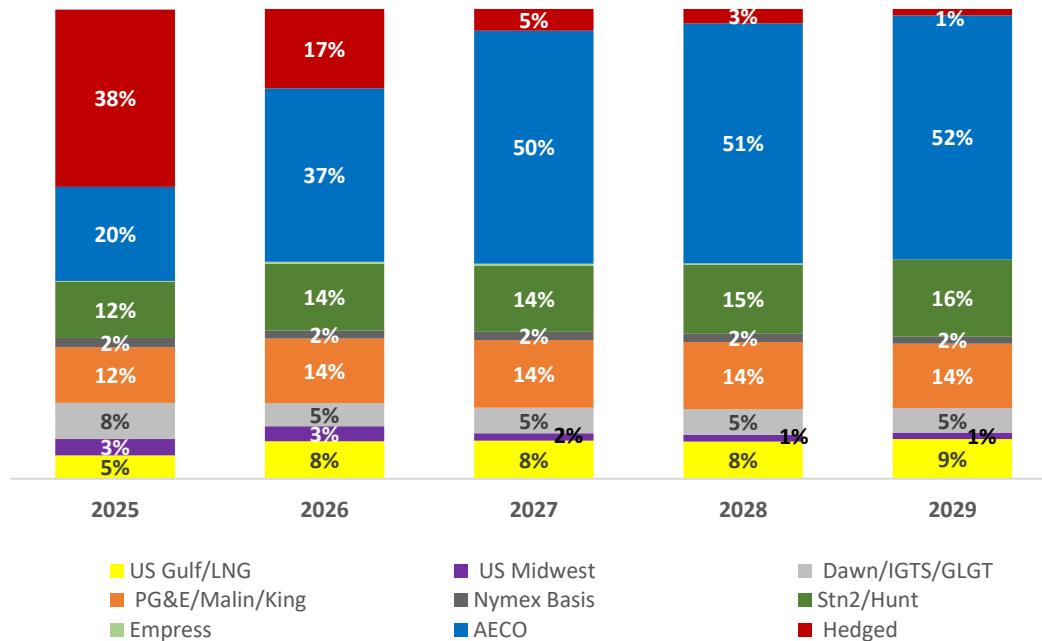
July 2025



(1) Based on EP Growth Plan Guidance



Natural Gas Price Exposure



2026 Exit: 1.2 Bcf/d of gas will flow to US/Other Markets

In 2027, 62,500 MMBtu/d of new JKM exposure commences
In 2028, 80,000 Mmbtu/d of new TTF exposure commences

Tourmaline LNG Overview

July 2025

Tourmaline continues to grow its international pricing exposure



Rockies LNG - Partner

- A partnership of Western Canadian natural gas producers working together to develop LNG export opportunities for Canadian natural gas
- Ksi Lisims site secured through project partnership with local First Nation
- LNG Sale and Purchase Agreement with Shell & Total executed to date
- Tourmaline supports Rockies LNG as a future supplier

NeeStaNan Utility Corridor (Hudson Bay LNG) - Supporter

- The NeeStaNan Utility Corridor provides access to Northern Ports and interprovincial and international trade for three prairie provinces
- Ownership consortium of Indigenous groups
- Tourmaline is an initial industry supporter of NeeStaNan and is helping to fund feasibility studies for the project

Trafigura – Medium and Long-Term LNG Agreements

- TTF Netback Agreement. Tourmaline delivers at NIT 50,000 mmbtu/d from Mar 2024-Dec 2026
- JKM Netback Agreement. Tourmaline receives JKM exposure on 62,500 mmbtu/d from Jan 2027-Dec 2033, with potential extension to Dec 2039

Uniper – Long Term LNG Agreement

- LNG Netback Supply Agreement provides international price exposure to TTF
- Tourmaline supplies 80,000 mmbtu/d to Uniper in the Gulf coast for an 8-year term starting Nov 2028

Cheniere – Delivering on Agreement Since Jan 2023

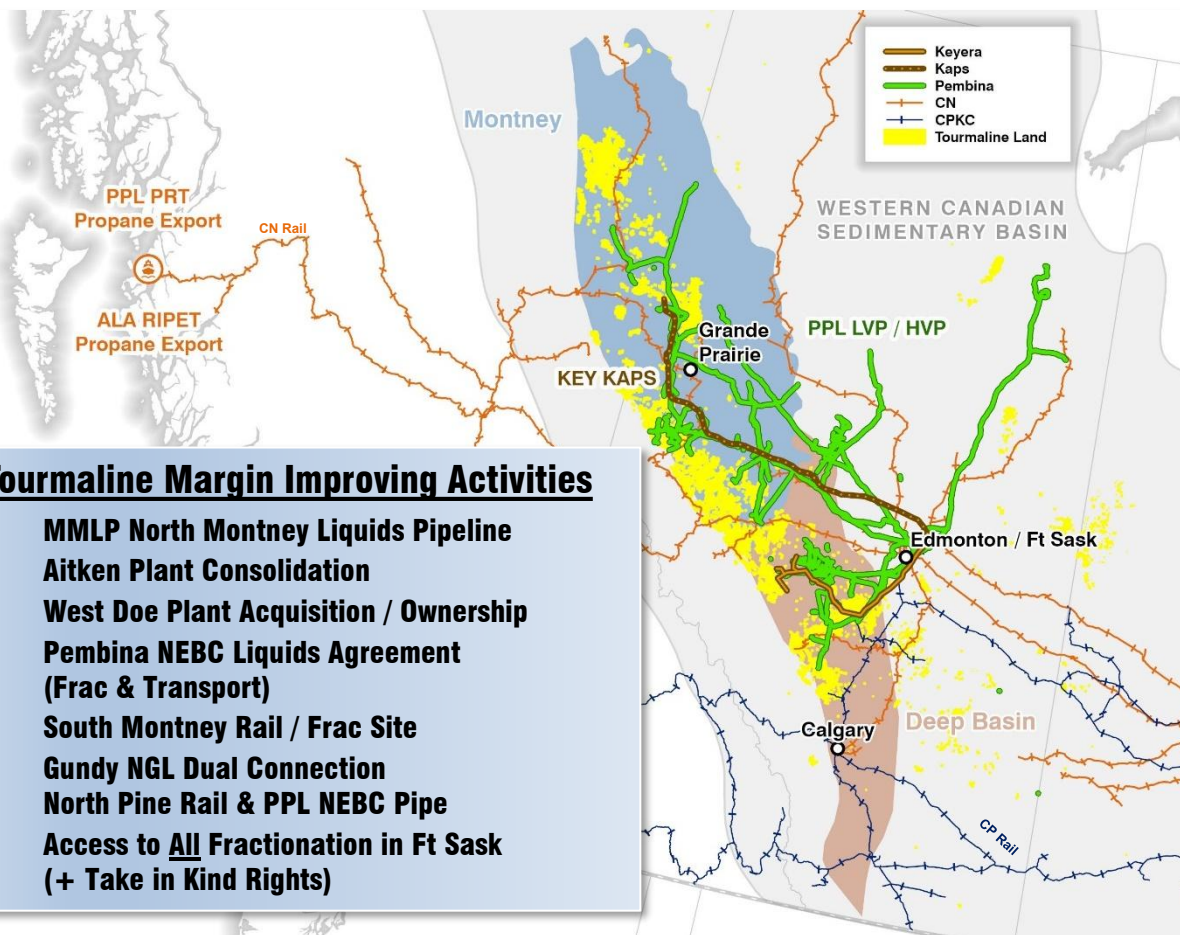
- Natural gas supplied from Tourmaline's Alberta Deep Basin and/or BC North Montney core complexes
- LNG Netback Supply Agreement provides international price exposure to JKM for Tourmaline
- Tourmaline supplies 140,000 mmbtu/d (1 cargo/month), 15 year term
- Tourmaline natural gas will now access Asian & European markets

The Growing Tourmaline Liquids Business

July 2025

Tourmaline's diverse and profitable liquids marketing business

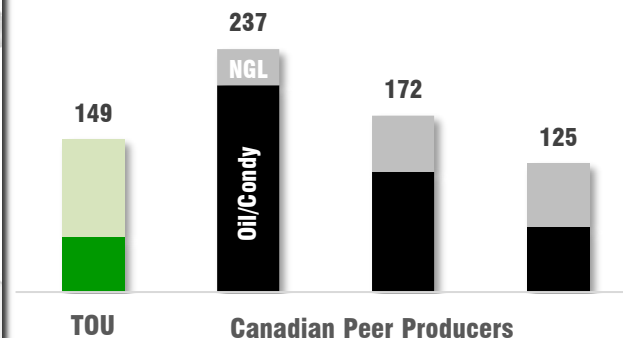
- Liquids receive diversified pricing: WTI, FSPL, Nampo/Peace, CRW, Mt. Belvieu, Conway, Far East Index, and Polypropylene netbacks
- NGL volumes are meaningfully exposed to all Canadian west coast waterborne export terminals (RIPET, PRT)
- Tourmaline ships liquids to markets on pipelines traversing our core areas – most cost-efficient method of transport



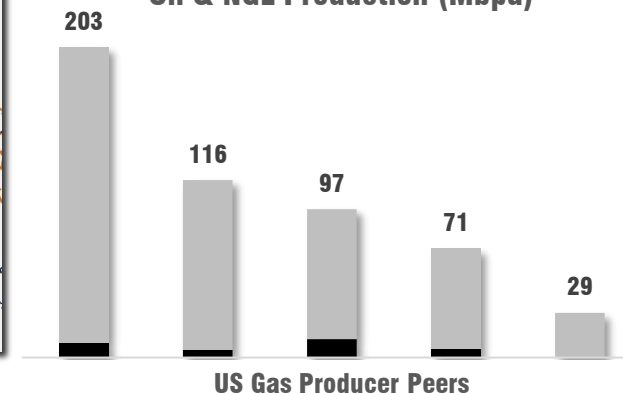
Tourmaline Margin Improving Activities

- MMLP North Montney Liquids Pipeline
- Aitken Plant Consolidation
- West Doe Plant Acquisition / Ownership
- Pembina NEBC Liquids Agreement (Frac & Transport)
- South Montney Rail / Frac Site
- Gundy NGL Dual Connection
- North Pine Rail & PPL NEBC Pipe
- Access to All Fractionation in Ft Sask (+ Take in Kind Rights)

Canadian Peer Producers Oil & NGL Production (Mbpd)



US Gas Producers Oil & NGL Production (Mbpd)

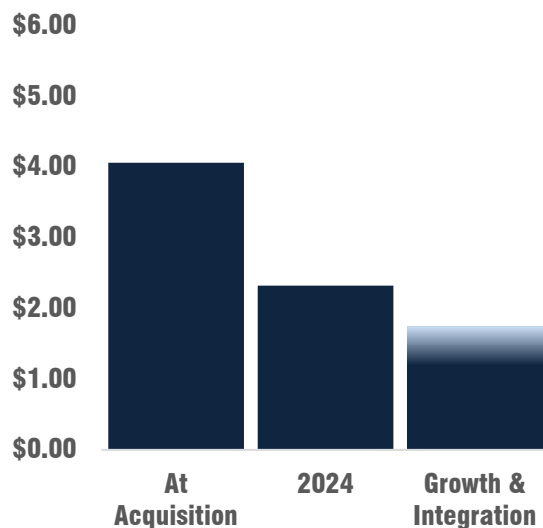


Liquids & Midstream Investment

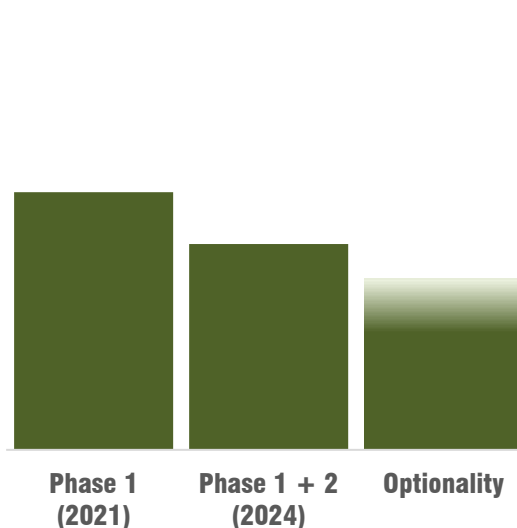
Mar 2025

Tourmaline has repeatedly driven midstream related costs down through acquisition, investment and expansion, while also driving liquids revenue higher through international marketing and integration

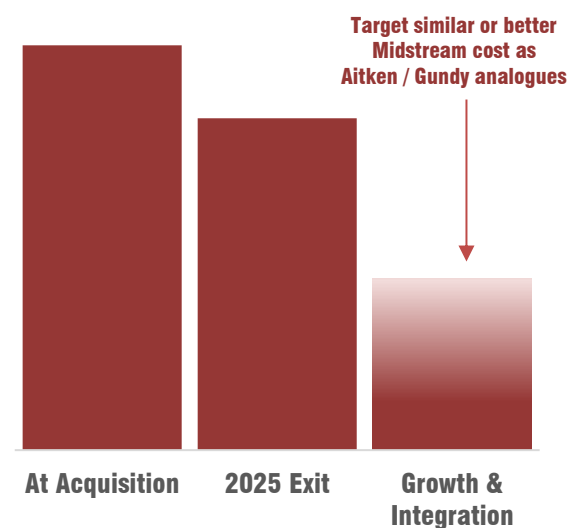
North Montney: Aitken
Midstream Cost (\$/boe)



North Montney: Gundy
Midstream Cost (\$/boe)



South Montney: Crew
Midstream Cost (\$/boe)



North Montney: Aitken Investments

- Acquire ALA ownership and expand \$295mm
- Growth and integration \$285mm (2025 – 2027)

Margin Improvement

- 100% ownership in Aitken processing
- Integration with ALA NEBC frac / rail / export
- Cost savings through growth and integration
- To date ~45% reduction in midstream cost
- Targeting additional ~25% reduction

North Montney: Gundy Investments

- Gundy Ph1 \$190mm (GP Only)
- Gundy Ph2 \$140mm (GP Expansion)

Margin Improvement

- TOU built / op (capital & runtime advantage)
- Propane integrated with ALA NEBC rail / export
- Butane optionality local / NA
- To date ~20% reduction in midstream cost
- Targeting additional ~20% reduction

South Montney: Crew Investments

- Increase ownership in existing processing
 - Fund and own 100% of new midstream
- ### Margin Improvement
- Near term grow production thru excess capacity with fixed cost structure
 - Medium term execute Groundbirch Ph1 growth and integration (analogue is Gundy Ph1)
 - Long term execute Groundbirch Ph2

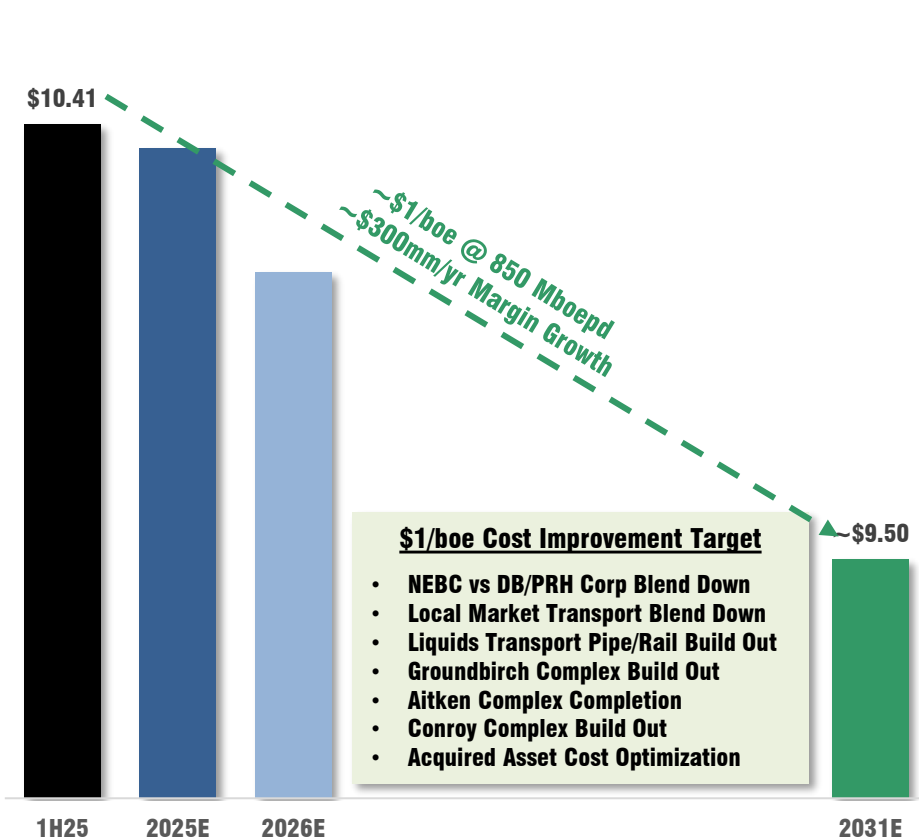
Growing Corporate Margins Through NEBC Development

July 2025

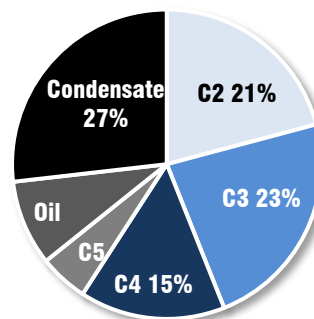
Tourmaline's NEBC growth projects improve realizations, while lowering costs driving margin growth; \$1/boe in lower operating & transport costs, with \$1/bbl liquids mix uplift drives ~\$400mm in annual additional margin

Opex & Transport Cost Structure Outlook (\$/boe)

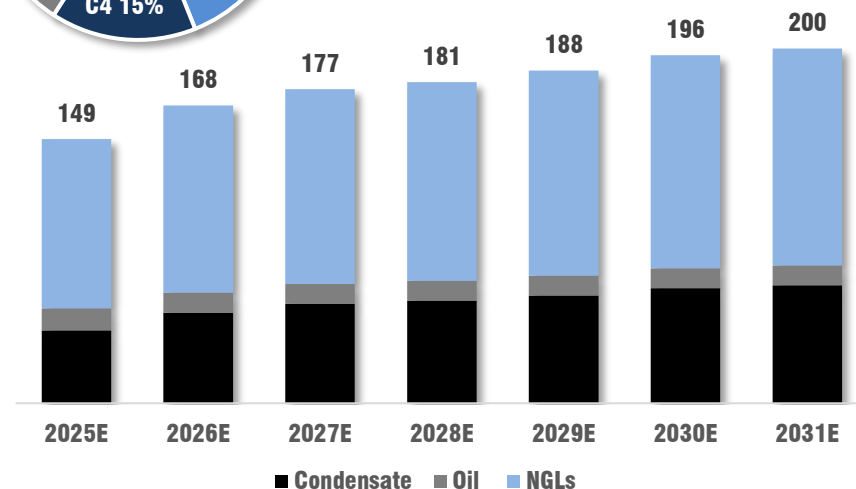
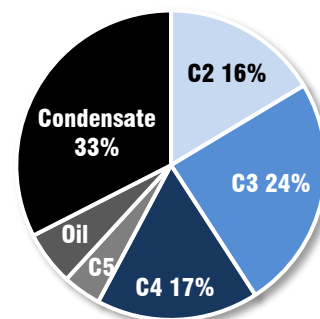
Liquids Growth and Composition Outlook (mbpd)



2025E Liquids Composition



2031E Liquids Composition



Guidance

July 2025

	<u>2025</u>⁽¹⁾
Production – Boe/d	635,000 – 650,000
Cash Flow⁽ⁱ⁾ - \$MM	\$3,730 (at 640,000 boepd)
CFPS - Diluted⁽ⁱ⁾	\$9.71 (at 640,000 boepd)
E&P Capital Program⁽ⁱⁱⁱ⁾ - \$MM	\$2,600 – \$2,850
Capital Expenditures⁽ⁱ⁾ - \$MM	\$2,850 - \$3,100
Free Cash Flow⁽ⁱⁱⁱ⁾ - \$MM	\$755 (at 640,000 boepd)

(1) Price Assumptions: June 30th, 2025 Strip Pricing: Gas price - \$3.64/mmbtu 2025 NYMEX US, \$1.95/mcf 2025 AECO, \$3.73/mmbtu 2025 PG&E Citygate US, \$12.65/mcf 2025 JKM US; Oil price - \$65.00/bbl 2025 WTI US; Foreign Exchange – 0.72 2025 USD/CAD.

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Tourmaline 2026 After Tax Cash Flow Sensitivity & Allocation

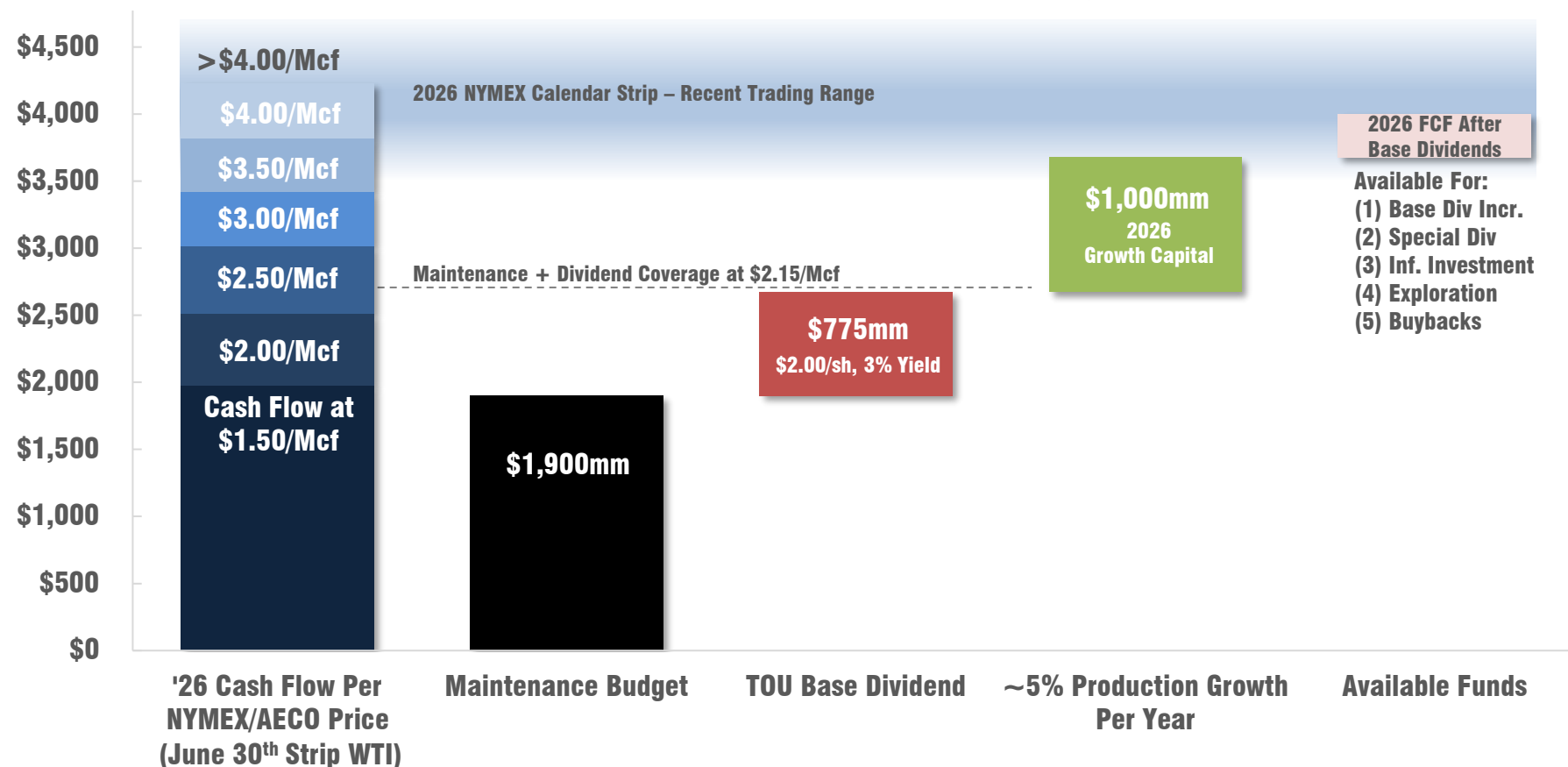
July 2025

Tourmaline's low cost structure drives sustainable return on, and of, capital opportunities

- TOU's maintenance budget, and dividend is fully funded at US\$2.15/mcf NYMEX & C\$2.15/Mcf AEEO
- TOU will manage growth capital in each annual EP program to achieve free cash flow of ~\$1bn or greater
- FCF allocated to base & special dividends, defensive buybacks, infrastructure, and exploration

(C\$mm)

2026 AT Cash Flow NYMEX/AECO Sensitivity & Allocation



Tourmaline Long Term Value Progression

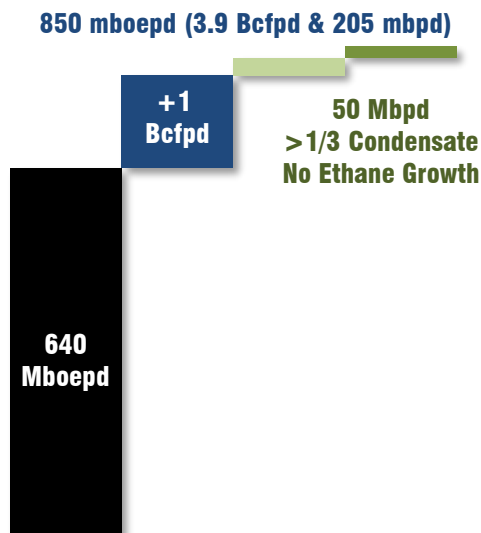
Illustrative 'Flat Deck' CF & FCF Outlook

July 2025

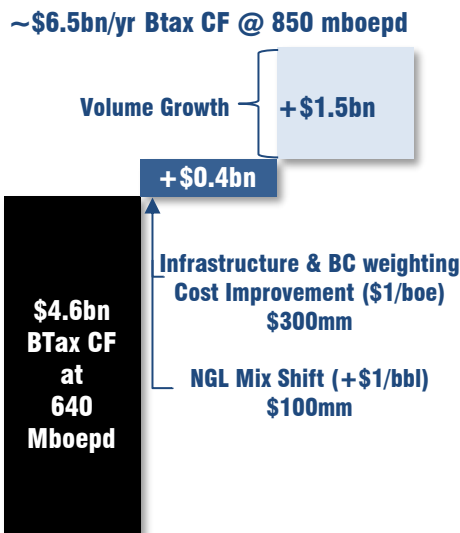
Investments in NEBC will double FCF generation through volume growth, margin expansion, and a migration to maintenance capital to enhance shareholder returns at 850 mboepd

- 30% production growth facilitates >40% cash flow growth through margin expansion and efficient BC operations
- FCF generation grows by 2.5x as widening cash flow margins combine with maintenance capital at 850 mboepd
- Buildout from 640 to 850 mboepd will sequence volume growth into strongly priced demand markets while ensuring ongoing free cash generation continues to fund shareholder returns over and above the base dividend
- Tax adjusted, future maintenance FCF implies >12% annual cash returns for shareholders at today's valuation

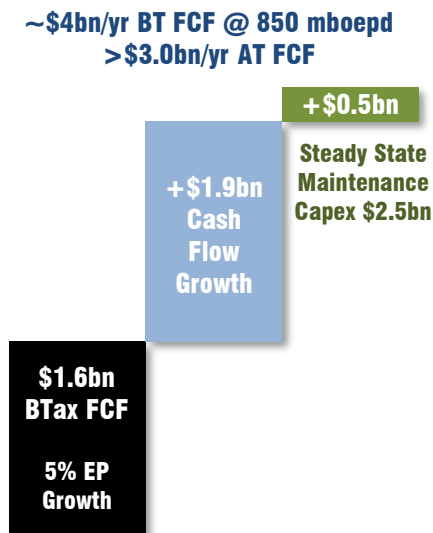
Production Outlook (Growth to 850 mboepd)



Annual BTax Cash Flow \$65 WTI / \$4 HHUB/AECO



Annual BTax Free Cash Flow \$65 WTI / \$4 HHUB/AECO



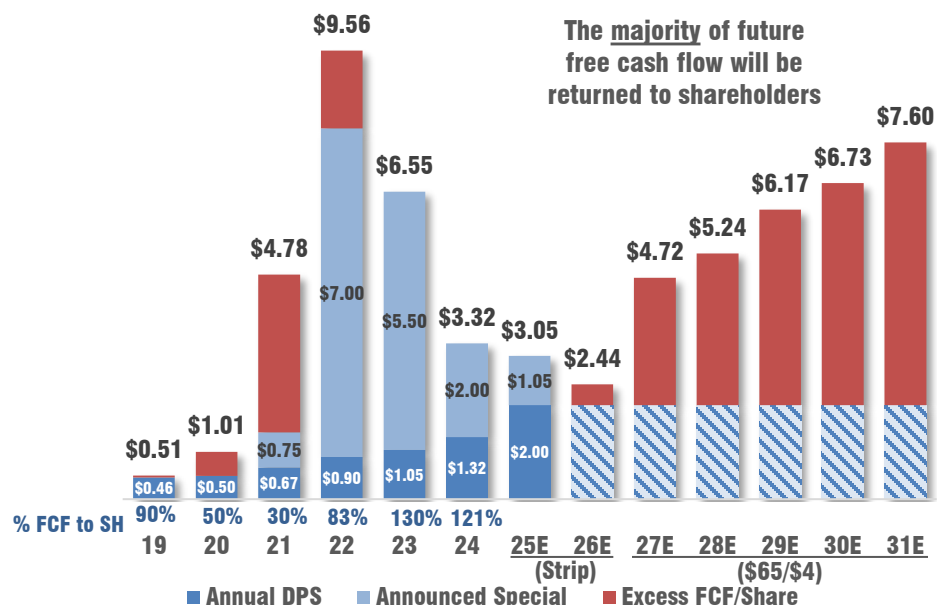
The majority of Tourmaline's free cash flow will be returned to shareholders; a growing base dividend and special dividends will be the preferred method of shareholder returns

- **Base dividend will continue to grow alongside the base EP business and will remain sustainable even in sub US\$2/mcf gas prices**
- **Special dividend offers an instrument for cash return to shareholders during accommodative commodity prices**
- **Alongside dividends, free cash flow will be allocated towards: (1) maintaining a pristine balance sheet, (2) high return infrastructure investment opportunities, (3) modest exploration, (4) defensive share buybacks**

Dividends Per Share – Base & Special

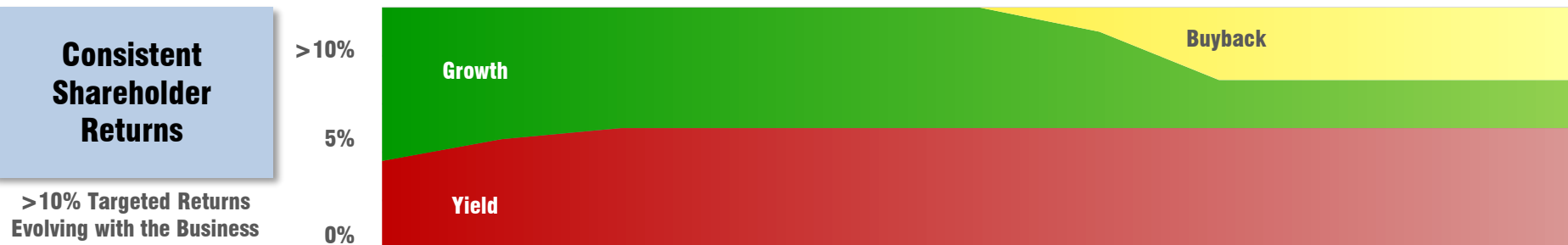
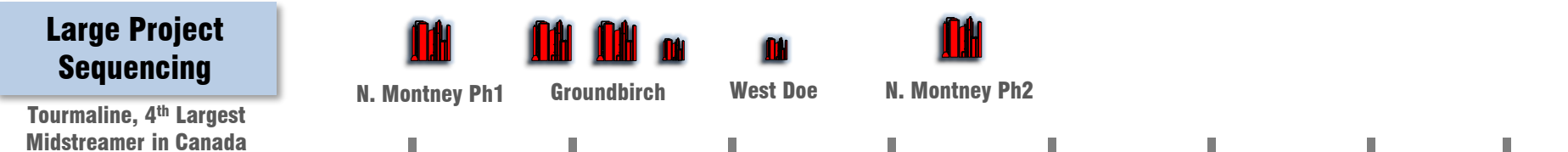
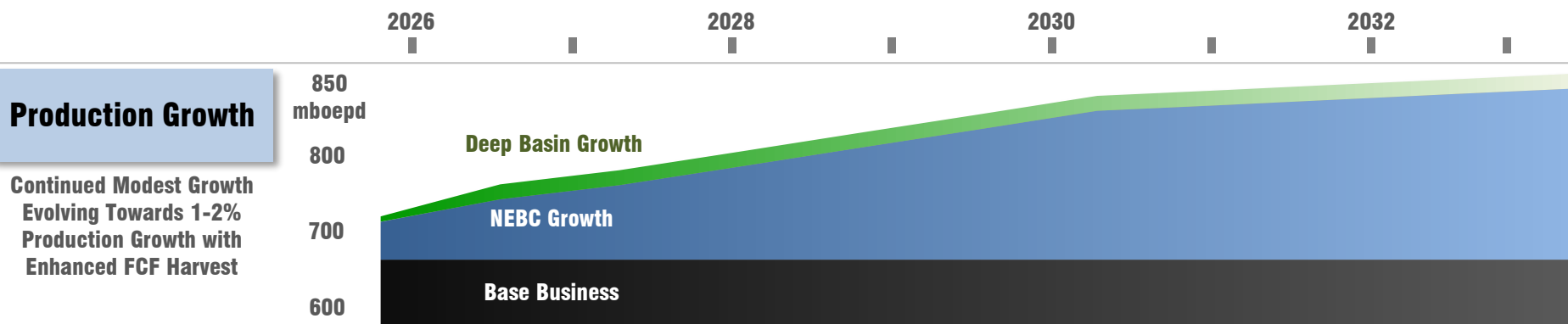


Free Cash Flow & Dividends per Share



Tourmaline Long Term Business Plan Growth & Leading Shareholder Returns

July 2025

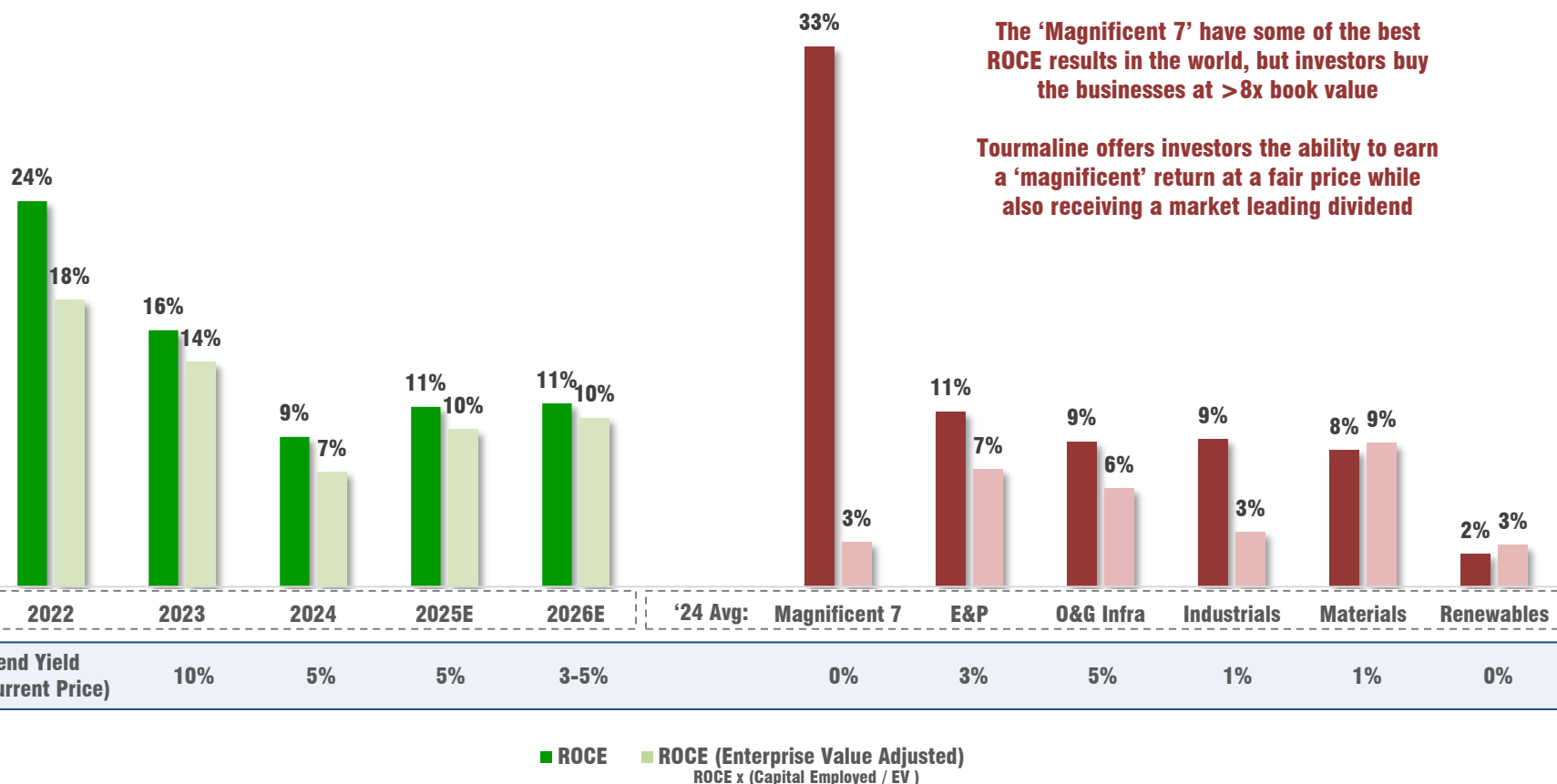


Additional Optionality and Upside Layers of Value	Incremental Capital Opportunities - Topaz Equity - Internal Value Crystallization - Asset Sales - Run Rate D/CF 0.3 – 0.4x (\$1.5bn LTD) >\$2bn	Midstream Margin Improvements - Liquids Midstream (Rail, Liquids Hubs) - Gas Midstream (BC Processing Infra Growth)	Exploration Program - Ongoing New Pool / Zone Exploration - Large Pool Tests in 2026 - 2028
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Market Leading Return on and of Capital

July 2025

Tourmaline's return on capital employed ("ROCE") will inflect to >10% with base and special dividends offering a future income yield in the mid to high single digits with upside in stronger commodity price environments



The 'Magnificent 7' have some of the best ROCE results in the world, but investors buy the businesses at >8x book value

Tourmaline offers investors the ability to earn a 'magnificent' return at a fair price while also receiving a market leading dividend

ROCE defined as Income before taxes and Finance expense divided by Capital Employed, where Capital Employed is defined as the average of Total Assets less the average of Current Liabilities for the respective year.
ROCE (Enterprise Value Adjusted) is calculated by multiplying ROCE by the Capital Employed to Enterprise Value ratio implied in the annum.
For the purposes of ROCE, Tourmaline's Income before taxes and Finance expense has been adjusted to exclude gain on acquisition (\$250mm in 2021, \$122mm in 2022, \$82mm in 2023, \$279mm in 2024), gain on loss of control of Topaz (\$321mm in 2021) and unrealized gain (loss) on financial instruments (-\$93mm 2021, \$2,101mm in 2022, -\$658mm in 2023, -\$299mm in 2024).
Magnificent 7 = META, AAPL, AMZN, NFLX, NVDA, TSLL, GOOG; Renewables = ENPH, ALB, ON, QS, VWS, FSLR; O&G Infra = TRP, PPL, PAA, KMI, LNG, ENB; Industrials = CNR, CP, UNP, WCN, CAT, BA, GE, TRA;
Materials = FM, NTR, TECK/B, X, AA, BTU, NUE, FCX, K. E&P = ARX, CNQ, EOG, RRC, OVV, EQT, EXE; All market data as of June 30th 2025 as reported by Bloomberg; All Tourmaline data as per the EP plan and company filings

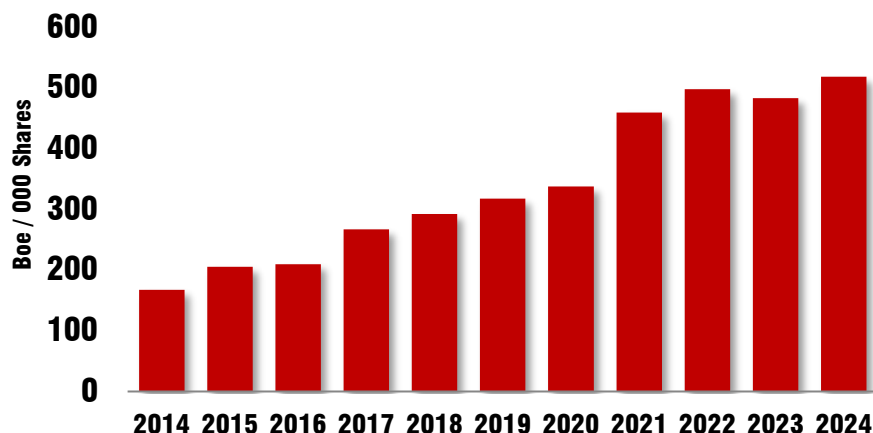
APPENDIX



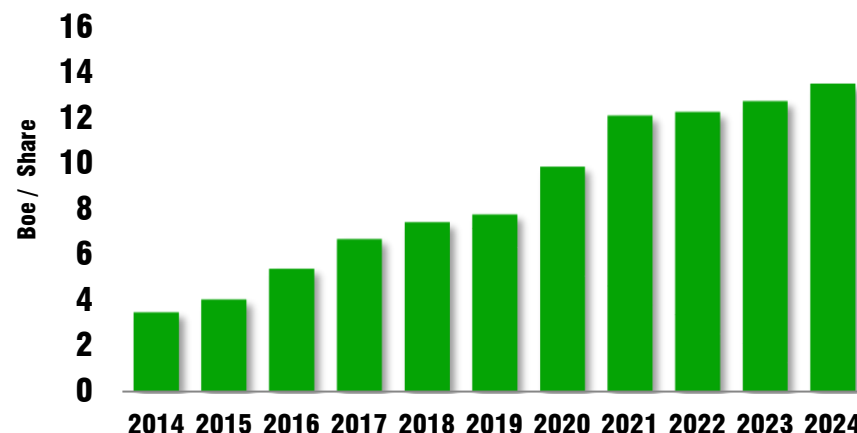
Historical EP Performance

Mar 2025

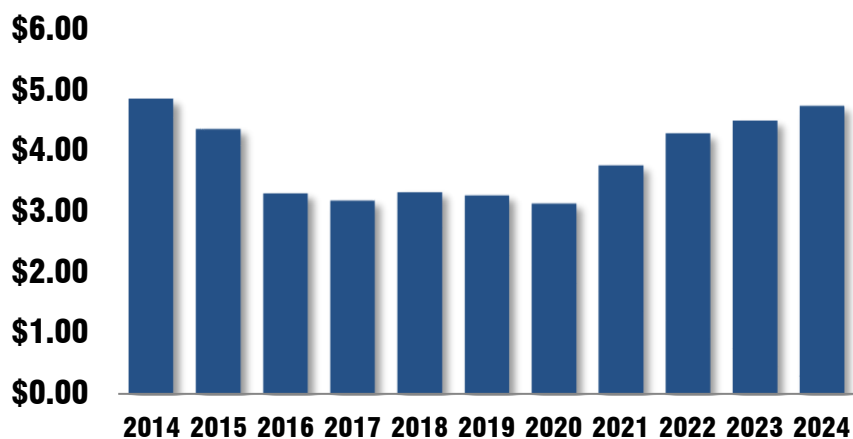
Production Per Share*



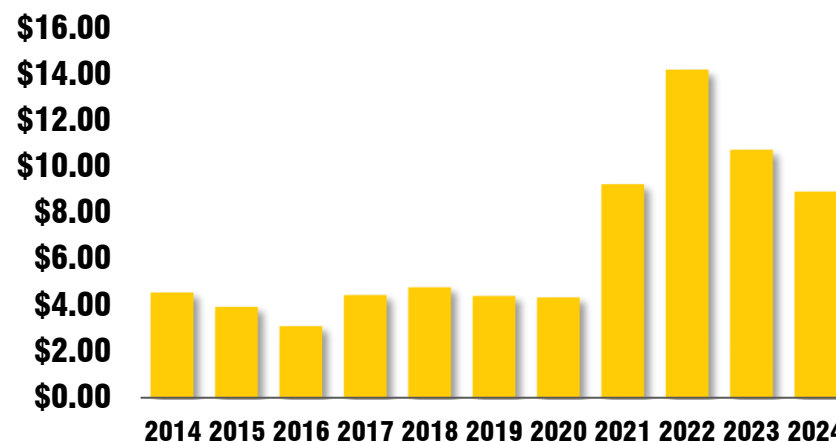
Reserves Per Share*



Operating Costs / BOE



Cash Flow Per Share

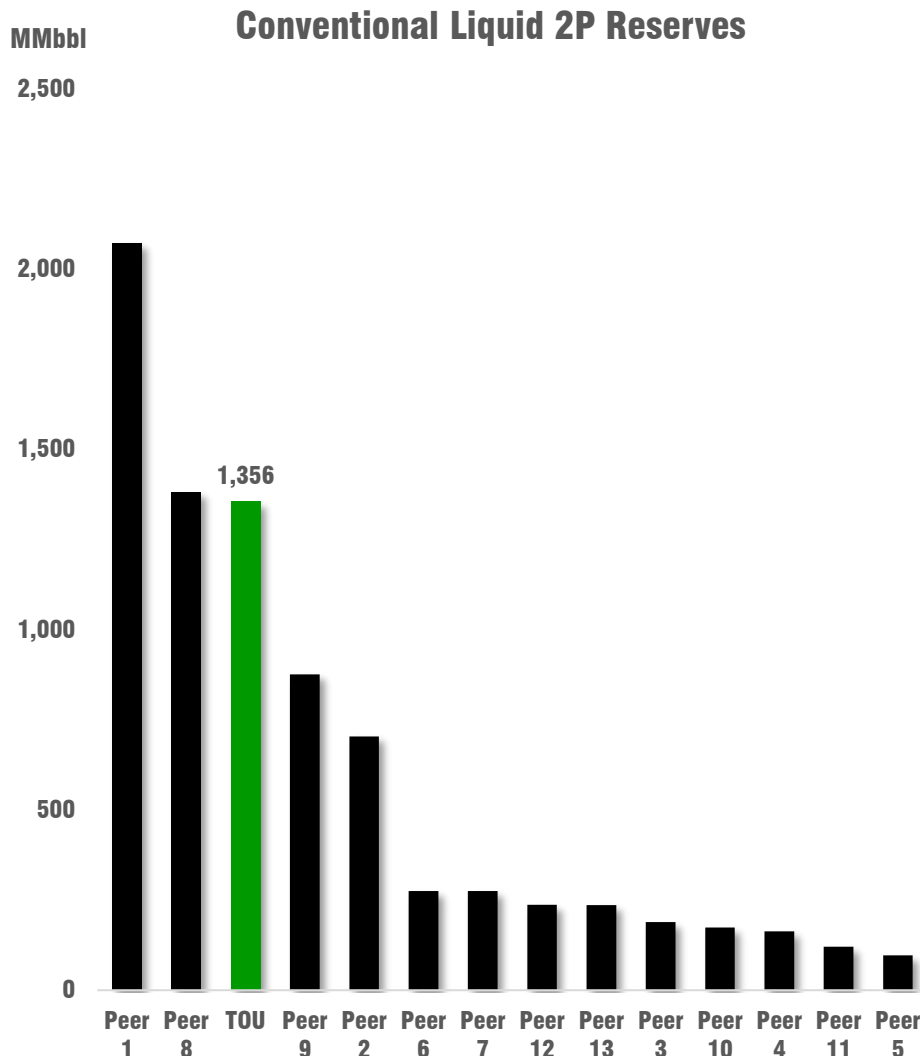
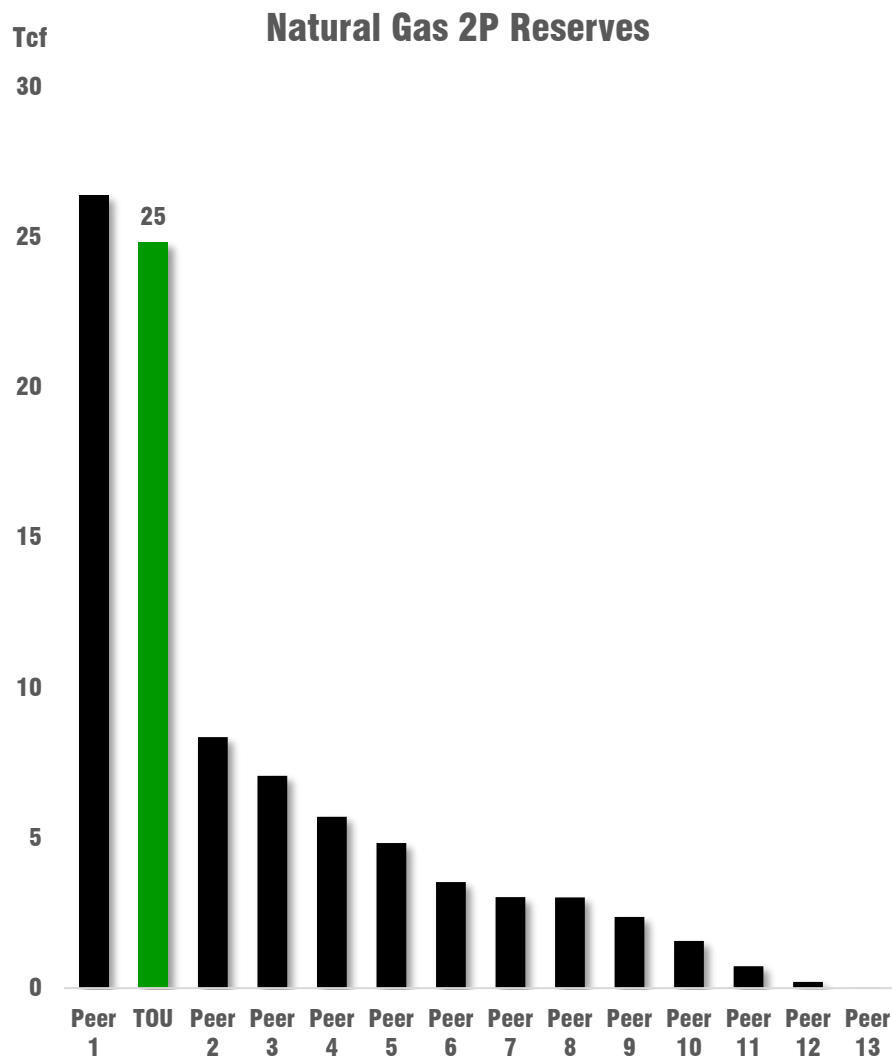


- 2014-2024 Production growth per share CAGR of 12%
- 2P BTax NPV 10% Reserve Value of \$41 billion
- Leading low capital and cash costs allow Tourmaline to grow profitably and pay a meaningful dividend in all parts of the natural gas price cycle

* Debt adjusted

Independently Recognized Canadian 2P Reserves⁽¹⁾

May 2025

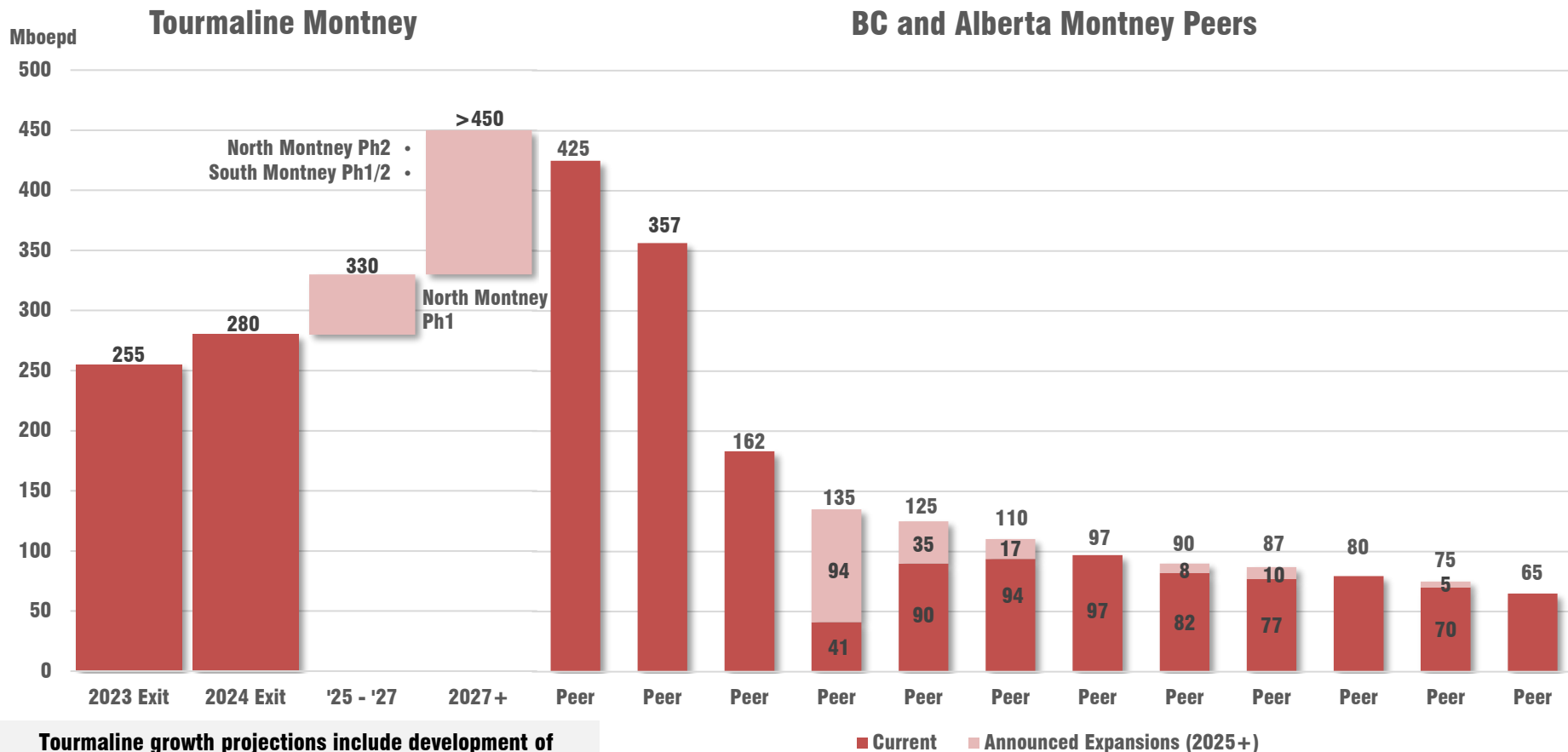


⁽¹⁾ Canadian Protocol, most recent disclosure. Peers include Advantage, ARC, Birchcliff, CNRL, Cenovus, Kelt, NuVista, Paramount, Peyto, Strathcona, Suncor, Tamarack, Whitecap / Veren (Proforma)

Significant Montney Growth Potential

July 2025

Tourmaline has access to significant potential Montney growth through fully delineated assets that are economic on current strip



Tourmaline growth projections include development of existing assets, all are fully delineated and are economic / full cycle profitable on current strip pricing. This analysis excludes Red Creek / Attachie, Noel, Tupper, Jedney, new pool delineation, and potential additional acquisitions.

Peer data as per most recent disclosure; Accumap, Peters & Co. research. Expansions include publicly announced growth, and/or budgeted volume growth.

Peers include AAV, ARX, BIR, CNQ, COP, Mitsubishi (Diamond Gas), MUR, NVA, OVV, Petronas JV, Shell Canada

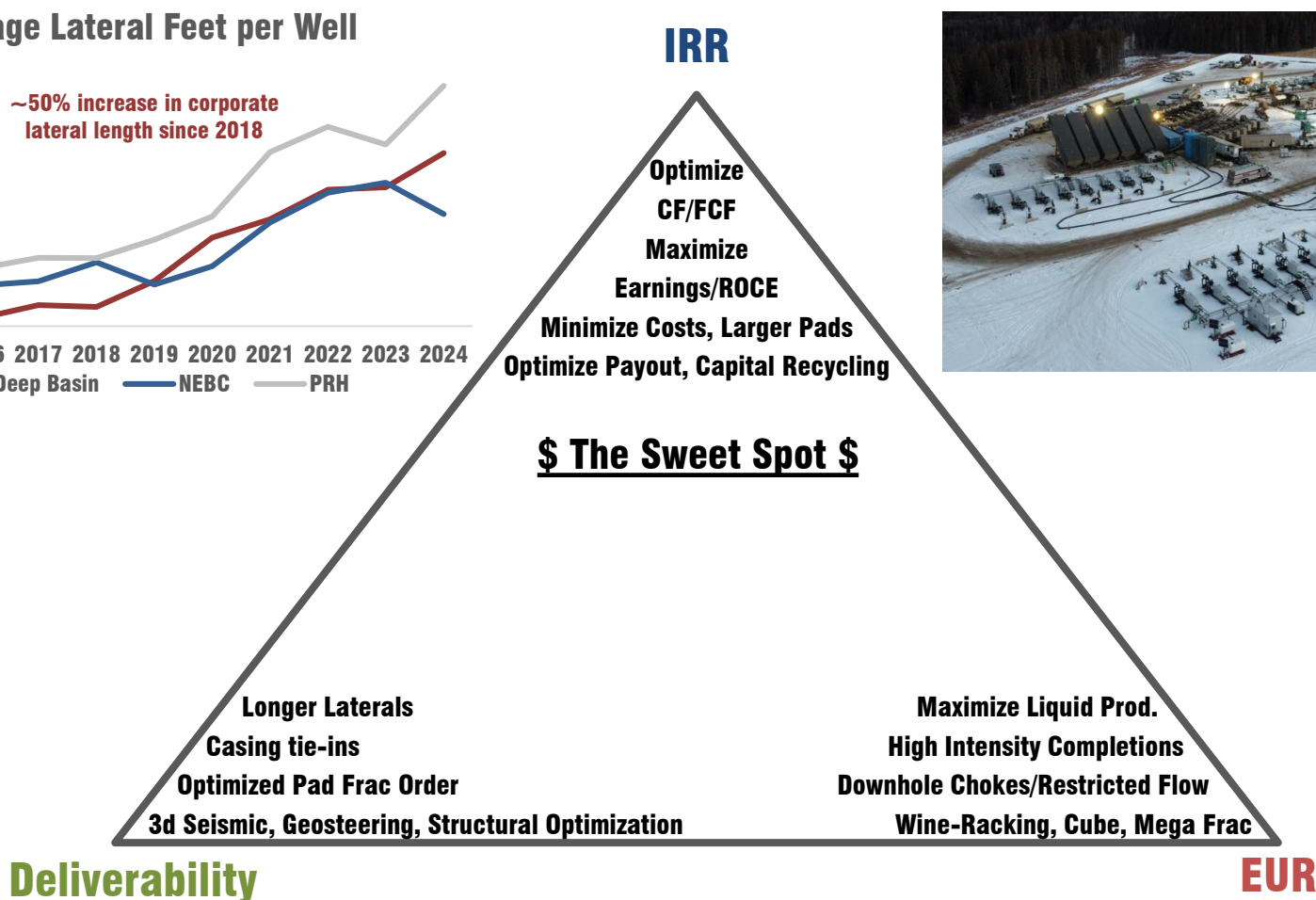
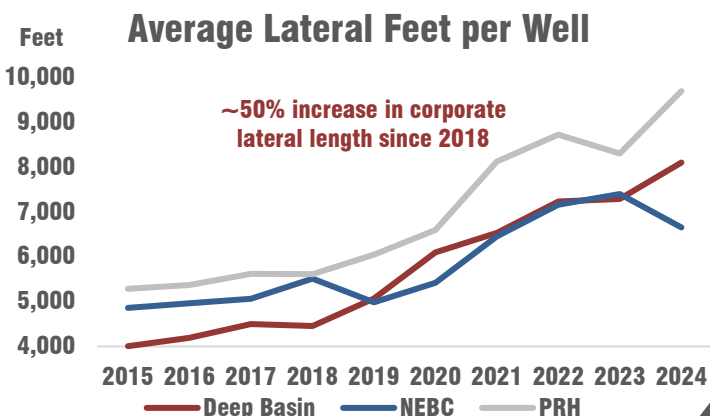


TOURMALINE
OIL CORP.

The Ever-Evolving Tourmaline Development Approach

Mar 2025

In the Alberta Deep Basin and the BC Montney Tourmaline is constantly seeking the balance between maximizing deliverability (growth), EUR (value), and overall economic return (CF/FCF). Tourmaline ultimately prioritizes IRR maximization, this results in faster well payouts, lower supply costs, and a free cash flow flywheel that can service both capital investment and capital return in all commodity price environments.



Gas Development Location Inventory and Economics⁽¹⁾

Mar 2025

	AB Deep Basin North & West <u>Horizontal</u>	AB Deep Basin South <u>Horizontal</u>	NEBC Gundy MNTN <u>Horizontal</u>	NEBC North MNTN <u>Horizontal</u>	NEBC South MNTN <u>Horizontal</u>	PRH Charlie Lake <u>Horizontal</u>	PRH Montney <u>Horizontal</u>
Total Well Costs (Drill, Case, Complete, \$ Million)	5.31	5.81	4.63	4.49	5.53	3.10	4.39
Average Reserves/Well (bcfe)	6.8	5.6	5.1	7.7	6.6	2.5	3.4
Lateral Length (metres)	2,250	2,900	2,300	2,400	2,650	2,250	2,250
Year 1 Production Rate ⁽²⁾	5.4 mmcfepd	3.8 mmcfepd	4.3 mmcfepd	4.5 mmcfepd	4.4 mmcfepd	262 boepd	568 boepd
Development Cost/boe	\$4.69	\$6.20	\$5.41	\$3.50	\$5.00	\$7.53	\$7.77
Operating Expenses/boe ⁽³⁾	\$3.23	\$4.92	\$2.14	\$6.37	\$2.49	\$9.10	\$7.53
Net Present Value @ 10% (000's)	\$6,001	\$6,003	\$8,768	\$9,012	\$8,268	\$4,811	\$4,124
Internal Rate of Return ⁽⁴⁾	76%	63%	338%	184%	104%	146%	124%
Payback Period (months)	17	18	7	10	14	10	12
Year 1 Gas Price ⁽⁵⁾	\$2.11	\$2.27	\$1.95	\$1.90	\$2.05	\$2.04	\$2.04
Future Development Locations ⁽⁶⁾	14,267	527	1,188	2,901	2,820	1,274	920

Notes:

(1) All amounts are before tax.

(2) Assumes on production date of January 1, 2025.

(3) Average operating expenses over the initial five years of production.

(4) Internal Rate of Return calculation is based on monthly cash flows.

(5) Independent Reserve Engineer January 1, 2025 escalated price forecast, adjusted for transportation, quality and heat content.

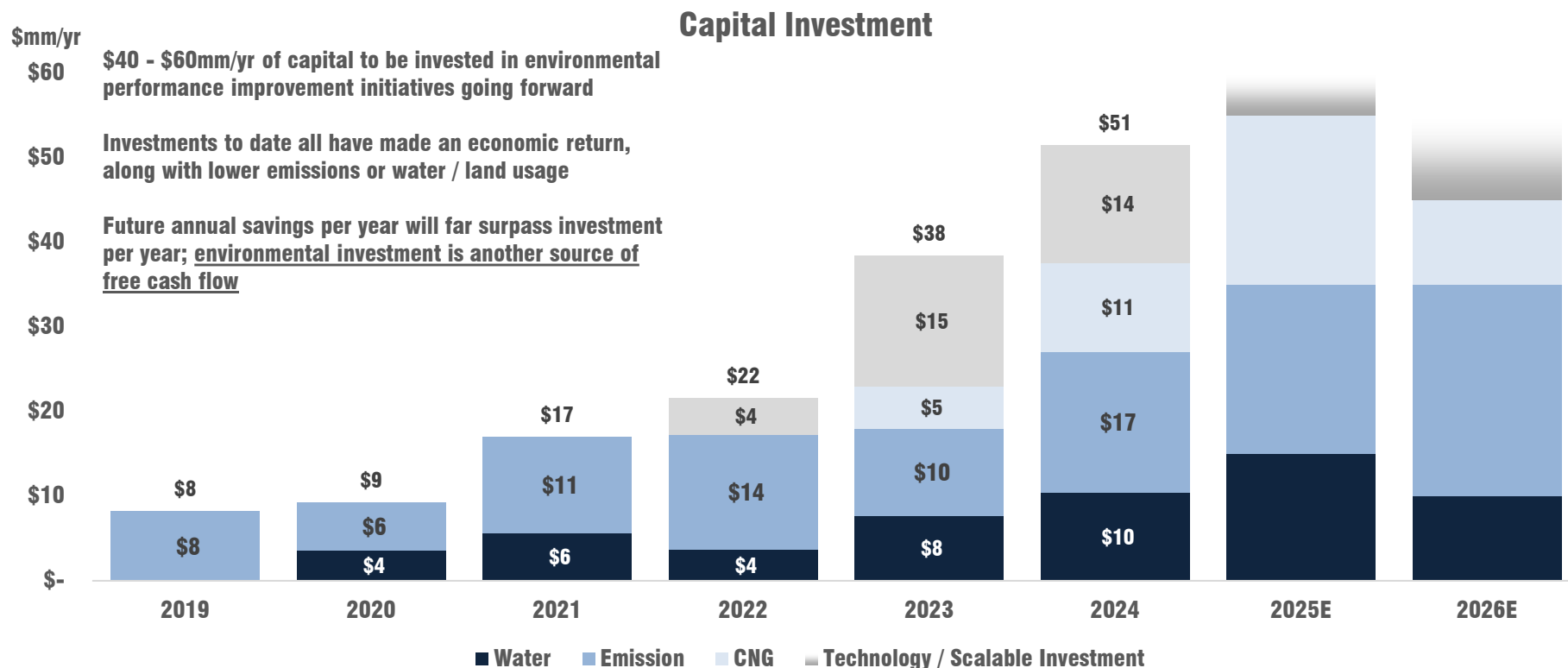
(6) See Schedule A.

Environmental Performance Investment

Mar 2025

Focusing on investment opportunities that maximize cost savings & environmental impact

- **Water:** recycling, & pipeline infrastructure; ~95% recycling in NEBC, advancing AB towards 100%
- **Air:** diesel displacement, pneumatic / venting reduction, power (highline), energy efficiency, CCUS, RNG, Methane ETC (Emission Testing Center)
- **CNG – Clean Energy / Tourmaline JV (\$70mm JDA – 15-20 stations over five years)**
- **Technology:** CCUS, NGIF, RNG, other initiatives



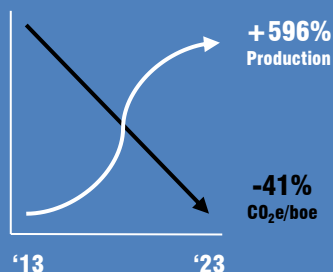
See Tourmaline Sustainability Report for more detail; forward looking estimates are illustrative only

Environmental Performance Improvement

Mar 2025

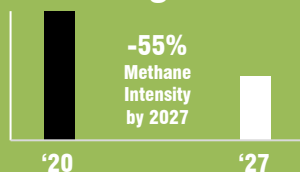
Tourmaline has been aggressively and successfully pursuing a comprehensive environmental performance improvement strategy for over seven years. The Company is systematically improving its performance and reducing the impact of all aspects of activities upon air, land and water.

Achievements



- 41% reduction in CO₂ emission intensity since 2013; NEBC Platinum rated by Project Canary⁽¹⁾
- 95% of completion water recycled from gas operations
- Initiation of methane reduction retrofit compliance plan in 2019; 3,700 controllers replaced
- 50% reduction in surface area per producing well
- Broad replacement of diesel in drilling and completion operations with natural gas
- Performed lifecycle assessments of both Sundown (NEBC) & Banshee (DB) natural gas production

Targets



- Targeting 55% reduction in methane emission intensity from 2020 levels by 2027
- Reduce corporate emissions intensity by 25% by 2027⁽²⁾, through the application of new, innovative technologies including the electrification of assets
- Targeting elimination of fresh water usage in well stimulation operations (NEBC ✓)

Initiatives

- ✓ Methane Mitigation
- ✓ Fuel Switching
- ✓ Energy Efficiency
- ✓ Water Recycling

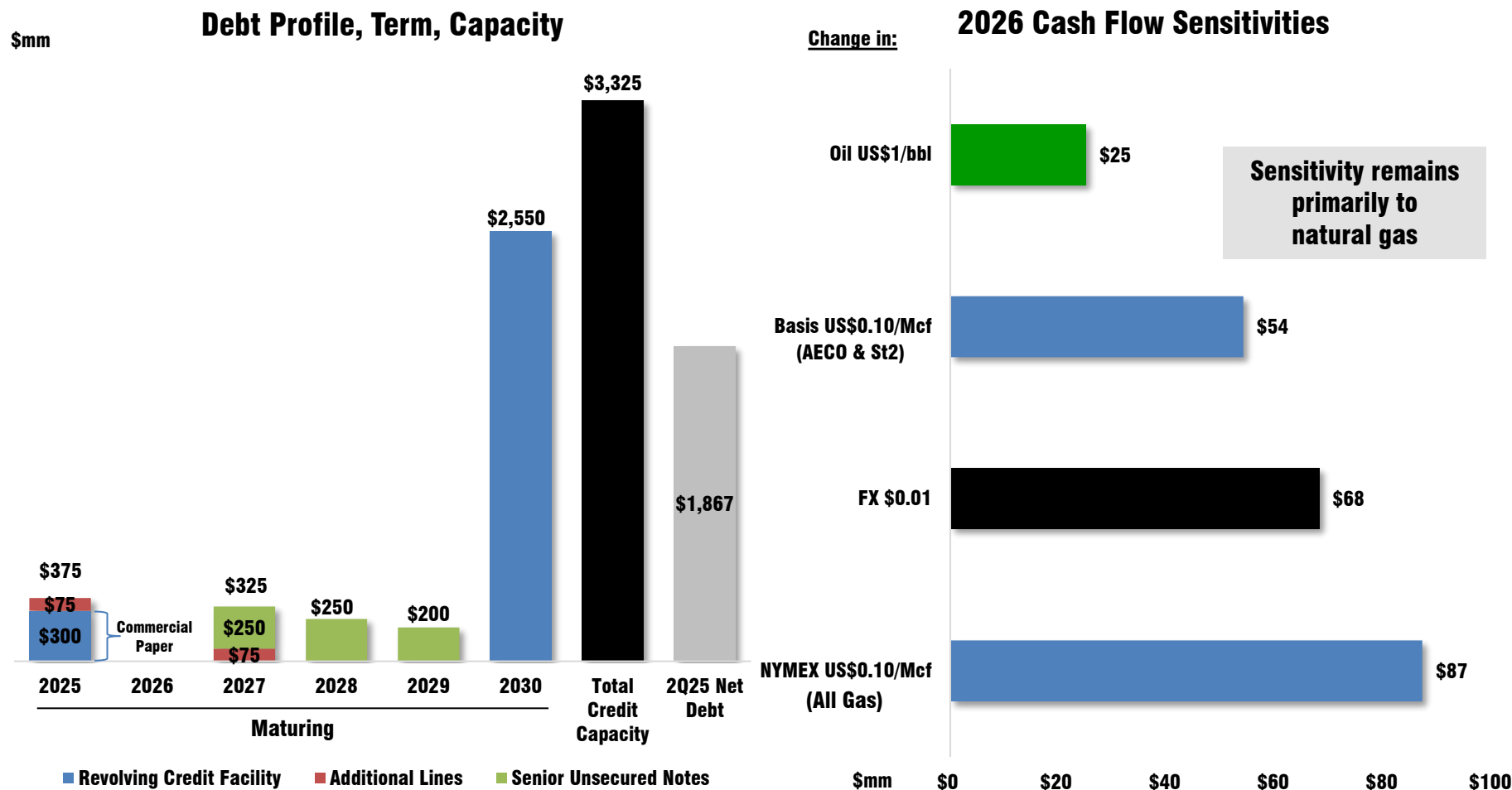
- Full top-down methane surveillance with aircraft & satellite. Replaced over 3,700 pneumatic devices
- All drilling/frac rigs/fleets have natural gas blending, 1 highline rig, 3 battery hybrids, 1 tier 4 frac fleet
- Waste heat recovery, compressor valve upgrades, battery hybrid gas plant
- Produced water recycling with current capacity of 585,000 m³ across 8 water recycling facilities & 13 produced water ponds.

Tourmaline Financial Position

Excellent Liquidity, Resiliency & Capacity

July 2025

Tourmaline has ample liquidity and capacity to weather adverse commodity prices



Tourmaline Technology Curve/Future Concepts, Requirements & Opportunities



- Alternative hz frac programs/processes
 - Concurrent pairs, delayed flow-backs etc.
- Novel drilling technology to reduce time/cost in drilling builds
- Refine drilling techniques/cost savings for frontal foothills Wilrich/Notikewin hz drlg
- Ball drop/sliding sleeve completion technique in vertical wells
- Understanding controls on Wilrich deliverability/develop predictive tools
- New shale/source rock plays
- Pasquia Hills oil shale recovery mechanisms
- Cost saving via novel frac water sourcing/recycling
- Waste heat recovery technology
- Utilizing gas fired turbines to reduce costs for drilling, completions, facilities
- New mud systems to reduce drilling times
- Improved horizontal stimulation techniques, new approaches to maximize deliverability and recovery
- Sour frac water sweetening technology
- Develop predictive reservoir/reserve tools for horizontal clastic gas wells
- Improved Wilrich seismic imaging in strat settings and Outer Foothills settings
- Paleozoic/New Deep Play concepts
- AI applications in geophysical interpretation, reservoir prediction and predictive drilling problem identification.

Schedule A

DRILLING LOCATIONS

Estimated Drilling Inventory

This presentation discloses drilling locations in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 25,462 (gross) locations disclosed in this presentation, 2,229 are proved undeveloped locations, 32 are proved non-producing locations, 1,711 are probable undeveloped locations, and 21,490 are unbooked. Proved producing wells, proved undeveloped locations, proved non-producing locations, probable undeveloped locations and probable non-producing locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ and Deloitte LLP as of December 31, 2024, and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

The following provides additional information on the Company's estimation of unbooked locations.

Schedule A continued

Deep Basin Horizontal well count :

- Total horizontal Deep Basin locations = 17,660 (1-2 wells per section per zone depending on zone)
- Less existing horizontals, and less 20% of existing vertical producers = 2,866
- Remaining Horizontal Locations = 14,794

Deep Basin vertical well count:

- Outer Foothills gross sections = 390; 90% accessible with 2 wells per section
- Less 119 Outer Foothills existing wells
- Remaining vertical locations = 383

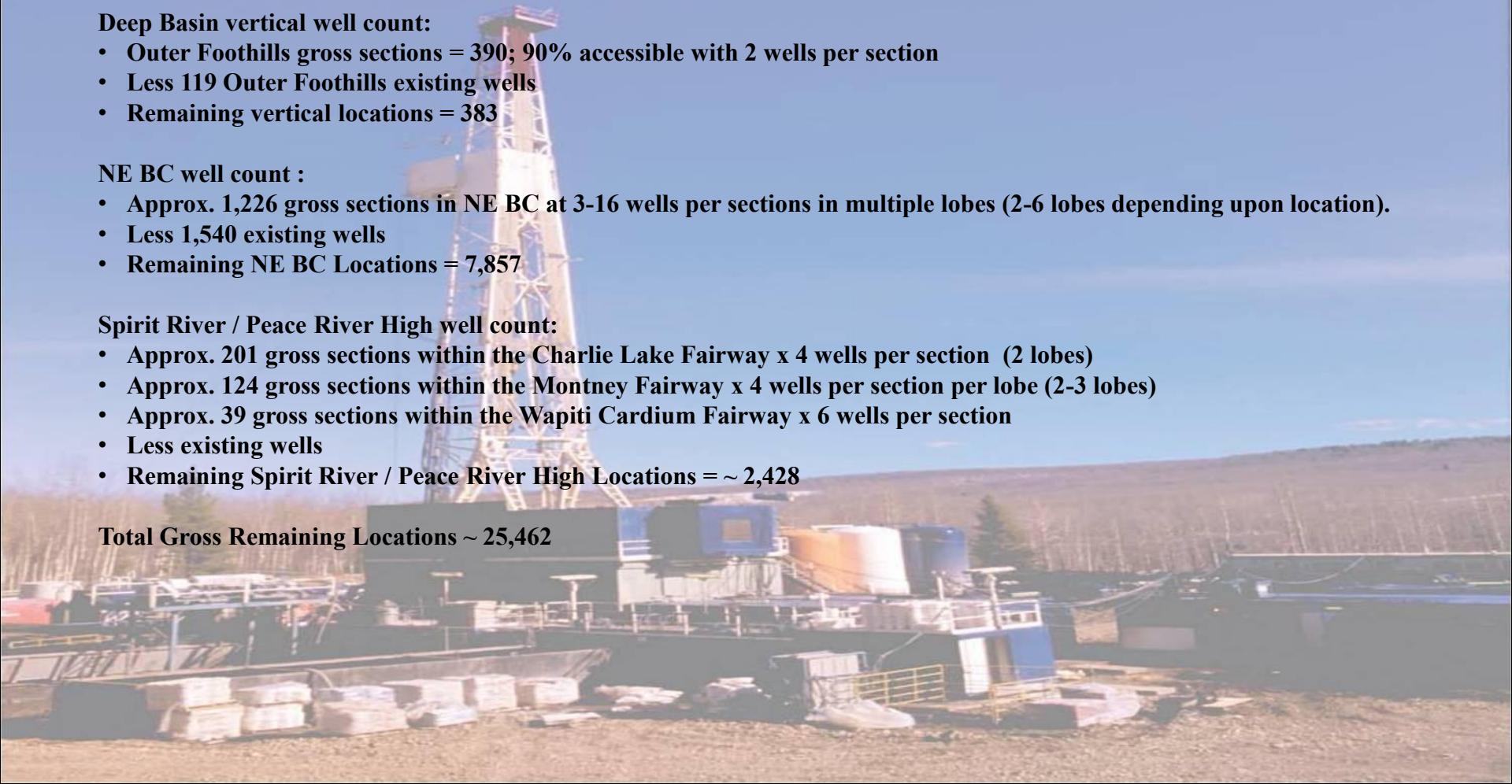
NE BC well count :

- Approx. 1,226 gross sections in NE BC at 3-16 wells per sections in multiple lobes (2-6 lobes depending upon location).
- Less 1,540 existing wells
- Remaining NE BC Locations = 7,857

Spirit River / Peace River High well count:

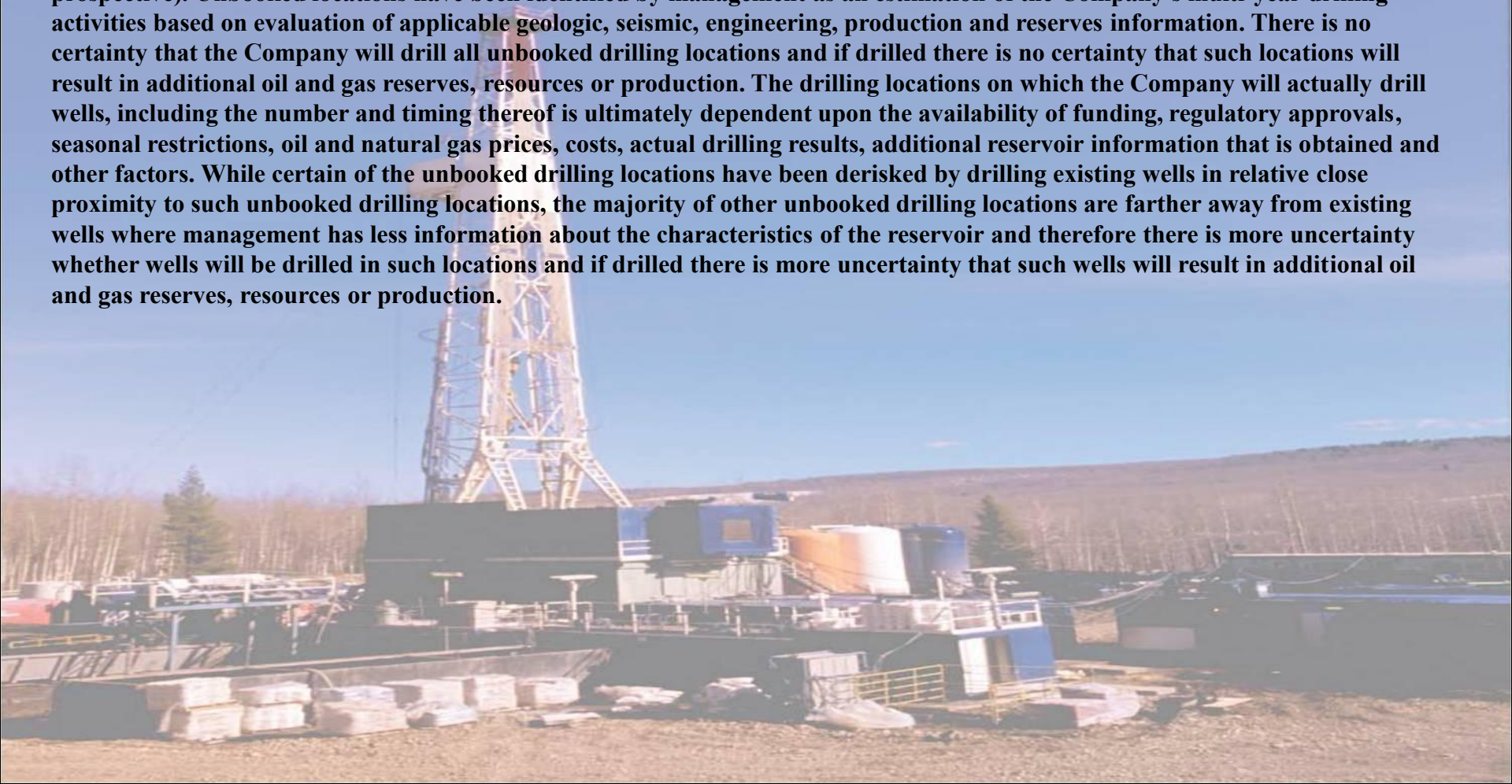
- Approx. 201 gross sections within the Charlie Lake Fairway x 4 wells per section (2 lobes)
- Approx. 124 gross sections within the Montney Fairway x 4 wells per section per lobe (2-3 lobes)
- Approx. 39 gross sections within the Wapiti Cardium Fairway x 6 wells per section
- Less existing wells
- Remaining Spirit River / Peace River High Locations = ~ 2,428

Total Gross Remaining Locations ~ 25,462



Schedule B

Prospective locations are unbooked locations that are not included in inventory. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.



Forward Looking Information

Certain information contained in this presentation constitutes forward-looking information within the meaning of applicable securities laws. This information relates to future events or the Company's future performance. All information other than information of historical fact is forward-looking information. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" and similar expressions are intended to identify forward-looking information. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon. This information speaks only as of the date of this presentation or, if applicable, as of the date specified in those documents specifically referenced herein. In addition, this presentation may contain forward-looking information attributed to third-party sources.

Without limitation of the foregoing, this presentation contains forward-looking information pertaining to the following: the reserve potential of the Company's assets; the anticipated production from the Company's assets and anticipated future cash flows from such assets; the Company's growth strategy and opportunities; the Company's capital exploration and development programs and future capital requirements; the estimated quantity and value of the Company's proved and probable reserves; expectations regarding the ability to raise capital and to continually add to reserves; the Company's estimates of future interest and foreign exchange rates; the Company's environmental considerations; the Company's assumptions regarding commodity prices; the Company's expectations regarding reduction in its operating costs; the timing of commencement of certain of the Company's operations and the level of production anticipated by the Company; the potential for production disruption and constraints; supply and demand fundamentals for crude oil and natural gas; the Company's access to adequate pipeline and other gathering, transportation and processing capacity; the Company's access to third-party infrastructure; the Company's drilling and recompletion plans; the Company's expected capital expenditures; expected debt levels and credit facilities; industry conditions pertaining to the oil and gas industry; the Company's plans for, and results of, exploration and development activities; the planned construction of the Company's gathering, transportation and processing facilities and related infrastructure; the timing for receipt of regulatory approvals; the Company's treatment under governmental regulatory regimes and tax laws and potential changes in such regimes and laws; the Company's future general and administrative expenses; and the Company's expectations regarding having adequate human resource staffing.

Forward Looking Information

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 interest rates and currency exchange rates; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the regulatory framework governing royalties, taxes and environmental matters; the Company's ability to market production of oil and natural gas successfully; the Company's future production levels; the applicability of technologies for recovery and production of the Company's reserves; the recoverability of the Company's reserves; future capital expenditures to be made by the Company; future cash flows from production meeting the expectations stated in this presentation; future sources of funding for the Company's capital program; the Company's future debt levels; geological and engineering estimates in respect of the Company's reserves; the geography of the areas in which the Company is conducting exploration and development activities; the impact of competition on the Company; and the Company's ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in this forward-looking information as a result of a number of factors including the risk factors set forth in the Company's reports and documents on file with Canadian securities regulatory authorities at www.sedarplus.ca or the Company's website at www.tourmalineoil.com, which risk factors should not be construed as exhaustive. See specifically "Forward-Looking Statements" and "Risk Factors" in the Company's most recently filed Annual Information Form and "Forward-Looking Statements" in the Company's most recently filed Management's Discussion and Analysis.

Included in this presentation are estimates of the Company's 2025-2031 cash flow, free cash flow and cash flow per share which are based on various assumptions as to production levels, commodity prices, the anticipated receipt of drilling permits and other assumptions and in the case of the years other than 2025, such estimates 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. To the extent such estimates constitute a financial outlook, they were approved by management of the Company in July 2025 and are included to provide readers with an understanding of the Company's anticipated cash flow based on the capital expenditures and other assumptions described and readers are cautioned that the information may not be appropriate for other purposes.

In addition, 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. See also "Statement of Reserves Data and Other Oil and Gas Information" and "Certain Reserves Data Information" in the Company's Annual Information Form.

Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed herein or otherwise and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless specifically required to do so pursuant to applicable law.

Forward Looking Statement Advisories

Oil and Gas Advisories

Certain crude oil and natural gas liquids ("NGLs") volumes have been converted to millions of cubic feet equivalent ("mmcf") or thousands of cubic feet equivalent ("mcf") on the basis of one barrel ("bbl" of crude oil or NGLs to six thousand cubic feet ("mcf") of natural gas. Also, certain natural gas volumes have been converted to barrels of oil equivalent ("boe"), thousands of boe ("mboe") or millions of boe ("mmboe") using the same equivalency measure. Such equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

This presentation contains disclosure regarding finding and development costs. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

The estimated net present values disclosed in this presentation do not represent fair market value.

Unless otherwise expressly stated, the information in this presentation pertaining to future drilling locations or drilling inventories is based solely on internal estimates made by management and such locations have not been reflected in any independent reserve or resource evaluations and have not been recognized as reserves or resources as defined in NI 51-101. See Schedule A - Drilling Locations.

Similarly, unless otherwise expressly stated, the information in this presentation pertaining to targeted reserve volumes from future drilling is intended to indicate that in making its internal drilling decisions, the Company seeks to target drilling locations that, based on previous drilling results and its own internal assessments, it believes will on average ultimately generate the indicated volumes.

Initial Production Rates

Any references to initial production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter and are not necessarily indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. Such rates are based on field estimates and may be based on limited data available at this time.

Non-GAAP and Other Financial Measures

This presentation includes references to "cash flow", "capital expenditures", "E&P capital program" and "free cash flow" which are considered "non-GAAP financial measures" and the terms "cash flow per diluted share" and "cash flow per boe" which are considered "non-GAAP financial ratios". These terms do not have a standardized meaning prescribed by GAAP. In addition, this news presentation contains the terms "adjusted working capital" and "net debt", which are considered "capital management measures" and do not have standardized meanings prescribed by GAAP. Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Investors are cautioned that these measures should not be construed as an alternative to or more meaningful than the most directly comparable GAAP measures in evaluating the Company's performance. Additional information on these terms are included in the Company's most recently filed Management's Discussion and Analysis (See "Non-GAAP and Other Financial Measures" therein) and other reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.ca) or Tourmaline's website (www.tourmalineoil.com).

Forward Looking Statement Advisories

Non-GAAP Financial Measures

Cash Flow

Management uses the term “cash flow” for its own performance measure and to provide shareholders and potential investors with a measurement of the Company’s efficiency and its ability to generate the cash (net of current income taxes) necessary to fund its future growth expenditures, to repay debt or to pay dividends. The most directly comparable GAAP measure for cash flow is cash flow from operating activities. A summary of the reconciliation of cash flow from operating activities to cash flow, is set forth below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(000s)	2025	2024	2025	2024
Cash flow from operating activities (per GAAP)	\$ 745,049	\$ 696,011	\$ 1,833,360	\$ 1,336,628
Current income tax (expense) recovery	42,933	(13,549)	5,051	(45,207)
Current income tax paid	18,932	38,368	18,932	487,543
Change in non-cash working capital	15,917	34,287	(71,466)	(152,703)
Cash flow	\$ 822,831	\$ 755,117	\$ 1,785,877	\$ 1,626,261

Capital Expenditures

Management uses the term "capital expenditures" as a measure of capital investment in exploration and production activity, as well as property acquisitions and dispositions, and such spending is compared to the Company's annual budgeted capital expenditures. The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures, is set forth below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(000s)	2025	2024	2025	2024
Cash flow used in investing activities (per GAAP)	\$ 803,220	\$ 515,082	\$ 1,517,299	\$ 1,099,311
Change in non-cash working capital	(297,981)	(220,977)	(187,042)	(248,961)
Capital expenditures	\$ 505,239	\$ 294,105	\$ 1,330,257	\$ 850,350

Forward Looking Statement Advisories

Non-GAAP Financial Measures (con't)

E&P Capital Program

Management uses the term "E&P Capital Program" as a measure of capital investment in exploration and production activity, and such spending is compared to the Company's annual budgeted exploration and production expenditures. The most directly comparable GAAP measure for exploration and production spending is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to exploration and development expenditures, is set forth below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(000s)	2025	2024	2025	2024
Cash flow used in investing activities (per GAAP)	\$ 803,220	\$ 515,082	\$ 1,517,299	\$ 1,099,311
Change in non-cash working capital	(297,981)	(220,977)	(187,042)	(248,961)
Property acquisitions	–	(23,169)	(12,143)	(23,581)
Proceeds from divestitures	724	50,728	1,747	56,225
Other	(16,190)	(15,061)	(32,356)	(27,692)
Exploration and production expenditures	\$ 489,773	\$ 306,603	\$ 1,287,505	\$ 855,302

Free Cash Flow

Management uses the term "free cash flow" for its own performance measure and to provide shareholders and potential investors with a measurement of the Company's efficiency and its ability to generate the cash necessary to fund its future growth expenditures, to repay debt and provide shareholder returns. Free cash flow is defined as cash flow less capital expenditures, excluding acquisitions and dispositions. Free cash flow is prior to dividend payment. The most directly comparable GAAP measure for cash flow is cash flow from operating activities. See "Non-GAAP Financial Measures – Cash Flow" and "Non-GAAP Financial Measures – Capital Expenditures" above.

	Three Months Ended June 30,		Six Months Ended June 30,	
(000s)	2025	2024	2025	2024
Cash flow	\$ 822,831	\$ 755,117	\$ 1,785,877	\$ 1,626,261
Capital expenditures	(505,239)	(294,105)	(1,330,257)	(850,350)
Property acquisitions	–	23,169	12,143	23,581
Proceeds from divestitures	(724)	(50,728)	(1,747)	(56,225)
Free Cash Flow	\$ 316,868	\$ 433,453	\$ 466,016	\$ 743,267

Forward Looking Statement Advisories

Non-GAAP Financial Measures (con't)

Operating Netback

Management uses the term “operating netback” as a key performance indicator and one that is commonly presented by other oil and natural gas producers. Operating netback is defined as the sum of commodity sales from production, premium on risk management activities and realized gains (loss) on financial instruments less the sum of royalties, transportation costs and operating expenses. A summary of the reconciliation of operating netback from commodity sales from production, which is a GAAP measure, is set forth below:

(000s)	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
Commodity sales from production	\$ 1,134,466	\$ 1,104,940	\$ 2,592,033	\$ 2,579,319
Premium on risk management activities	262,646	179,627	600,255	246,972
Realized gain on financial instruments	108,937	128,125	205,354	212,570
Royalties	(90,328)	(127,466)	(269,487)	(277,937)
Transportation costs	(282,803)	(253,610)	(600,000)	(535,663)
Operating expenses	(289,467)	(246,243)	(585,128)	(505,476)
Operating netback	\$ 843,451	\$ 785,373	\$ 1,943,027	\$ 1,719,785

Forward Looking Statement Advisories

Non-GAAP Financial Ratios

Operating Netback per-boe

Management calculates “operating netback per-boe” as operating netback divided by total production for the period. Operating netback per-boe is a key performance indicator and measure of operational efficiency and one that is commonly presented by other oil and natural gas producers. A summary of the calculation of operating netback per boe, is set forth below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(\$/boe)	2025	2024	2025	2024
Revenue, excluding processing income	\$ 26.66	\$ 27.63	\$ 29.83	\$ 28.94
Royalties	(1.60)	(2.49)	(2.37)	(2.65)
Transportation costs	(5.01)	(4.96)	(5.27)	(5.10)
Operating expenses	(5.12)	(4.82)	(5.14)	(4.81)
Operating netback	\$ 14.93	\$ 15.36	\$ 17.05	\$ 16.38

Cash Flow per-boe

Management uses cash flow per boe to highlight how much cash flow is generated by each boe produced. The ratio is calculated by dividing cash flow by total production for the period. See “Non-GAAP Financial Measures – Cash Flow”.

Cash Flow per diluted share

Management uses cash flow per diluted share as a measurement of the Company’s efficiency and its ability to generate the cash necessary to fund its future growth expenditures, to repay debt or to pay dividends on a per diluted share basis. Cash flow per diluted share is calculated using cash flow divided by the weighted average diluted shares outstanding.

Forward Looking Statement Advisories

Capital Management Measures

Adjusted Working Capital

Management uses the term “adjusted working capital” for its own performance measures and to provide shareholders and potential investors with a measurement of the Company’s liquidity. A summary of the composition of adjusted working capital (deficit), is set forth below:

(000s)	As at June 30, 2025	As at December 31, 2024
Working capital (deficit)	\$ (417,244)	\$ (167,623)
Fair value of financial instruments – short-term (asset)	(264,428)	(315,365)
Lease liabilities – short-term	7,239	8,385
Decommissioning obligations – short-term	75,000	60,000
Unrealized foreign exchange in working capital – liability (asset)	2,723	(15,354)
Adjusted working capital (deficit)	\$ (596,710)	\$ (429,957)

Net Debt

Management uses the term “net debt”, as a key measure for evaluating its capital structure and to provide shareholders and potential investors with a measurement of the Company’s total indebtedness. A summary of the composition of net debt, is set forth below:

(000s)	As at June 30, 2025	As at December 31, 2024
Bank debt	\$ (571,648)	\$ (574,339)
Senior unsecured notes	(698,695)	(698,436)
Adjusted working capital (deficit)	(596,710)	(429,957)
Net debt	\$ (1,867,053)	\$ (1,702,732)