



A Proven Blueprint for Unlocking Value

August 2026

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All dollar figures included herein are presented in Canadian dollars, unless otherwise noted.

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and NGL reserves and the future cash flow attributed to such reserves.

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economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; and changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry. These risks and others are described in more detail in the Company's Annual Information Form for the year ended December 31, 2025, filed on SEDAR+ at www.SEDARPLUS.ca

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**THE AMERICAS'
FASTEST GROWING
COMPANIES 2026**



The Saturn Investment Opportunity (TSX: SOIL)



High-Quality Light Oil Weighted Assets, Free Funds Flow Generation and Per Share NAV Disconnect

01.

Diversified Asset Base

- >80% weighted to high-value light oil & liquids
- Consistent type curve outperformance (23% in 2025 / 22% in 2024)⁽³⁾
- Record 2025 production, adjusted funds flow & free funds flow⁽¹⁾

02.

Downside Protection

- Discounted valuation + 50% free funds flow yield^(1,2) at year-end '25
- Risk management protects the downside
- Flexible capital program allows rapid shifting in response to commodity prices

03.

Compelling Upside

- Potential for rerate with consistent performance & deleveraging
- Per share metrics significantly improved with NCIB & SIB
- Disconnect between market value and ~\$11/sh (1P) net asset value^(1,4) creates opportunity

1) See disclaimer "Information Regarding Non-GAAP and Other Financial Measures"

2) Based on Saturn's year end 2025 market cap and 2025 annual free funds flow

3) See disclaimer "Oil and Gas Advisories"

4) Based on 3CA pricing as at April 1, 2026

Corporate Profile



Saturn is a Low Decline, Low Royalty, Light Oil Producer Leveraging Our Saskatchewan Advantage

Capital Structure (\$C)

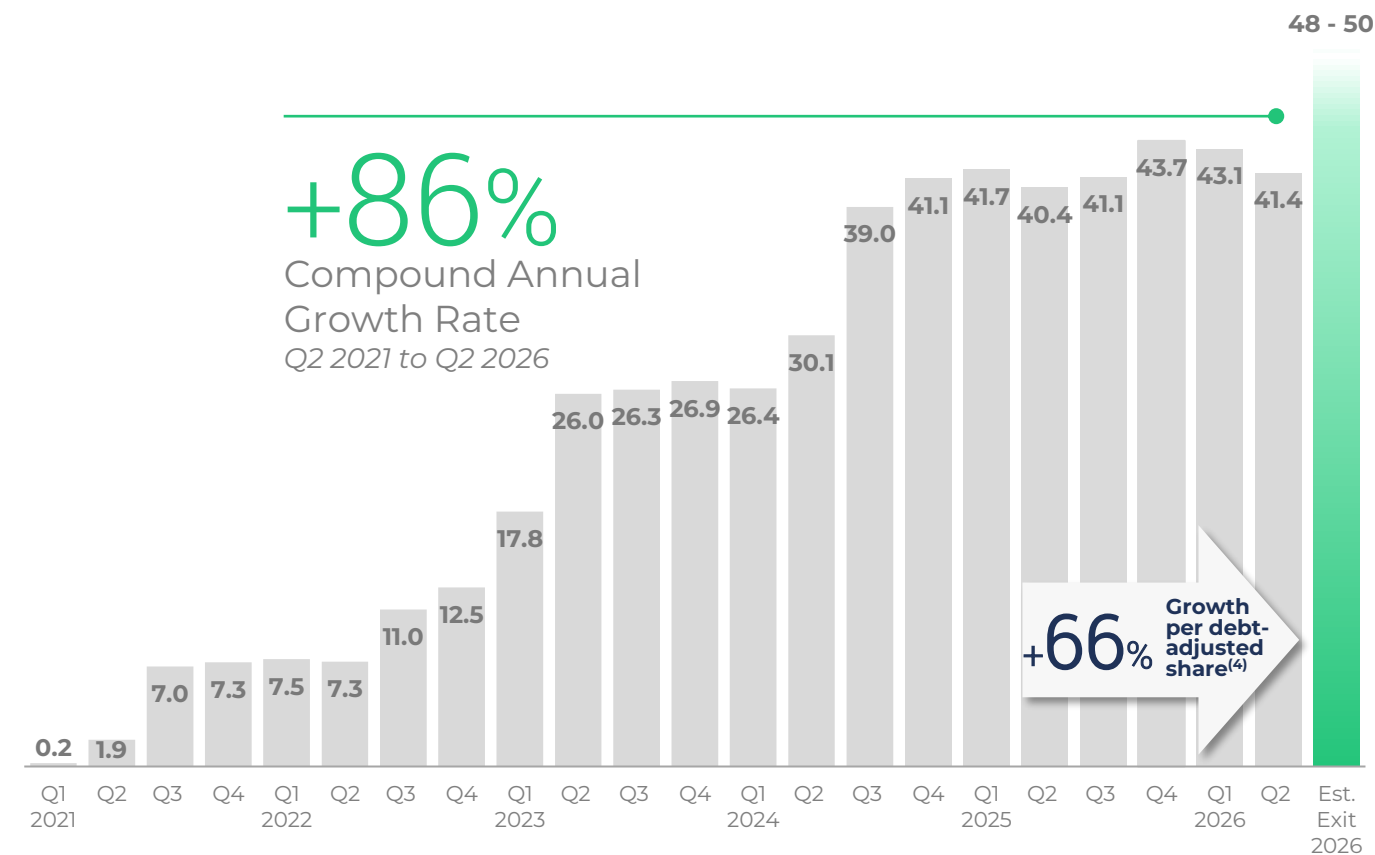
(TSX: **SOIL** | OTCQX: **OILSF**)

Shares Outstanding⁽¹⁾ (Basic)	178.0 MM
Basic Market Capitalization (Aug 12/26)	~\$1.0 B
Net Debt^(1,2)	\$761.6 MM
Enterprise Value (EV)	~\$1.8 B

Significant Shareholders⁽⁵⁾

GMT Capital Corp		30%
Libra Advisors LLC / Tandon Family Foundation		13%
Mackenzie Financial Corp.		6%
Equinox Partners		6%
1832 (Scotia Global Asset Management)		3%
The Huginn Fund		2%
Black Maple		2%
Bison Interests		2%
Penderfund Capital Management		2%
Nokomis Capital		2%
Charlestown Capital Advisors		1%
American Century Investment Mgmt		1%
Other Institutions		~2%
Visible Institutional Holders		~72%
Insiders		~2%

5-YEAR PRODUCTION HISTORY (MBoe/d)⁽³⁾



1) Net debt as at June 30, 2026 and shares outstanding as at Jul 29/26.

2) See disclaimer "Information Regarding Non-GAAP and Other Financial Measures"

3) Historical production breakdown by product available within the Company's MD&A's for the corresponding periods filed on SEDAR

4) Q2/26 over Q2/25. Calculated by converting quarter end net debt to shares, adding that to the basic shares outstanding at quarter end and dividing the total production in boe during the quarter by the debt adjusted shares.

5) Based on available data from IRWIN and other available ownership sources.

Our Blueprint for Value Creation



Simple Blueprint Saturn Follows to Enhance Size, Scale and Production Per Share Metrics



Acquire

mid-life cycle assets at attractive valuations & integrate seamlessly

Optimize

to reduce costs by streamlining operations, optimizing volumes & improving margins

Develop

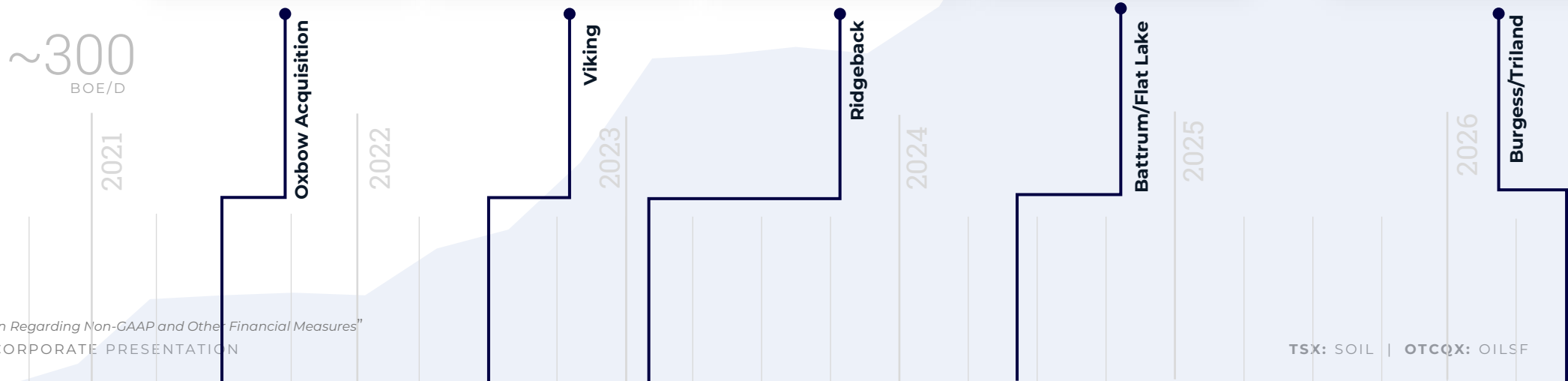
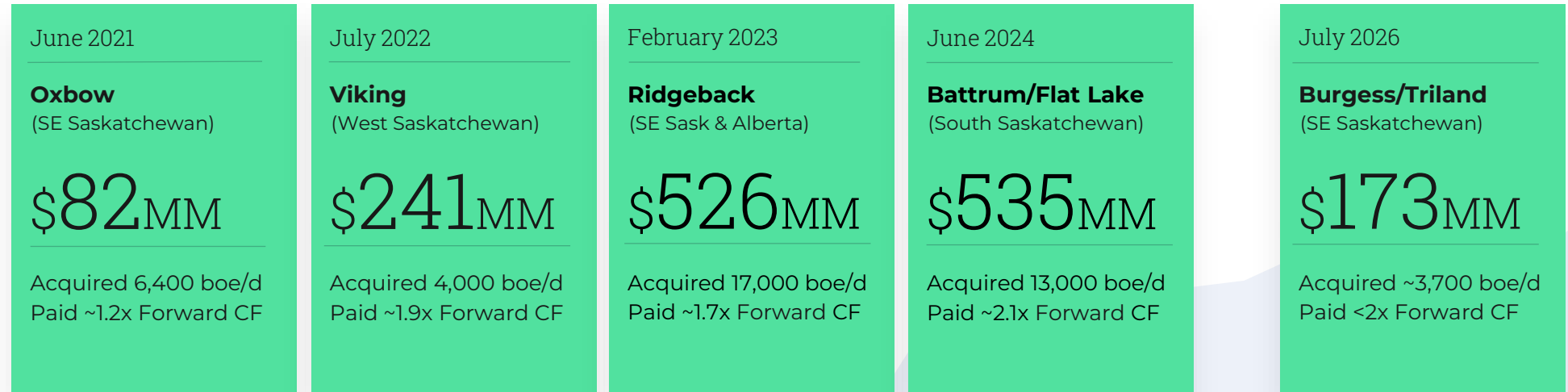
to expand reserves and locations, enhance asset performance & drive free funds flow⁽¹⁾ generation

Reduce Net Debt

target $\leq 1.0x$ net debt to adjusted EBITDA⁽¹⁾ 12-18 months post-closing and look to repeat

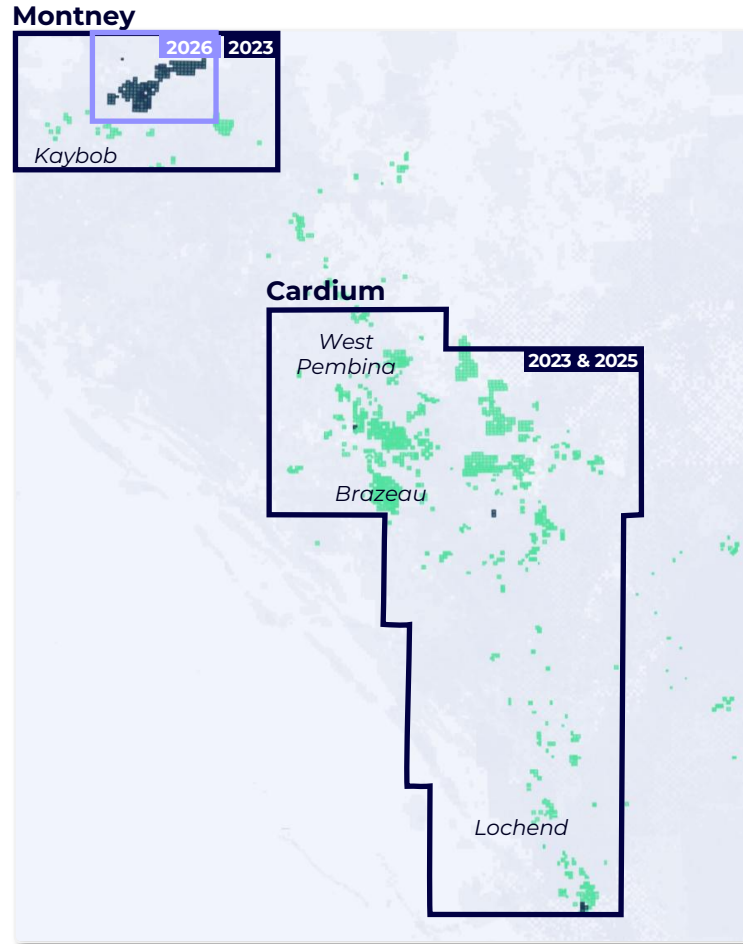
Five significant acquisitions, totaling **~\$1.6 billion**, drove growth from ~300 boe/d to a targeted 2026 exit of ~48-50,000 boe/d

~48-50,000
BOE/D 2026 EXIT TARGET



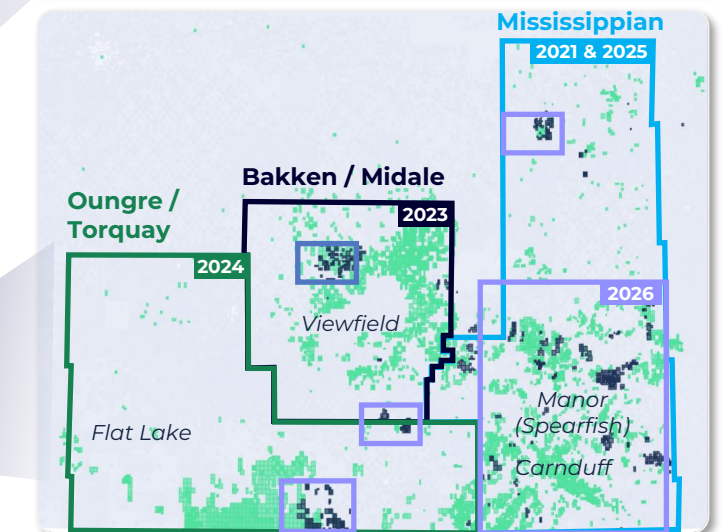
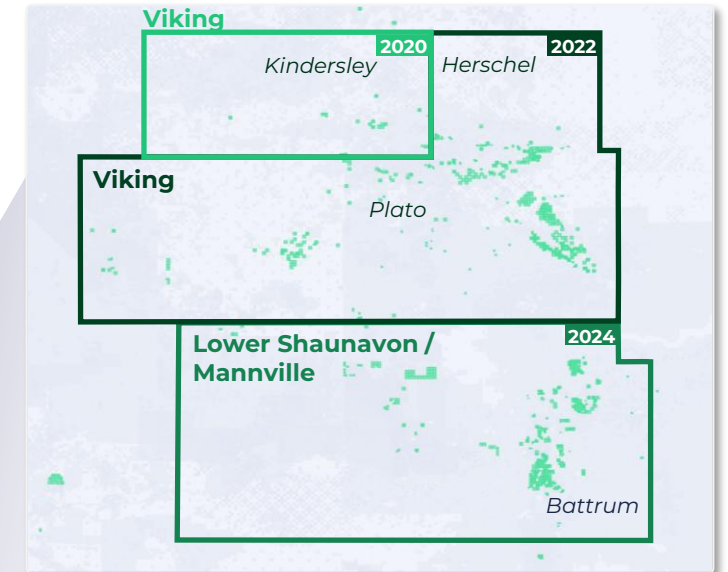
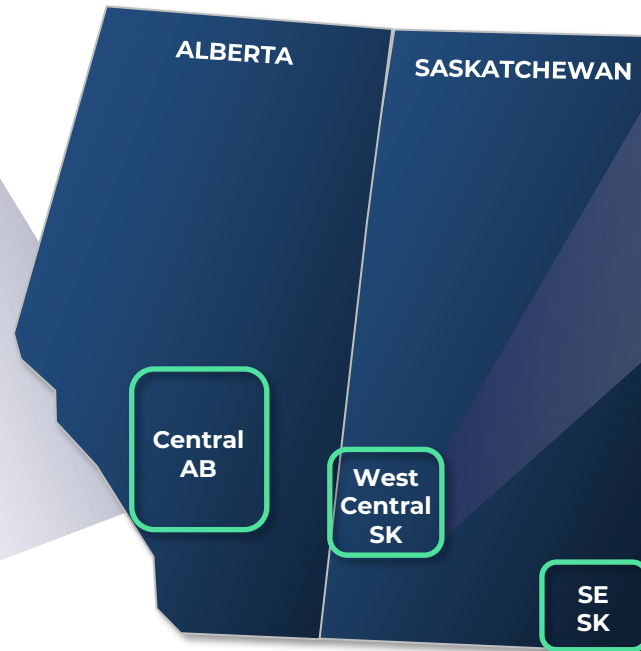
Oil-Weighted Assets Across Three Core Areas

Portfolio of Low-Decline, High-Return Plays Targets Multiple Stacked Oil Zones



~3,000
Identified
Drilling Locations¹⁾

~20 Yrs
Development
Inventory



Existing ■
Newly Acquired ■

Burgess Creek & Triland Core-Up Acquisitions



Continuation of Blueprint Strategy Expands Size & Scale in Core SE Saskatchewan Area

STRATEGIC HIGHLIGHTS

Light oil-weighted production in core SE Saskatchewan area increases scale & margins

- ~3,700 boe/d acquired (~97% light oil & liquids)⁽¹⁾
- Accretive netbacks

Acquired at low cash flow multiple & sub-PDP value on purchase price

- ~1.8x CF multiple⁽¹⁾
- ~80% of reserve PDP(NPV10)⁽²⁾

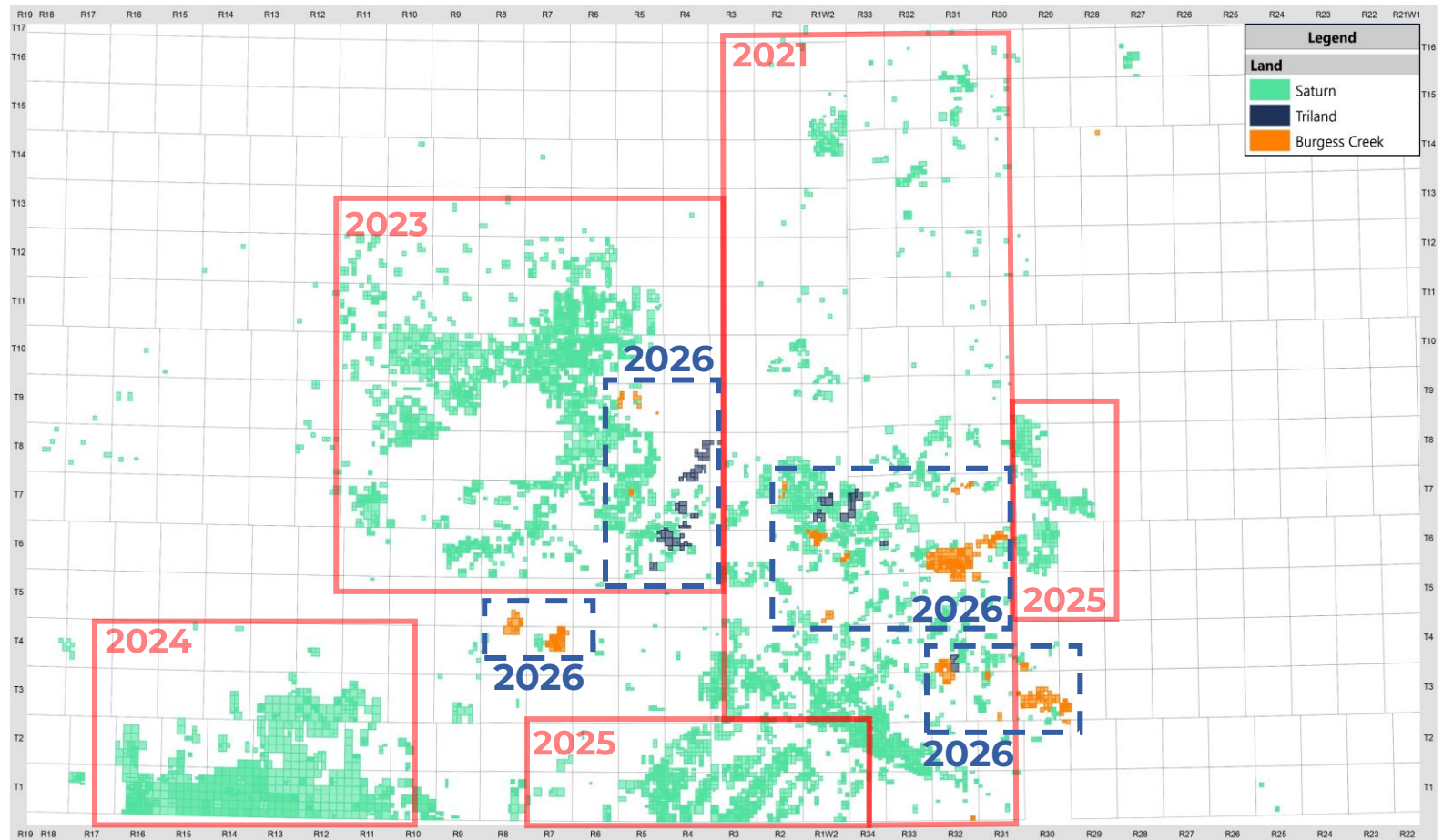
Assets bring deep location inventory with high-tier drilling targets

- >400 gross identified locations^(2,4)
- Includes >40 un-booked OHML locations^(2,4)

Synergies further enhance Saturn's 'Core-Up' strategy

- \$7MM identified synergies (NPV10 on PDP)⁽³⁾
- Expected opex reduction ~\$2.50/bbl⁽³⁾

BURGESS CREEK & TRILAND ASSETS FIT PERFECTLY WITHIN SATURN'S SE SK AREA



(1) Based on Q1/26 lease operating statements.

(2) Based on Company prepared internal projections.

(3) Forecast 2026 estimated net operating income (at US\$80 WTI)

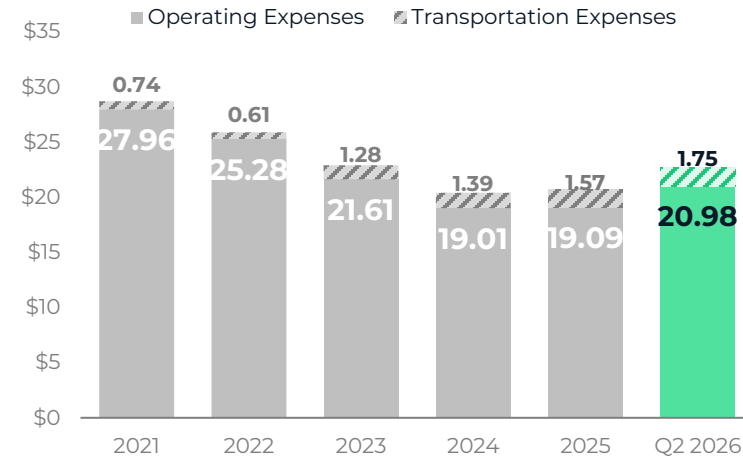
(4) See disclaimer "Identified Inventory"

Optimization: Controlling What We Can

Applying Saturn's Blueprint Contributes to Ongoing Margin Expansion

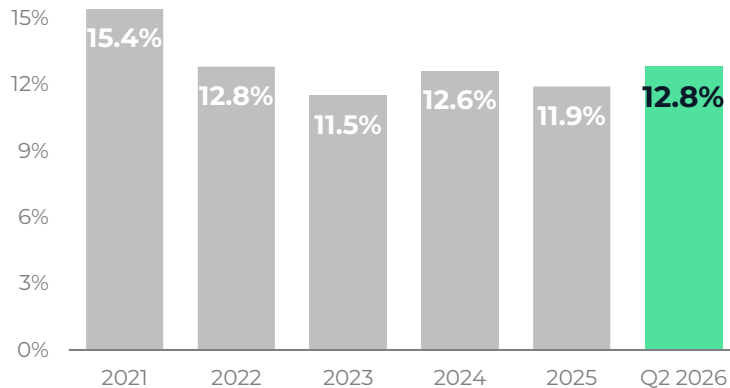


OPERATING & TRANSPORTATION COSTS⁽¹⁾ (\$/BOE)



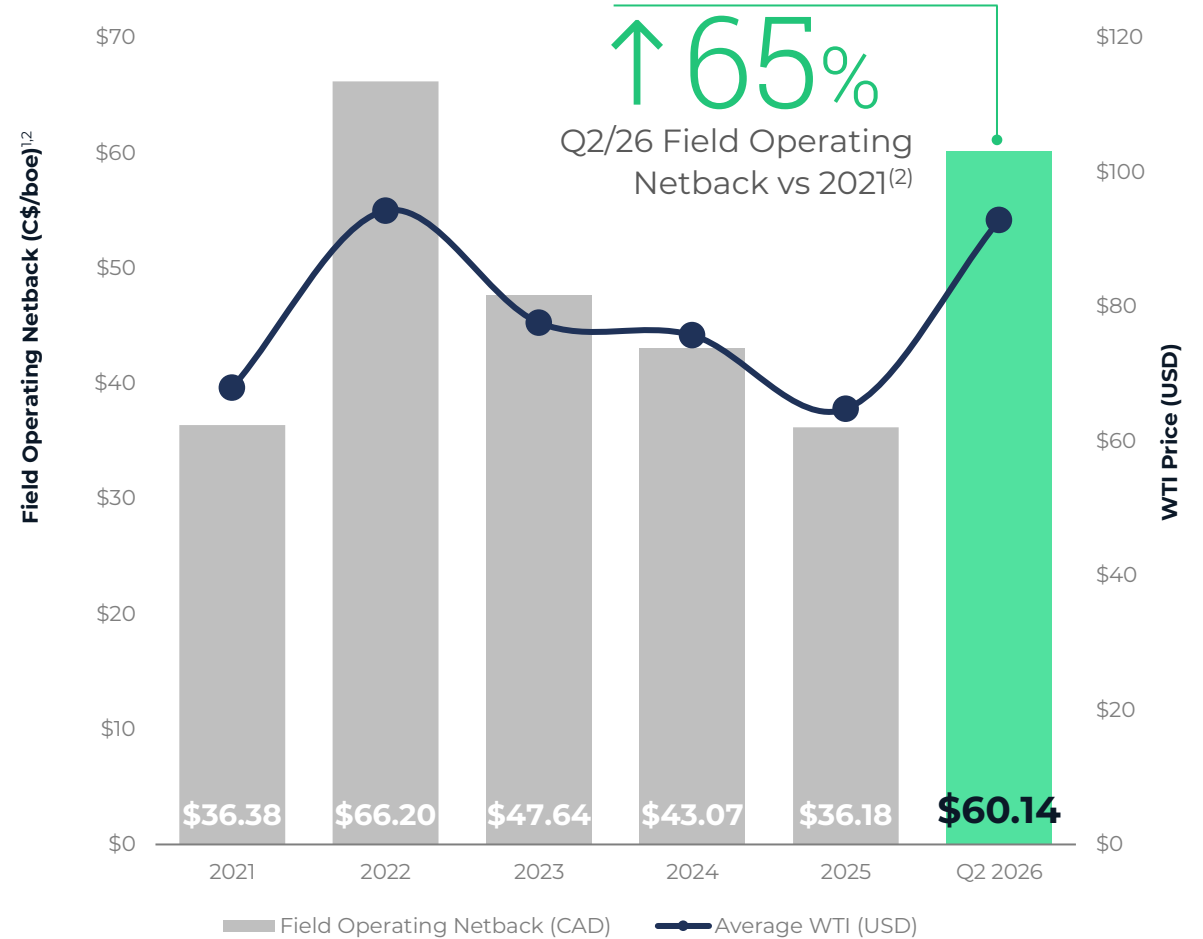
↓ 25%
Opex 2021 – Q2/26

ROYALTIES



↓ 17%
Royalties 2021 – Q2/26

FIELD OPERATING NETBACK^(1,2)



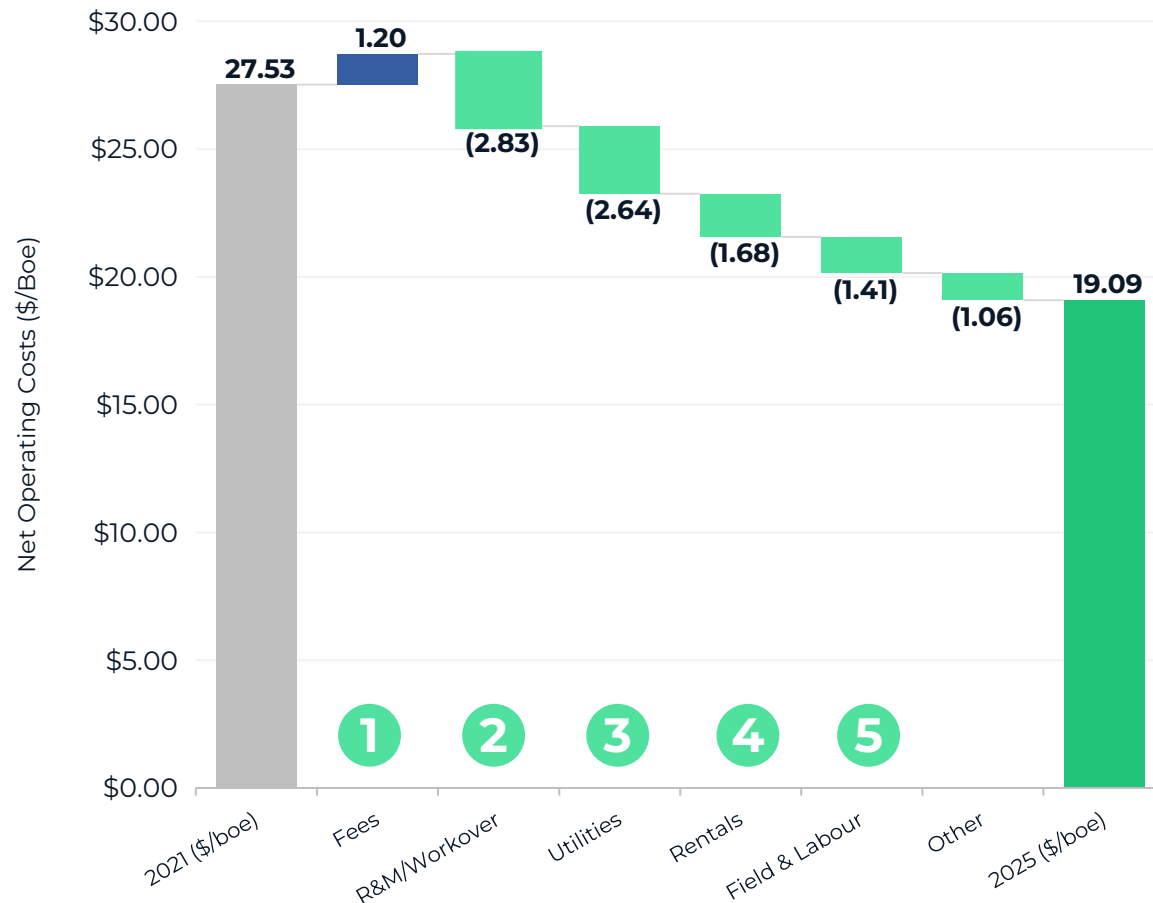
1) See disclaimer "Information Regarding Disclosure on Oil and Gas Operational Information and Non-IFRS Measures."
2) Field operating netback, before the impact of derivatives.

Operating Cost Reductions & Streamlining

Size and Scale Supports Ability to Capture Efficiencies



OPERATING COST⁽¹⁾ REDUCTION COMPONENTS
(2021 to 2025 - \$/BOE)



KEY OPEX⁽¹⁾ REDUCTION DRIVERS

1 Fees

- Increased due to gas processing fees on acquired properties

2 Repairs & Maintenance / Workovers

- Restored shut-in wells post-acquisition to increase production, and completed deferred maintenance to optimize facilities⁽²⁾

3 Utilities

- Secured lower utility rates through hedge contracts, supported by SK Carbon tax elimination
- Production volumes added in AB due to drilling benefits from competitive utility rates
- Reduced utility / energy usage following sale of Deer Mountain

4 Rentals

- Higher production reduces per unit fixed costs (lower \$/boe)
- Lower rental costs per unit in AB due to incremental production volumes added following drilling

5 Field & Labour

- Reflects synergy capture in key operating regions, as we are able to streamline headcount and reduce overhead as we core-up
- Per unit fixed costs decline as production increases (lower \$/boe)

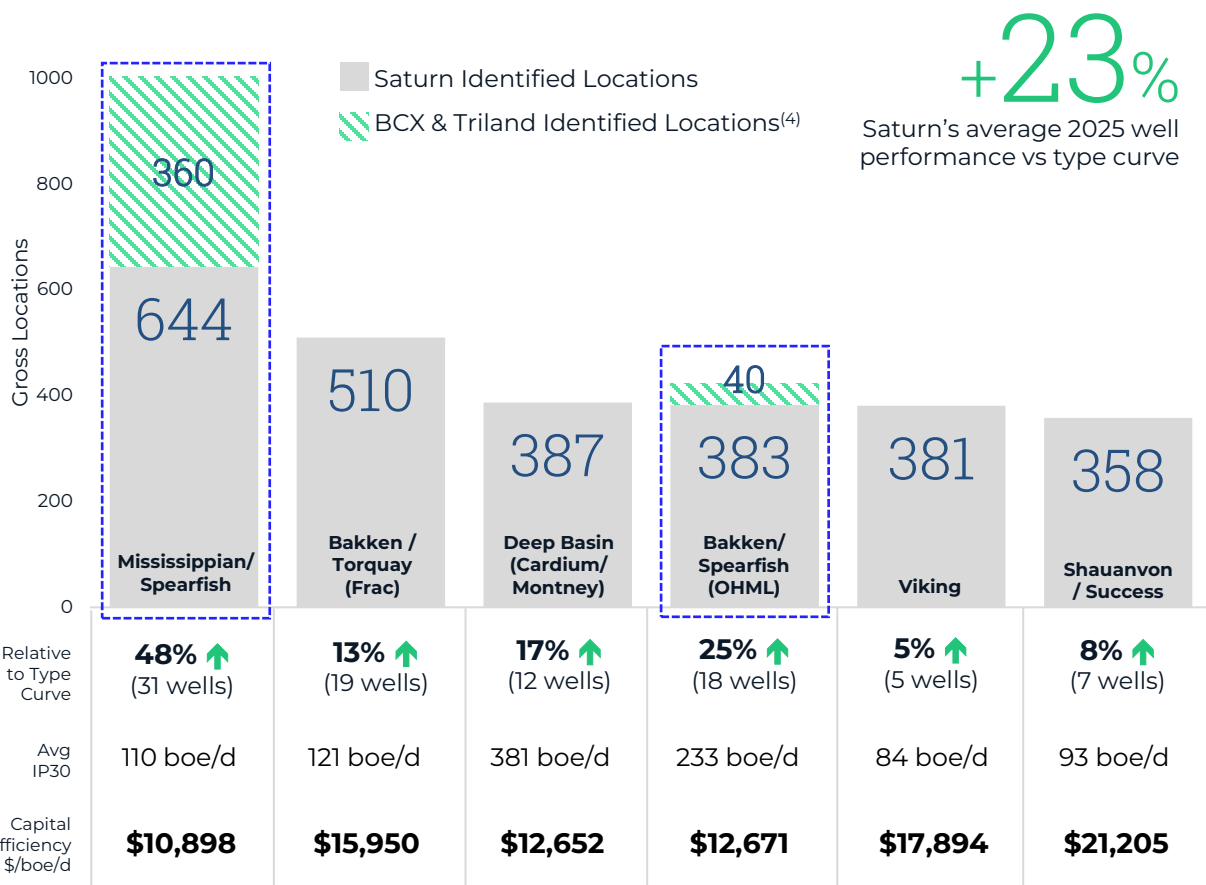
Saturn SE SK Development Advancement

Production - IP30 Performance – Top Tier Inventory

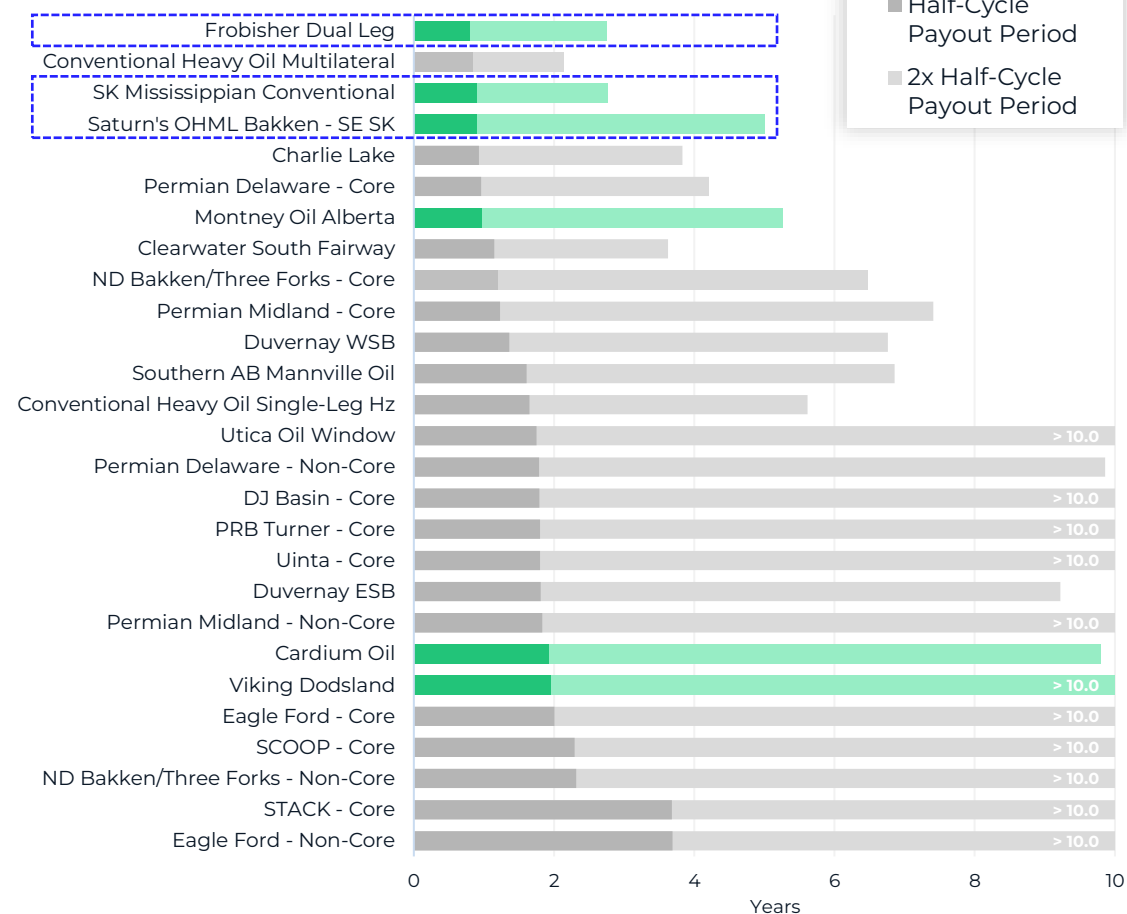


TYPE CURVE OUTPERFORMANCE DRIVES STRONG RETURNS

2025 IDENTIFIED LOCATION COUNT +
AVERAGE WELL PERFORMANCE VS TYPE CURVE ^(1,2)



PRIMARY PAYOUT PERIODS* (YEARS)



* Peters & Co. Research (Oct/25). Due to limited production duration, Bakken OHML wells are not yet included in the Peters' data set. The estimated payouts shown here are internal estimates by Saturn.

2026 Development: SE SK OHML Program

Saturn is the Leading Developer of Open Hole Multi-Lateral (OHML) Technology in Saskatchewan

37

OHML planned
locations in 2026

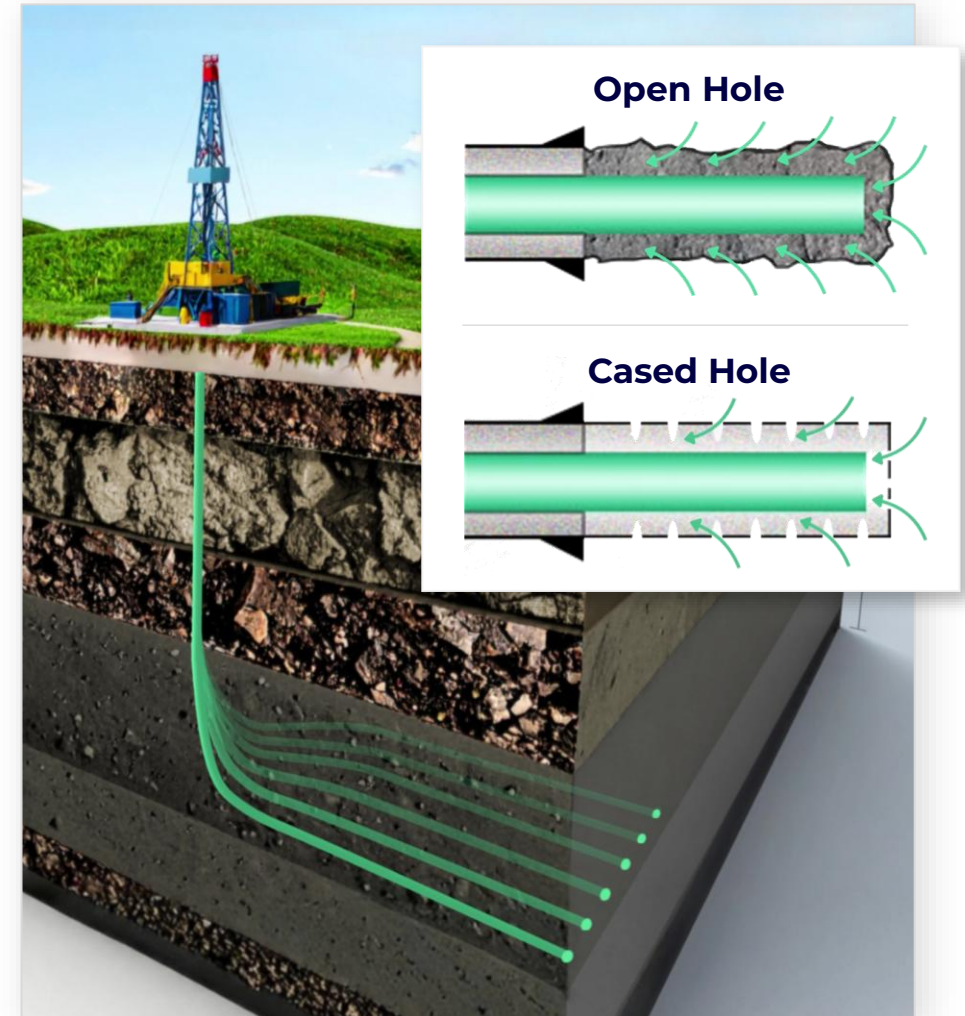
~450

OHML locations
identified in SE SK⁽¹⁾

up to 20%

of 2026 development
capital allocated to OHML

- **Saturn is a leading developer of OHML wells in SK;** the only company to deploy this drilling technique across four formations in SE SK
- **70% increase** in Saturn's OHML wells targeted in 2026 vs 2025
- **20% improvement** on our drill rates in the Bakken from 2023 to 2025
- **Open hole provides distinct advantages** vs cased hole
 - ✓ Greater reservoir exposure = more area contacted
 - ✓ Entire well bore open to inflow vs just frac ports = enhanced production rates
 - ✓ Targeted laterals avoid contact with wet zones = reduced risk
 - ✓ Lower water production = lower opex



2026 Development: SE SK Conventional Program



Conventional Development Program Provides Flexibility with Strong Returns

36

Conventional wells planned

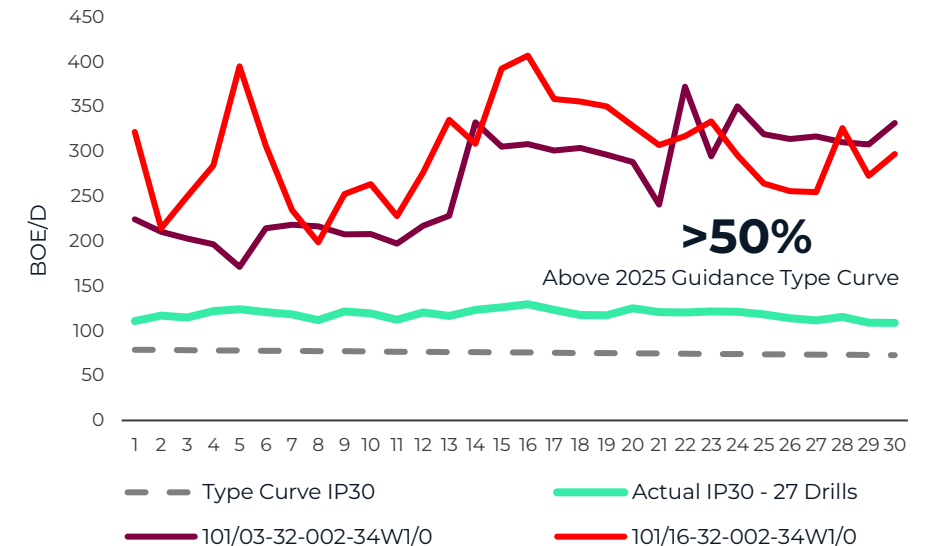
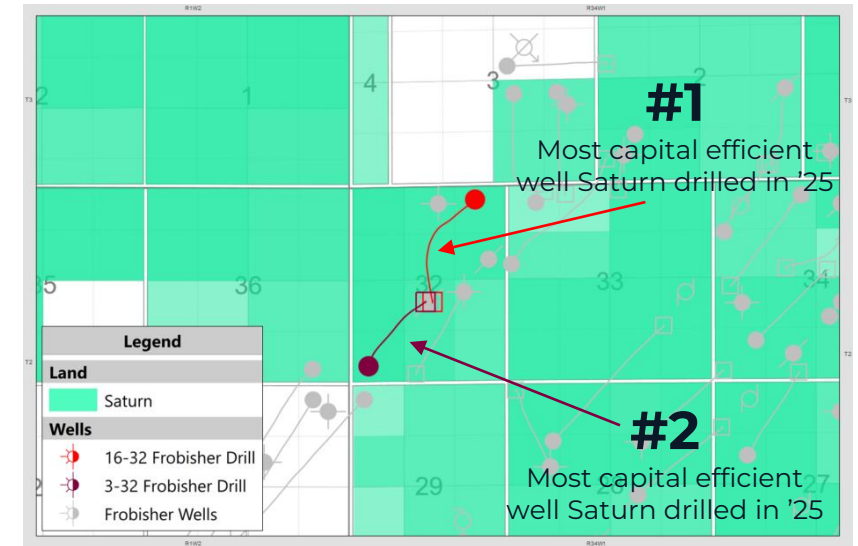
>640

Conventional locations identified in SE SK⁽¹⁾

#1 returns

Highest ranked plays in Saturn's inventory

- **Conventional Mississippian & Spearfish** wells have Saturn's lowest drilling costs with high deliverability, resulting in the most capital efficient wells
- Conventional wells enhance our drilling portfolio:
 - ✓ Represent 9 of our top 10 **most capital efficient wells** drilled in 2025
 - ✓ Robust economics even in soft commodity environment
 - ✓ Short cycle times enhance flexibility
 - ✓ Variety of zones and pools in which to find opportunities
 - ✓ Competitive advantage from leveraging our infrastructure network
 - ✓ Re-entry opportunities reduce capital and utilize existing wellbores



2026 Development: Creelman Waterflood Expansion

Progressing Secondary Recovery, Re-Pressurizing Infill Drilling and Supporting Sustainability

Initial Creelman Development

- 18.5 sections of 100% WI land adjacent to existing waterflood
- **70 MMbbls OOIP**, 5% increased waterflood recovery, plus up to 40 re-pressurized infill drills
- Converted 7 producers to injectors and 1 producer to source well in 2025
- 14 further conversions, providing pressure support for 3 infill drills in 2026, plus planned infill drills in 2027

Future Expansion

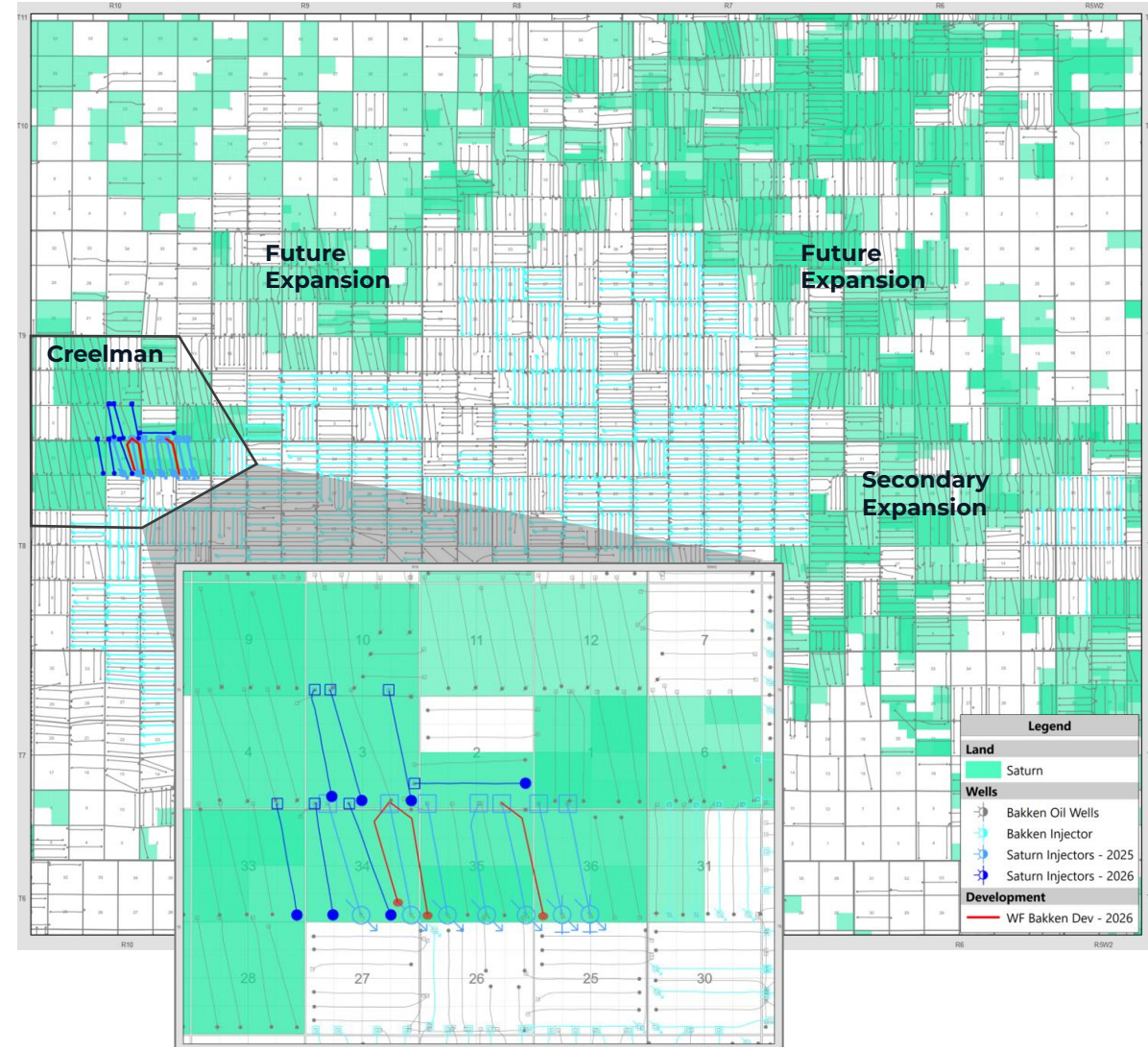
- Potential to implement identified in surrounding areas
- >100 sections of waterflood development opportunity

40

Future Creelman
re-pressurized drill locations

>300

Potential Bakken injector
conversion in expansion areas



2026 Development: AB Cardium



Innovative Longer Laterals and Multi-Pad Development Boost Economics & Capital Efficiencies

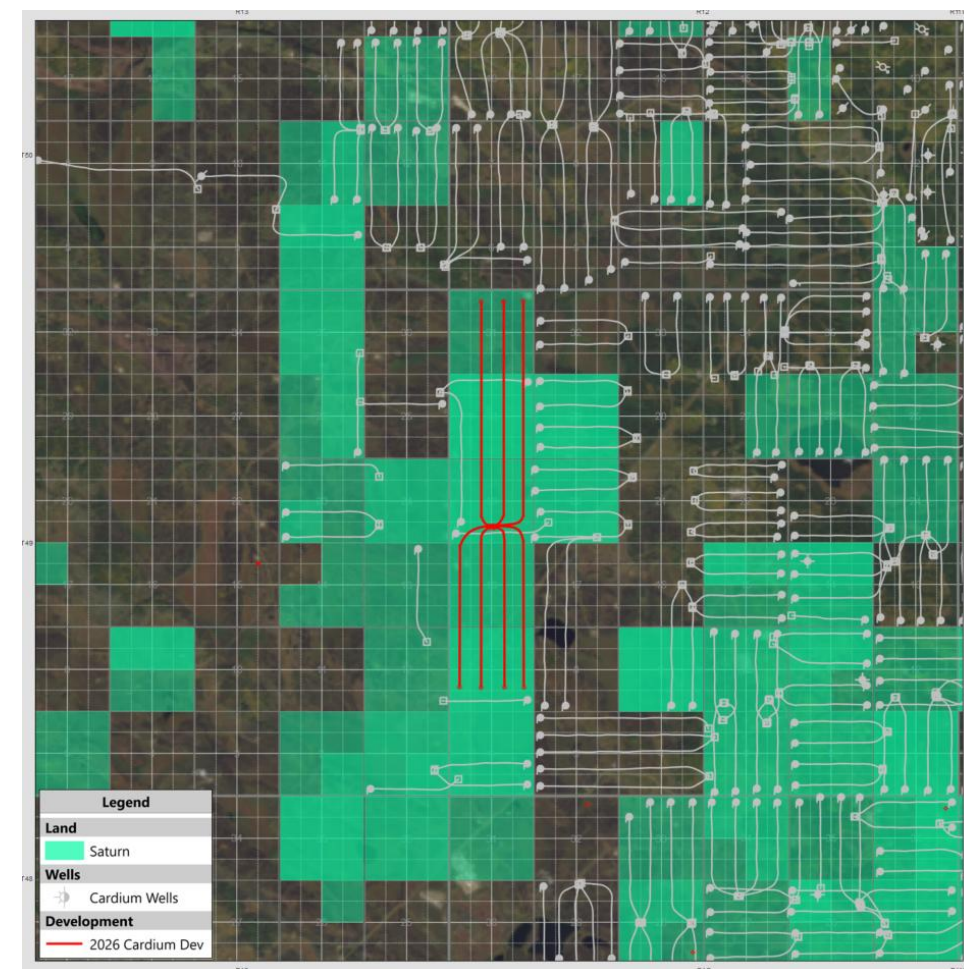
Saturn's Cardium Approach

- Enhancing the Cardium inventory value by adopting new technologies that enable extended reach horizontal (“ERHz”) wells
- Saturn drilled the fastest ERHz Cardium well** on record in Q3/25, drilling to 5,090 metres MD in a single run & achieved well completion from surface casing to total depth in **only 4.8 days**
- Saturn drilled the longest Cardium well** on record at 7.57 kms or 24,800 ft.
 - 2-mile well has 1.3x capital costs with **2x reservoir exposure**
 - 3-mile well has 1.6x capital costs with **3x reservoir exposure**
- Cardium delivers **Saturn's highest production wells**
- Increased pad size due to land concentration strategy

2025 SATURN ALBERTA DEVELOPMENT WELLS ON TOP 10 LIST⁽²⁾

UWI	Formation	Category	Month	Rank
100/05-02-026-03W5/00	Cardium	Top Cardium Monthly Vols	Apr/25	4
100/01-29-025-02W5/00	Cardium	Top Cardium Monthly Vols	May/25	4

EXTENDED REACH MULTI WELL PAD DEVELOPMENT AT WEST PEMBINA



Q2/26 Highlights: Exceeding Expectations

Positive Momentum Continues in Q2 2026 Performance



PRODUCTION EXCEEDS GUIDANCE

41,447 boe/d⁽²⁾

Average volumes exceed guidance for 8th consecutive quarter

RECORD QUARTERLY REVENUE

\$359 M

Reflects strong production volumes and supportive pricing

ROBUST ADJUSTED FUNDS FLOW⁽¹⁾

\$123 M

Ongoing strategy execution benefitted from higher oil prices

\$0.68/sh

FREE FUNDS FLOW BEAT EXPECTATIONS⁽¹⁾

\$82.5MM

Directed to debt repayment, tuck-in acquisitions & returning capital

\$0.46/sh

EXPANDING PRODUCTION PER SHARE

+66%

Growth in production per debt-adjusted share^(1,3) vs Q2/25

SYSTEMATIC DEBT REPAYMENT CONTINUES

1.3x

Net debt / Adj. EBITDA⁽¹⁾ at Q2/26

1) See disclaimer "Information Regarding Non-GAAP and Other Financial Measures"

2) See disclaimer "Supplemental Information Regarding Product Types"

3) Based on Saturn's Q2 2026 market cap and 2026 annual free funds flow

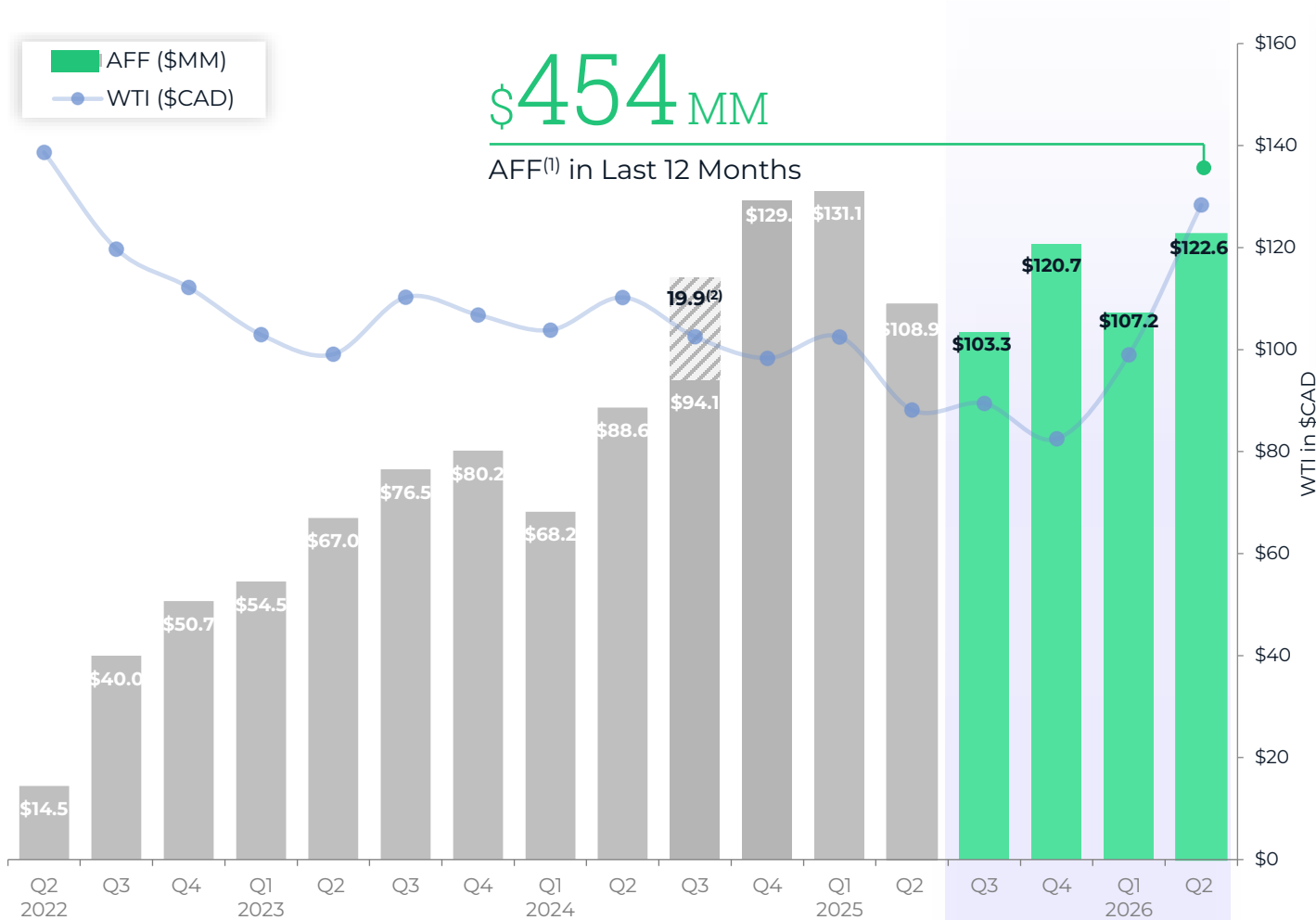
4) Q2/26 over Q2/25. Calculated by converting quarter end net debt to shares, adding that to the basic shares outstanding at quarter end and dividing the total production in boe during the quarter by the debt adjusted shares.

Fueling Free Cash Flow and Disciplined Capital Allocation



Focus on Generating Strong Free Funds Flow and Increasing Value Per Share

ADJUSTED FUNDS FLOW ("AFF")⁽¹⁾ GROWTH (\$ MILLIONS)



Capital Return Framework

- **Normal Course Issuer Bid** completed early in Jul/26 (12.1MM maximum shares; ~65,400 shares daily)
- **Substantial Issuer Bid** closed Jul 16/25 (~1.6 MM shares repurchased at \$2.15 per share)

24.2 MM

Shares repurchased via NCIB + SIB (Aug/24-Jul/26)
~12% of shares outstanding at launch of NCIB in Aug/24

~\$66 MM

Returned to Shareholders via NCIB + SIB since Aug/24
~7% of current market cap⁽³⁾

1) See disclaimer "Information Regarding Non-GAAP and Other Financial Measures"

2) Normalized AFF (before one-time \$20MM cost for early termination payment to unwind certain legacy WTI oil hedges contracted at a low price; opportunistically monetized when oil prices dropped and costs became substantially less expensive)

3) Based on market cap of ~\$1.0B; using Aug 5, 2026, shares outstanding

Refinancing Senior Notes Enhances Liquidity



Increased Financial Flexibility Supports Multiple Paths to Value Creation

STRATEGIC BENEFITS

Reduced Costs

- Lowered blended interest expense by ~2%
- Improved cash flow retention

Expanded Flexibility

- Unsecured structure
- Relaxed covenant framework
- Replaced mandatory 10% amortization payment with semi-annual offer to repurchase 2.5% of principal at 101%

Increased Tenor

- Maturity extended 2 years to 2031

New Issue: Senior Unsecured Notes Maturing 2031

US\$575_{MM} @ 8.5% + CAD\$185_{MM} @ 7.5%

Amended Credit Facility Provides Added Liquidity

\$200_{MM}
Elected commitment

\$500_{MM}
Borrowing base +
commitments

Active Hedge Strategy Protects Downside

40-60%
Oil & liquids¹⁾ hedge target

Hedge differentials, natural gas
& foreign exchange

¹⁾ Net of royalties

2026 Updated Guidance Details



Current Price Environment Supports Increased Activity with Continued Focus on Free Funds Flow

Revised 2026 Guidance (US \$80 WTI) ^{(4),(5)}	Original Guidance (US \$60 WTI)	Updated Guidance
Development Capital Expenditures (\$MM) ^{(2),(5)}	\$180 - \$190	\$355 - \$375
Annual Average Production (boe/d) ⁽¹⁾	39,000 - 41,000	43,000 - 44,000
Oil & Liquids Weighting (%)	~81%	~82%
Exit Volumes (boe/d)	N/A	48,000-50,000
Adjusted Funds Flow (AFF) ⁽²⁾ (\$MM)	\$325 - \$375	\$535 - \$570
AFF Per Share ^{(2),(3)}	\$1.75 - \$2.00	\$2.95 - \$3.15
Free Funds Flow ⁽²⁾ (\$MM)	\$120 - \$170	\$150 - \$200
Free Funds Flow Per Share ^{(2),(3)}	\$0.65 - \$0.95	\$0.80 - \$1.10
Year-end Net Debt ⁽²⁾ (\$MM)	\$645 - \$695	\$955 - \$990
Net Debt to Proforma Adj. EBITDA ⁽²⁾ (times)	1.4x - 1.7x	1.3x - 1.5x

Operating Netback ⁽²⁾ Inputs	Original Guidance (US \$60 WTI)	Updated Guidance
Royalties (%)	12.0% - 12.5%	12.0% - 12.5%
Net Operating Expense (\$/boe) ⁽²⁾	\$20.00 - \$21.00	\$20.00 - \$21.00
Transportation Expense (\$/boe)	\$1.70 - \$1.85	\$1.70 - \$1.85
General & Administrative Expense (\$/boe)	\$1.70 - \$1.85	\$1.70 - \$1.85

1) 2026 production at midpoint is anticipated to be comprised of ~65% light and medium crude oil, 8% heavy oil, 9% NGLs & 18% natural gas

2) See Disclaimer "Information Regarding Disclosure on Oil & Gas Operational Information and Non-IFRS Measures"

3) Based on 181 million weighted average basic common shares outstanding in 2026

4) In addition, ~\$15 MM to be allocated to capitalized administrative costs, ~\$19 MM to ARO & \$16 MM primarily to lease payments. Not expecting to be taxable in 2026.

5) 2026 updated pricing assumptions: WTI crude oil of US\$80.00 WTI, US\$3.50 MSW-WTI differential, US\$15.50 WCS-WTI differential, C\$2.25/GJ AECO and 0.71x CAD/USD

SECOND HALF 2026 SENSITIVITIES

Factor	Change	Approximate AFF ⁽²⁾⁽⁶⁾ Impact
WTI Oil Price USD/bbl	+/- \$5.00	+/- \$20 MM
Oil Production Bbl/d	+/- 1,000	+/- \$18 MM
Exchange Rate CAD/USD	+/- \$0.01	+/- \$8 MM
AECO Gas Price CAD/GJ	+/- \$0.50	+/- \$3 MM

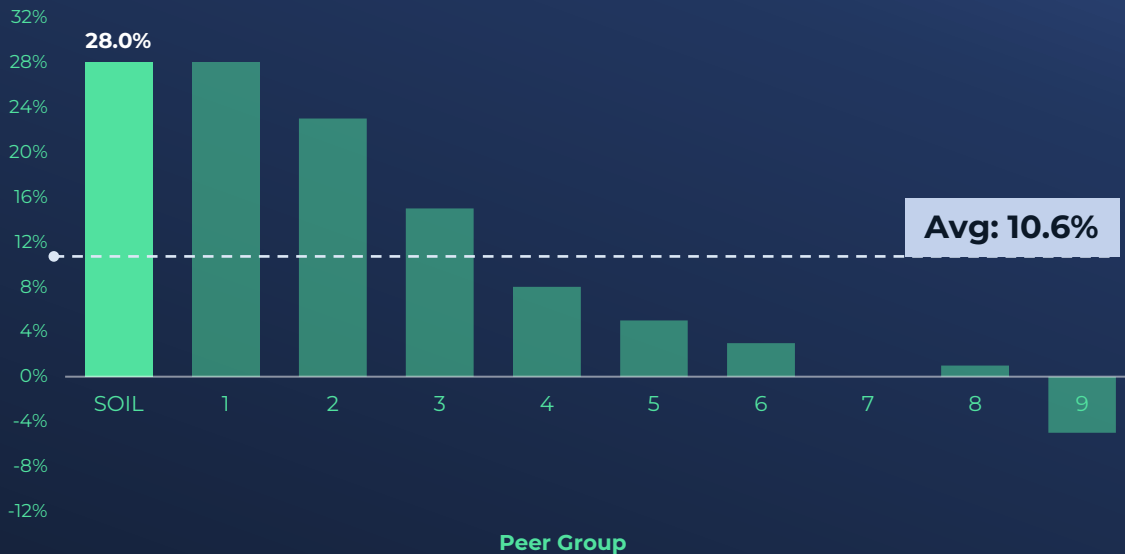
~85%
Of 2026 budget
allocated to DCET

~\$20MM
AFF⁽²⁾ impact on 2H/26 for
every \$5/bbl WTI change

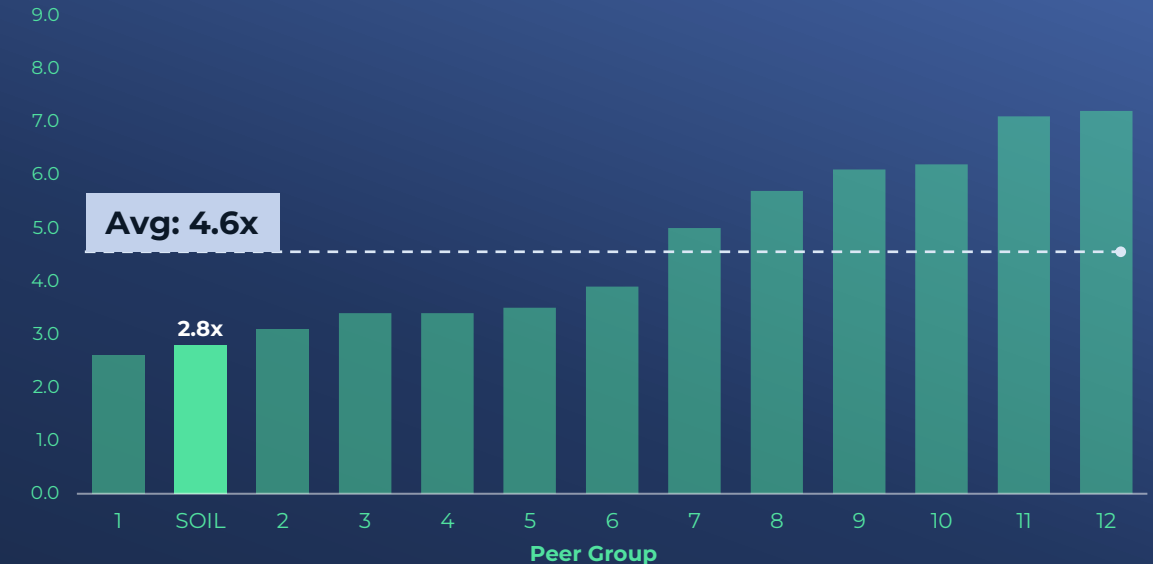
Peer Comparison & Research Coverage

Saturn Positioned for Strong Free Cash Flow to Support Debt Repayment and Return of Capital

2027E FREE CASH FLOW YIELD^(1,3)



2027E ENTERPRISE VALUE / DEBT ADJUSTED CASH FLOW (EV/DACF)^(2,3)



Firm	Analyst	Rating Most Recent Report	Target Price
ATB Cormark Capital Markets	Amir Arif, CFA aarif@atb.com	Outperform	\$8.50
Canaccord Genuity Inc.	Mike Mueller mmueller@cgf.com	Buy	\$7.50
National Bank of Canada Financial Markets	Dan Payne, CFA dan.payne@nbc.ca	Sector Perform	\$8.00
Peters & Co. Limited	Christian Comeau ccomeau@petersco.com	Sector Perform	\$8.00
Roth Canada	Jamie Somerville jsomerville@rothcanada.ca	Buy	\$10.00
Velocity Trade Capital, Canada	Mark Heim, CFA mark.heim@velocitytradecapital.com	Outperform	\$7.50
Ventum Capital Markets	Adam Gill, CFA adam.gill@ventumfinancial.com	Buy	\$9.00

1) Comparative Canadian company FCF Yields are sourced from ROTH Canada research dated July 13, 2026, and are based on ROTH's Canadian energy coverage comparables. Peers shown in the chart include IPO, SGY, GTE, SCR, KEL, TOU, SDE, LGN, POU.

2) Comparative Canadian company valuations of EV/DACF (unhedged) are sourced from Peters & Co. research dated July 27, 2026. EV equals the sum of equity market capitalization plus Net Debt; DACF is Debt Adjusted Cash Flow meaning 2026E cash flow on forward strip adjusted for financing expenses and unhedged. Peers shown in the chart include BNE, SGY, OBE, BTE, JOY, LGN, WCP, SCR, TVE, HWX, ATH & IPCO.

3) See disclaimer "Information Regarding Non-GAAP and Other Financial Measures"

The Saturn Investment Opportunity (TSX: SOIL)



High-Quality Light Oil Weighted Assets, Free Funds Flow Generation and Per Share NAV Disconnect

01.

Diversified Asset Base

- >80% weighted to high-value light oil & liquids
- Consistent type curve outperformance (23% in 2025 / 22% in 2024)⁽³⁾
- Record 2025 production, adjusted funds flow & free funds flow⁽¹⁾

02.

Downside Protection

- Discounted valuation + 50% free funds flow yield^(1,2) at year-end '25
- Risk management protects the downside
- Flexible capital program allows rapid shifting in response to commodity prices

03.

Compelling Upside

- Potential for rerate with consistent performance & deleveraging
- Per share metrics significantly improved with NCIB & SIB
- Disconnect between market value and ~\$11/sh (1P) net asset value^(1,4) creates opportunity

1) See disclaimer "Information Regarding Non-GAAP and Other Financial Measures"

2) Based on Saturn's year end 2025 market cap and 2025 annual free funds flow

3) See disclaimer "Oil and Gas Advisories"

4) Based on 3CA pricing as at April 1, 2026

Head Office

Saturn Oil & Gas Inc.

Suite 2500, 600 – 3rd Ave SW
Calgary, AB T2P 0G5

info@saturnoil.com
403.268.7800



Appendix



Saturn's Community Involvement



Driving Positive Change Through Diversified Partnerships, Donations, and Volunteering

Fostering Healthy and Vibrant Communities

Saturn is committed to driving positive change through strategic partnerships and targeted donations. Our approach emphasizes building meaningful relationships, supporting local economies, and enhancing community well-being. By diversifying our sponsorships and volunteer initiatives, we aim to deliver lasting benefits across multiple focus areas in the communities where we operate.

Key Priorities

- **Children's Health:** Hospitals and health foundations centered around supporting children and their families as they navigate illness
- **Cancer:** Organizations targeting research, treatment and preventative measures for cancer and cancer-related issues
- **Mental Health:** Supporting organizations that raise awareness, reduce stigmas, and fund initiatives to improve mental health and wellbeing
- **Food Security:** Contributing to local food banks to help address hunger

Some of Our Previous and Ongoing Support has Included:



Canadian
Cancer
Society

Rural & Local
FOOD BANKS



Kinder Kollege

\$250,000

2026 budget
for sponsorships and
charitable contributions

Saturn's OHML Development Program



Open Hole Multi-Lateral (OHML) Development is Cornerstone of Saturn's SE Saskatchewan Program

Drilling

- Bakken/Torquay historically fracked; uneconomic in thinner reservoirs as stimulation not maintained within formation – water from offsetting formations can migrate
- 1st and only operator** in Canada to drill an OHML Spearfish well (3 drilled to date) – 3rd OHML Spearfish well (16-05) came on at 330 boe/d⁽¹⁾, **~3x type curve expectations**⁽²⁾
- Two Midale OHML re-entries in Q4/25 have up to 6 legs each, and Saturn drilled the first of two Torquay OHML wells in 2026; early results exceeding expectations

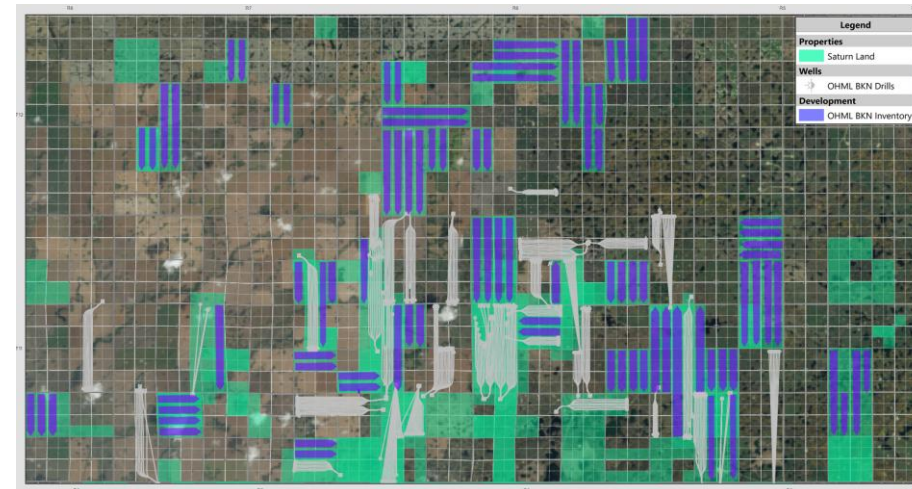
Results

- OHML inventory⁽³⁾ represents 15% of our ~2,600 total identified locations, and has essentially doubled every year for the last three years as we progress to other plays
- OHML comprises some of the more prolific wells recently drilled in SK (11-21-11-6W2, 15-21-11-6W2, and 16-21-11-6W2)
- Industry-wide Bakken OHML production has grown from 0 to >2,500 boe/d in less than three years; ~35 wells have been drilled

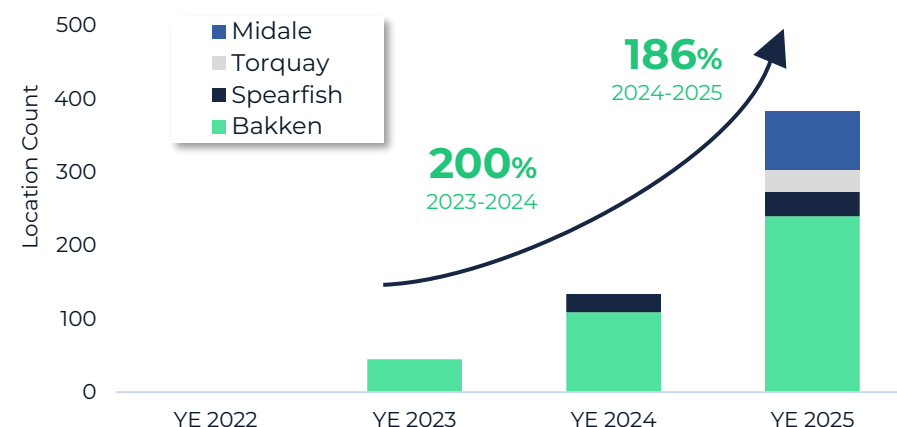
2025 SATURN SK OHML DEVELOPMENT WELLS ON TOP 10 LIST⁽⁴⁾

UWI	Formation	Category	Month	Rank
101/16-21-011-06W2/00	Bakken	Top 'Oil' Monthly Vols	Sept/25	7
101/16-21-011-06W2/00	Bakken	Top 'Oil' IP Rates	Sept/25	7
101/15-21-011-06W2/00	Bakken	Top 'Oil' Monthly Vols	May/25	3
101/15-21-011-06W2/00	Bakken	Top 'Oil' IP Rates	May/25	4
101/11-21-011-06W2/00	Bakken	Top 'Oil' IP Rates	Jul/24	2

SATURN'S SE SK OHML DRILLS & LOCATION INVENTORY⁽³⁾



OHML INVENTORY⁽³⁾ GROWTH OVER TIME



Alberta Operations – Montney & Cardium



Longer Laterals and Innovative Completions Boosting Economics & Capital Efficiencies

Cardium

- Saturn drilled the fastest extended reach Hz Cardium well on record in Q3/25, drilling to 5,090 metres MD in a single run - achieved well completion from surface casing to total depth in **only 4.8 days**

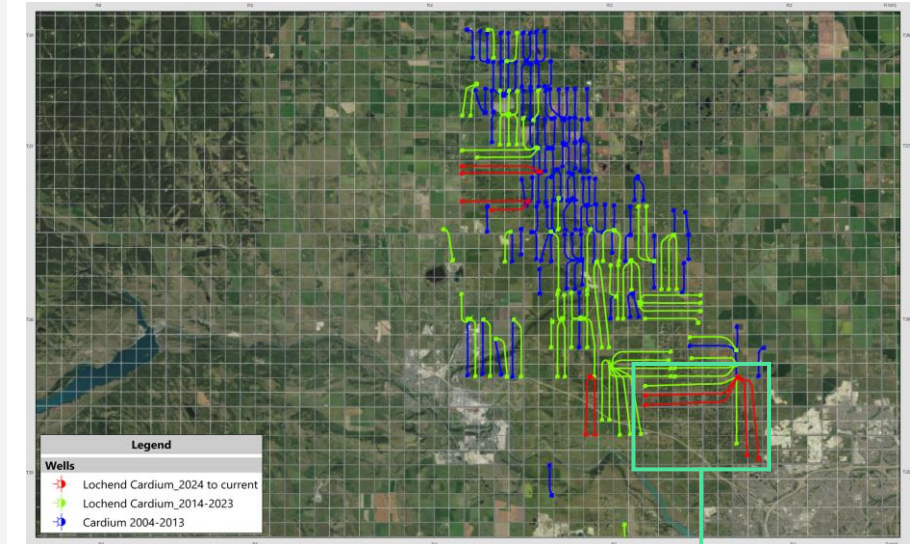
Kaybob Montney

- Finalized drilling and completion of Kaybob Montney 3-well pad, featuring 3-mile extended reach laterals - the longest laterals on record to be drilled in Kaybob
- North well on the pad has the most productive days and is already exceeding type curve expectations
- South 2 wells still cleaning up, but based on reservoir quality observed while drilling, a consistent result to the north well is expected once peak production reached

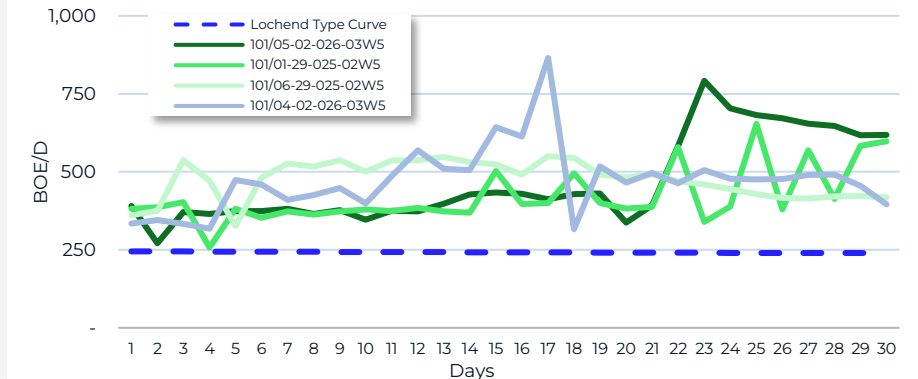
2025 SATURN ALBERTA DEVELOPMENT WELLS ON TOP 10 LIST⁽²⁾

UWI	Formation	Category	Month	Rank
100/05-02-026-03W5/00	Cardium	Top Cardium Monthly Vols	Apr/25	4
100/01-29-025-02W5/00	Cardium	Top Cardium Monthly Vols	May/25	4

EVOLUTION OF THE CARDIUM SINCE 2004



TYPE CURVE⁽¹⁾ OUTPERFORMANCE – 4 LOCHEND WELLS IP30



Saturn's Operations



Portfolio of Low-Decline, High-Return Plays Targets Multiple Stacked Oil Zones

- Focus on mid-life cycle assets with high oil weighting
- Similar full and half cycle costs since infrastructure already built out
- Assets feature low decline, lower cost, repeatable wells which mitigates risk
- Optimize assets, deploy technology, leverage knowledge and learnings across our portfolio to unlock value

~2.6 K

Identified
Drilling Locations⁽²⁾

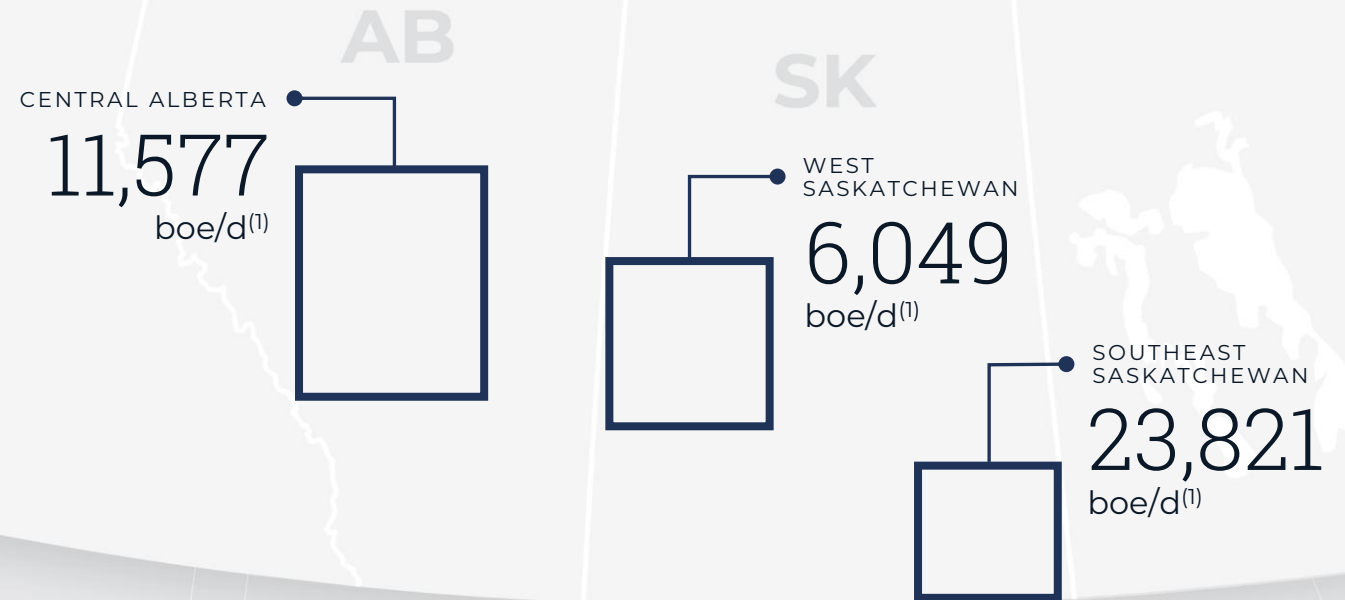
~20 Yrs

Development
Inventory

~22 %

Decline
Rate

Three diversified, light oil, core operating areas across 1.5 MM acres of land, generating 41,447 boe/d⁽¹⁾ in Q2 2026



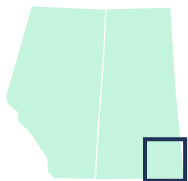
1) See disclaimer "Supplemental Information Regarding Product Types"
2) See disclaimer "Identified Inventory"

Southeast Saskatchewan



Anchor Area with High Rate of Return, Abundant Seismic Coverage, Large Scale Owned Infrastructure

Overview



- Flat Lake
- Viewfield
- Oxbow

Q2/26 Production

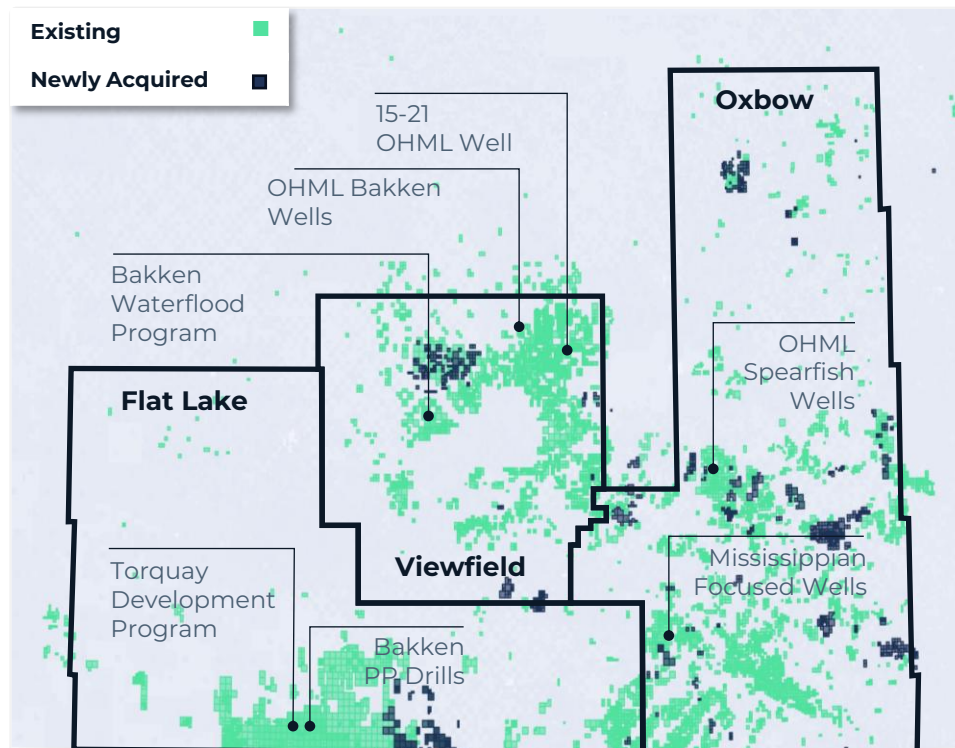
23,821

Boe/d

57%

Of Total Volumes

Area Map



Play Development:

- **Viewfield:** Bakken (OHML & Frac)
- **Oxbow:** Frobisher, Midale, Spearfish, Torquay (OHML & conventional)
- **Flat Lake:** Torquay / Bakken (Frac), Oungre (conventional)

2026 Capital Development Focus:

100 (87.2 net) wells planned in SE Sask; ~20% of 2026 capital directed to OHML drills

- 37 (28.2 net) Bakken/Spearfish/Midale/Torquay OHML well locations targeted
- OHML Play Expansion – Drilled Saturn's first Midale and Torquay OHML wells; plan to drill first P2 Spearfish & Lower Shaunavon OHML wells in 2026

Conventional Mississippian and Spearfish delineation

- ~36 gross wells planned in 2026 – highly capital efficient

Expanding Bakken waterflood at Creelman

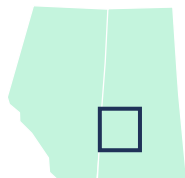
- ~5% of total 2026 capital earmarked for waterflood
- 14 conversions to injectors in 2026, providing pressure support for 3 infill drills in 2026 + planned infill drills in 2027

West Saskatchewan



Resource Plays, Repeatability, Steady Production and Cash Flow

Overview



- Kindersley
- Herschel
- Plato
- Battrum

Q2/26 Production

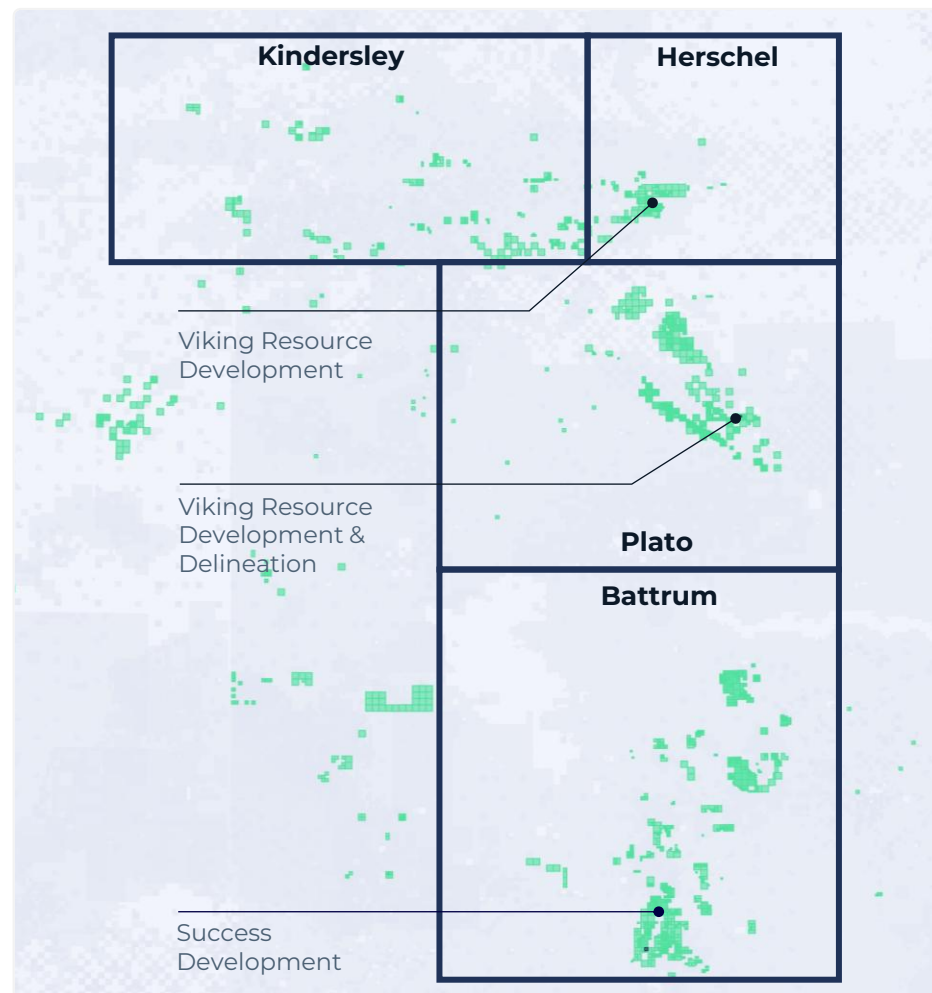
6,049

Boe/d

15%

Of Total Volumes

Area Map



Play Development:

- **Kindersley, Herschel and Plato:** Viking
- **Battrum:** Success / Lower Shaunavon
- **Waterflood** in Cantuar / Battrum Units

2026 Capital Development Focus:

~18% of 2026 capital allocated to this area (\$57MM)

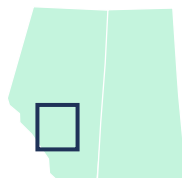
- Capital acceleration from H2/26 into Q2/26 enabled a rig to be added in this area
- Anticipate drilling 37 (32.0 net) wells in this area in 2026
- Viking & Success plays offer inventory of short cycle-time locations - drilling can restart rapidly and volumes can be brought on within weeks

Central Alberta



Resource Play, Large Prospect Inventory, Significant Expansion Potential

Overview



- Kaybob
- West + East Pembina
- Brazeau
- Lochend

Q2/26 Production

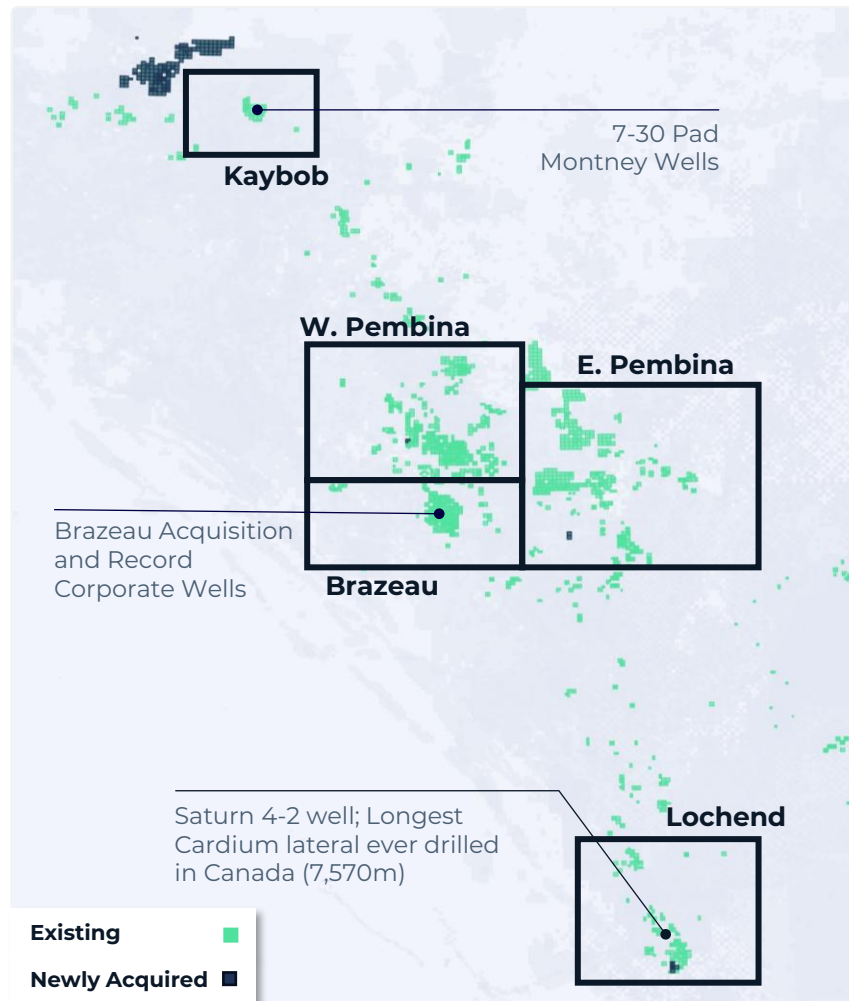
11,577

Boe/d

28%

Of Total Volumes

Area Map



Play Development:

- **E/W Pembina, Brazeau:** Cardium
- **Kaybob:** Montney

2026 Capital Development Focus:

Enhancing the Cardium inventory value

- ~24% of 2026 capital allocated to continued Cardium development at Lochend and West Pembina
- Drilling seven-well pad featuring extended reach horizontals up to 3-miles – longest ever drilled in the West Pembina area
- Production optimization in Kaybob continues to occur with gas lift to pump jack conversions
- Potential to drill Brazeau Cardium wells

Management



A Long History of Value Creation in the Oil & Gas Production Space



John Jeffrey

Chief Executive Officer

Former CFO and founding partner of Axiom Group, which drilled >1,000 wells for oil & gas clients in Western Canada

Has led Saturn to successfully grow from ~400 boe/d to ~43,000 boe/d in just over four years

Currently serves on the board of EPAC

MBA (Finance) from University of Saskatchewan, and B. Comm (Economics)



Justin Kaufmann

Chief Development Officer

Former Manager of Axiom Group, which drilled >1,000 wells for oil & gas clients in Western Canada

Previously held senior management and geology roles for various private and public companies, and consulted for Lightstream Resources and Novus Energy

P. Geo (APEGGS), and B.Sc. (Geology) from University of Saskatchewan



Scott Sanborn

Chief Financial Officer

Former Corporate Controller of Jupiter Resources Ltd. - sold for \$626 million in 2020

Previously held various leadership roles with energy companies including Marquee Energy and Verano Energy, and earlier, worked with KPMG LLP

CPA designation, and B. Comm (Accounting) from the University of Calgary



Grant MacKenzie

Chief Legal Officer

Former Partner at Dentons Canada LLP

Over 20 years experience in law dealing with public issuers with respect to capital markets, M&A, public offerings and stock exchange compliance

Bachelor of Laws (LL.B.) from the University of New Brunswick

Management



A Long History of Value Creation in the Oil & Gas Production Space



Jamie Kuntz

Senior VP Operations

Former Facility & Pipeline Engineering Manager at Ridgeback Resources

Over 20 years experience in production, facilities and pipelines, and asset management

Southern Alberta Institute of Technology with a vocation in Energy & Natural Resources and Chemical Process Operations



Tyler Cheetham

VP Land

Former Senior Landman roles at Crescent Point Energy and Husky Energy

Over 20 years experience with A&D, land strategy, and leading successful land opportunities and advancements

B. Comm from University of Lethbridge and a member of the Canadian Association of Land and Energy Professionals (CALEP)



Joel Robertson

VP Finance

Over 10 years of oil and gas focused accounting experience

Previously held roles of increasing responsibility at PFB Corporation and Jupiter Resources Ltd., and prior thereto, serviced clients at KPMG LLP

CPA designation, Bachelor of Business Administration (Finance) from Trinity Western University



Cindy Gray

VP Investor Relations

Former CEO and Founder of 5 Quarters Investor Relations

Over 20 years experience in financial communications, including senior and executive roles at several public companies, and leading global business development for one of the TSX & TSX-V practice groups

MBA from University of Calgary, and BA (Sociology/ Psychology)



Sound Governance and Strategic Oversight

John Jeffrey, MBA, BA

- Former CFO and founding partner of Axiom Group
- Led Saturn to successfully grow from ~400 boe/d to >43,000 boe/d in just over four years
- MBA majoring in Finance from University of Saskatchewan, and B. Comm (Economics)

Ivan Bergerman, J.D.

- Founded Bergerman Smith LLP in 2010
- Extensive experience in public company advisory, IPOs, exempt market distributions, corporate governance, M&A, corporate structuring & restructuring, financing, natural resources, intellectual property and general corporate and commercial
- Graduate of University of Saskatchewan, College of Law

Andrew Claugus, PE

- Entrepreneur and independent businessman with extensive experience in petroleum engineering
- Engineering Manager for MECO IV, LLC until the company was sold, after which Mr. Claugus founded Cerrito Energy, a privately backed oil and gas company investing in non-operated interest in core areas of established basins.
- Master of Engineering in Petroleum Engineering from the Colorado School of Mines, along with a BSc in Chemical Engineering from Case Western Reserve University

Dr. Thomas Gutschlag

- Chairman, Cofounder and former CEO/CFO of Deutsche Rohstoff AG, a public company listed on the Frankfurt Stock Exchange with a focus on oil and gas development in the United States
- Dr. Gutschlag is a qualified economist with a degree in economics from the University of Heidelberg and a doctorate from the University of Mannheim

Jim Payne

- CEO of dynaCERT Inc., and CEO of a privately-held consulting, project management and real estate development company operating in the Greater Toronto Area
- Over 38 years of experience in strategic leadership roles within both public and private companies, corporate governance, finance and accounting, capital markets, executive leadership and business performance improvements
- Graduated St. Clair College in Construction Engineering, Project Management and Estimating

Lynn A. Peterson

- Former Executive Chair of Chord Energy Corp. (NYSE: CHRD) and previously, served as CEO of Whiting Petroleum Corporation; CEO/Chair of SRC Energy; and was co-founder/Chair/CEO of Kodiak Oil & Gas
- 40 years of energy industry experience and extensive senior leadership, governance and operational expertise, particularly in the Williston Basin
- Graduated from University of Northern Colorado with a B. Sc. in Accounting

Chris Ryan

- President & CEO for Broadbill Energy Inc.; previously Director of Midstream for Tundra Energy Marketing Ltd.
- Authored 25 scientific publications; numerous as Research Scientist at the Canadian Light Source Inc.
- Board member of Canadian Crude Quality Technical Association; Co-Chair of the Sampling and Frequency Working Group for the Crude Oil Quality Association; and Honorary founding member of the Global Institute of Water Security

S. Janet Yang, MBA, BA

- CFO for Reveam, Inc.; previously Research Director, Energy and Mining at GMT Capital Corp.
- Former Executive Vice President & CFO of W&T Offshore, Inc. from 2018-2023
- BA Economic from Rice University and MBA from the Booth School of Business at the University of Chicago

Q2 / 1H 2026 Overview



Production Beat for 8th Consecutive Quarter Drove Record Revenue

	Three Months Ended			Six Months Ended	
(\$000s, except per share amounts)	June 30, 2026	March 31, 2026	June 30, 2025	June 30, 2026	June 30, 2025
FINANCIAL HIGHLIGHTS					
Petroleum and natural gas sales	358,714	270,237	236,712	628,951	514,793
Cash flow from operating activities	126,955	113,246	89,865	240,201	255,237
Operating netback, net of derivatives ⁽¹⁾	147,272	132,740	131,833	280,012	289,400
Adjusted EBITDA ⁽¹⁾	142,055	126,528	131,712	268,583	284,897
Adjusted funds flow ⁽¹⁾	122,609	107,228	108,854	229,837	239,975
per share - Basic ⁽¹⁾	0.68	0.59	0.56	1.27	1.22
- Diluted ⁽¹⁾	0.64	0.59	0.53	1.20	1.16
Free funds flow ⁽¹⁾	82,528	62,478	93,012	145,006	150,838
per share - Basic ⁽¹⁾	0.46	0.34	0.48	0.80	0.77
- Diluted ⁽¹⁾	0.43	0.34	0.45	0.76	0.73
Net income (loss)	108,116	(97,324)	95,054	10,792	132,873
per share - Basic	0.60	(0.53)	0.49	0.06	0.67
- Diluted	0.57	(0.53)	0.46	0.06	0.64
Acquisitions, net of cash acquired	45,665	(1,713)	5,132	43,952	5,132
Proceeds from dispositions	-	(3,503)	-	(3,503)	-
Capital expenditures ⁽¹⁾⁽³⁾	40,081	44,750	15,842	84,831	89,137
Total assets	2,192,572	2,174,597	2,103,571	2,192,572	2,103,571
Net debt ⁽¹⁾ , end of period	761,553	724,763	694,835	761,553	694,835
Shareholders' equity	909,286	845,780	929,573	909,286	929,573
Common shares outstanding, end of period	178,300	179,987	194,809	178,300	194,809
Weighted average, basic	179,788	181,989	195,644	180,883	196,872
Weighted average, diluted	191,025	181,989	206,040	191,744	207,268

OPERATING HIGHLIGHTS

Average production volumes

Light and medium crude oil (bbls/d)

Heavy crude oil (bbls/d)

NGLs (bbls/d)

Natural gas (mcf/d)

Total boe/d

% Oil and NGLs

Average realized prices

Crude oil (\$/bbl)

NGLs (\$/bbl)

Natural gas (\$/mcf)

Processing expenses (\$/boe)

Petroleum and natural gas sales (\$/boe)

Operating netback (\$/boe)

Petroleum and natural gas sales

Royalties

Net operating expenses⁽¹⁾

Transportation expenses

Operating netback⁽¹⁾

Realized loss on derivatives

Operating netback, net of derivatives⁽¹⁾

	Three Months Ended			Six Months Ended	
	June 30, 2026	March 31, 2026	June 30, 2025	June 30, 2026	June 30, 2025
Light and medium crude oil (bbls/d)	26,614	27,645	26,712	27,130	27,202
Heavy crude oil (bbls/d)	3,244	3,199	3,438	3,218	3,441
NGLs (bbls/d)	3,858	3,938	3,310	3,898	3,314
Natural gas (mcf/d)	46,385	50,004	41,740	48,185	42,526
Total boe/d	41,447	43,116	40,417	42,277	41,045
% Oil and NGLs	81%	81%	83%	81%	83%
Crude oil (\$/bbl)	122.14	88.94	79.72	105.36	85.15
NGLs (\$/bbl)	58.35	43.08	40.24	50.68	46.57
Natural gas (\$/mcf)	1.81	2.19	1.80	2.01	2.14
Processing expenses (\$/boe)	(0.34)	(0.46)	(0.26)	(0.40)	(0.26)
Petroleum and natural gas sales (\$/boe)	95.11	69.64	64.36	82.19	69.29
Petroleum and natural gas sales	95.11	69.64	64.36	82.19	69.29
Royalties	(12.25)	(7.76)	(7.68)	(9.97)	(8.36)
Net operating expenses ⁽¹⁾	(20.98)	(20.49)	(18.28)	(20.73)	(18.93)
Transportation expenses	(1.75)	(1.73)	(1.65)	(1.74)	(1.60)
Operating netback ⁽¹⁾	60.13	39.66	36.75	49.75	40.40
Realized loss on derivatives	(21.09)	(5.45)	(0.91)	(13.16)	(1.44)
Operating netback, net of derivatives ⁽¹⁾	39.04	34.21	35.84	36.59	38.96

Disclaimer

Oil & Gas Advisories



Information Regarding Non-GAAP and Other Financial Measures

Throughout this presentation and in other materials disclosed by the Company, Saturn employs certain measures to analyze financial performance, financial position, and cash flow. These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from operating activities, and cash flow used in investing activities, as indicators of Saturn's performance.

The disclosure under the section "Non-GAAP and Other Financial Measures" in our MD&A, including non-GAAP financial measures and ratios, capital management measures and supplementary financial measures in the Company's Financial Statements and MD&A are incorporated by reference into this presentation.

This presentation may use the terms "Adjusted EBITDA", "Adjusted Funds Flow", "Net Debt", "Free Funds Flow", "Net Debt to Annualized Adjusted EBITDA" and "Net Debt to Annualized AFF" which are capital management financial measures. See the disclosure under "Capital Management" in our Financial Statements and MD&A for the three and six months ended June 30, 2026, for an explanation and composition of these measures and how these measures provide useful information to an investor, and the additional purposes, if any, for which management uses these measures, and, where applicable, a reconciliation of the Company's historical non-GAAP financial measures to the most directly comparable measure calculated in accordance with IFRS for the applicable period then ended.

Capital Expenditures

The Company uses capital expenditures to monitor its capital investments relative to those budgeted by the Company on an annual basis. Saturn's capital budget excludes acquisition and disposition activities as well as the accounting impact of any accrual changes or payments under certain lease arrangements. Capital expenditures in this presentation are calculated as expenditures on exploration and evaluation assets, property plant and equipment and excludes the impact of capitalized administrative costs.

Adjusted EBITDA

The Company considers Adjusted EBITDA to be a key capital management measure as it was used within certain financial covenants prescribed under the Company's previous Senior Term Loan and demonstrates Saturn's standalone profitability, operating and financial performance in terms of cash flow generation, adjusting for interest related to its capital structure. Adjusted EBITDA is defined by the Company as earnings before interest, taxes, depreciation, amortization and other non-cash or extraordinary items. Adjusted EBITDA is presented both before and after derivatives to identify the impact of WTI commodity contracts hedges in place.

Adjusted Funds Flow per Share

Adjusted funds flow per share is a non-GAAP ratio by management to better analyze the Company's performance against prior periods on a more comparable basis. Adjusted funds flow per share is calculated as adjusted funds flow from operations divided by weighted average shares outstanding during the applicable period on a basic or diluted basis.

Free Funds Flow, Free Funds Flow per Share and Free Funds Flow Yield

The Company uses free funds flow as an indicator of the efficiency and liquidity of its business, measuring its funds after capital investment available to manage debt levels, pursue acquisitions and gauge optionality to pay dividends and/or and return capital to shareholders through activities such as share repurchases. Free funds flow is calculated as adjusted funds flow in the period less capital expenditures. By removing the impact of current period capital expenditures from adjusted funds flow, management monitors its free funds flow to inform its capital allocation decisions. Free funds flow is also presented on a per share basis as a non-GAAP financial ratio. Free funds flow yield is calculated by dividing free funds flow by Saturn's market capitalization as at year end 2025 (\$447.4 million), expressed as a percentage, which is used as a valuation and capital allocation metric.

The following table reconciles adjusted funds flow to free funds flow.

(\$000s)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Adjusted funds flow	107,228	120,697	131,121
Capital expenditures	(44,750)	(64,764)	(73,295)
Free funds flow	62,478	55,933	57,826

Royalties as a Percentage of Gross Petroleum and Natural Gas Sales

Royalties as a percentage of gross petroleum and natural gas sales is calculated as royalties divided by gross petroleum and natural gas sales. This metric is used by management to quantify the Company's royalty costs as they relate to revenue before deducting certain processing expenses and to better analyze how royalty rates change over time and compare to prior periods.

Disclaimer

Oil & Gas Advisories



Capital Management Measures

National Instrument 52-112 *Non-GAAP and Other Financial Measures Disclosure* ("NI 52-112") defines a capital management measure as a financial measure that: (i) is intended to enable an individual to evaluate an entity's objectives, policies and processes for managing the entity's capital; (ii) is not a component of a line item disclosed in the primary financial statements of the entity; (iii) is disclosed in the notes to the financial statements of the entity; and (iv) is not disclosed in the primary financial statements of the entity. Please refer to note 16 "Capital Management" in Saturn's financial statements as at and for the period ended June 30, 2026, for additional disclosure on: adjusted working capital deficit (surplus), net debt, adjusted EBITDA, adjusted funds flow, free funds flow, annualized quarterly adjusted funds flow, and net debt to annualized quarterly adjusted funds flow, each of which are capital management measures used by the Company in the MD&A for the quarter ended June 30, 2026.

Supplementary Financial Measures

NI 52-112 defines a supplementary financial measure as a financial measure that: (i) is, or is intended to be, disclosed on a periodic basis to depict the historical or expected future financial performance, financial position or cash flow of an entity; (ii) is not disclosed in the financial statements of the entity; (iii) is not a non-GAAP financial measure; and (iv) is not a non-GAAP ratio. The supplementary financial measures used in this MD&A are either a per unit disclosure of a corresponding GAAP measure, or a component of a corresponding GAAP measure, presented in the financial statements. Supplementary financial measures that are

disclosed on a per unit basis are calculated by dividing the aggregate GAAP measure (or component thereof) by the applicable unit for the period. Supplementary financial measures that are disclosed on a component basis of a corresponding GAAP measure are a granular representation of a financial statement line item and are determined in accordance with GAAP.

Enterprise Value

The Company's enterprise value is calculated as total market capitalization plus net debt. Enterprise value is used to assess the valuation of the Company. Refer to the Liquidity and Capital Resources section in the MD&A for the quarter ended June 30, 2026 for further information.

Net Debt

Net debt is a key capital management measure as it is used to assess the ongoing liquidity of the Company. Net Debt is calculated as the carrying value of the Senior Notes, less adjusted working capital including cash. The Company closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company.

Net Debt to Adjusted EBITDA

Management considers Net Debt to Adjusted EBITDA an important measure as it is a key metric to identify the Company's ability to fund financing expenses, net debt reductions and other obligations. When this measure is presented quarterly, Adjusted EBITDA is annualized by multiplying by four. When this measure is presented on a trailing twelve-month basis, Adjusted EBITDA for the twelve months preceding the net debt date is used in the

calculation. Net Debt to Adjusted EBITDA is calculated as Net Debt divided by annualized Adjusted EBITDA.

Net Operating Expenses and Net Operating Expenses per BOE

Net operating expense is calculated by deducting processing income primarily generated by processing third party production at processing facilities where the Company has an ownership interest, from operating expenses presented on the Statement of income (loss). Where the Company has excess capacity at one of its facilities, it will process third-party volumes to reduce the cost of ownership in the facility. The Company's primary business activities are not that of a midstream entity whose activities are focused on earning processing and other infrastructure-based revenues, and as such third-party processing revenue is netted against operating expenses in the MD&A. This metric is used by management to evaluate the Company's net operating expenses on a unit of production basis. Net operating expense per boe is a non-GAAP financial ratio and is calculated as net operating expense divided by total barrels of oil equivalent produced over a specific period of time. The calculation of the Company's net operating expenses is shown within the net operating expenses section within the MD&A for the quarter ended June 30, 2026.

Operating Netback and Operating Netback, Net of Derivatives

The Company's operating netback is determined by deducting royalties, net operating expenses and transportation expenses from petroleum and natural gas sales. The Company's operating netback, net of derivatives is

calculated by adding or deducting realized financial derivative commodity contract gains or losses from the operating netback. Derivative contract termination payments are included in realized derivative commodity contract gains or losses for the purposes of calculating the operating netback. The Company's operating netback and operating netback, net of derivatives are used in operational and capital allocation decisions. Presenting operating netback and operating netback, net of derivatives on a per boe basis is a non-GAAP financial ratio and allows management to better analyze performance against prior periods on a per unit of production basis.

Supplemental Information Regarding Product Types

References to gas or natural gas and NGLs in this presentation refer to conventional natural gas and natural gas liquids product types, respectively, as defined in National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities, except where specifically noted otherwise. Q2 2026, Q1 2026, Q4 2025 and full year 2025 average production volumes, respectively, were comprised of 64, 64%, 64% and 65% light & medium crude oil; 8%, 7%, 8% and 8% Heavy crude oil; 9% NGLs for all periods; and 18%, 19%, 19% and 18% natural gas. Q3 2026 forecast production at midpoint is anticipated to be comprised of ~65% light and medium crude oil, ~7% heavy oil, 9% NGLs & 18% natural gas.



Type Curve

Certain type curve disclosure presented herein represents estimates of the production decline and ultimate volumes expected to be recovered over time. "Results Projected" are based on a forward estimate of ultimate volumes to be recovered over time based on the initial 30 days average production data. "Guidance Well Type Curves" are the forecasted well performance used in setting the Company's guidance for expected results of the drilling program. Projected Results and Type Curves are useful in confirming and assessing the potential for the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter, are not necessarily indicative of long-term performance or of long-term economics of the relevant well or fields, including future wells to be drilled, or of ultimate recovery of hydrocarbons.

Boe Presentation

Boe means barrel of oil equivalent. All boe conversions in this presentation are derived by converting gas to oil at the ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of oil. Boe may be misleading, particularly if used in isolation. A Boe conversion rate of 1 Bbl : 6 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. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency ratio of 1 Bbl: 6 Mcf, utilizing a conversion ratio of 1 Bbl : 6 Mcf may be misleading as an indication of value.

Initial Production Rates

Initial production ("IP") rates disclosed herein, particularly those of short duration, may not necessarily be indicative of long-term performance or of ultimate recovery. Initial Production ("IP") rates indicate the average daily production over the indicated daily period.

FD&A Expenditures

The Company uses finding, development, and acquisition (FD&A) expenditures as a basis to monitor its capital efficiency. The Company's FD&A expenditures are calculated by adding A&D to capital expenditures less certain capitalized overhead costs. This measure calculates the capital cost outlay associated with the Company's exploration and development activities for the purposes of finding, developing and, when desired, acquiring its reserves.

Disclaimer

Oil & Gas Advisories



Oil and Gas Metrics & Reserve Definitions

This presentation contains metrics commonly used in the oil and gas industry which have been prepared by management, such as “FD&A costs”, “Net Asset Value”, “Recycle Ratio” and “Reserve Life Index”. These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

“FD&A Cost” represents finding, developing and acquisition cost as calculated as the sum of 2025 capital expenditures not including capitalized general and administration expenses (\$232.7 million) plus net acquisition costs (\$93.8 million), divided by the change in reserves within the applicable reserves category.

“Net Asset Value” has been calculated based on the estimated net present value of all future revenue from the Company's reserves, before income taxes as estimated by Ryder Scott effective December 31, 2025, including expenditures for abandonment, decommissioning and reclamation costs for all producing and non-producing wells and facilities, less net debt.

“Recycle Ratio” is calculated by dividing operating netback per boe by FD&A costs or F&D costs for a year.

“Reserve life index” or “RLI” is calculated by dividing the applicable reserves category volumes by 2025 fourth quarter production of 43,657 boe/d for 365 days as an estimation of how many years at a steady production level would the reserve volumes support.

“Production Replacement” is calculated by dividing reserves added by annual production, expressed as a percentage and shown by reserve category.

“Proved” reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

“Probable” reserves are those additional reserves that are less certain to be recovered than proved reserves. It is

equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

“Developed” reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

“Developed Producing” reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

“Developed Non-Producing” reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

“Undeveloped” reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

Reserve Assumptions: Reserve evaluation calculations are based on data and expected future production volumes as provided by third party independent evaluators Ryder Scott Company (the “Ryder Scott Report”) for year end December

31, 2025.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated in The Ryder Scott Report represent the fair market value of those reserves.

“Identified Inventory”: This presentation discloses “Booked” proved and probable drilling locations of the Ryder Scott Report for a total of 1,205 gross booked drilling locations. Further information of the location of the Booked drilling locations is listed in Saturn's news release dated March 11, 2026. An additional approximately 1,400 locations have been internally identified and are unbooked.

Burgess Creek & Triland identified drilling locations are based on internal estimates and updates to 3rd party reserve evaluators' independent evaluation for Burgess, with an effective date of March 31, 2026, and include 117 gross (113.1 net) booked locations. An additional approximately 216 gross locations (212.1 net) locations and approximately 35 OHML locations have been internally identified and are unbooked for Burgess, and approximately 27 gross locations and 5 OHML locations have been internally identified and are unbooked for Triland.

“Un-booked drilling locations” are based on Saturn's management review of its current land assets, geological and reservoir parameters that support potential economic development and do not have attributed reserves or resources.

Disclaimer

Oil & Gas Advisories



SUPPLEMENTAL INFORMATION REGARDING CORPORATE RESERVES ⁽¹⁾

Reserves Category	Light and Medium Crude Oil (Mbbbl)		Heavy Crude Oil (Mbbbl)		Conventional Natural Gas (MMscf)		Natural Gas Liquids (Mbbbl)		Total MBOE (Mboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved										
Developed Producing	58,263	53,786	10,312	8,785	104,631	95,276	8,387	7,630	94,400	86,081
Non-Producing	366	350	9	9	149	144	32	31	431	414
Undeveloped	34,185	31,541	1,100	1,058	61,631	55,206	3,665	3,307	49,221	45,107
Total Proved	92,813	85,676	11,421	9,853	166,411	150,626	12,084	10,968	144,053	131,602
Probable	49,394	45,439	4,951	4,219	91,491	81,792	5,985	5,290	75,579	68,580
Total Proved Plus Probable	142,207	131,115	16,372	14,071	257,902	232,418	18,068	16,259	219,631	200,182

SUPPLEMENTAL INFORMATION REGARDING CORPORATE RESERVES VALUES ⁽¹⁾⁽²⁾

Reserves Category	0% Discount	5% Discount	10% Discount	15% Discount	20% Discount
	MM\$	MM\$	MM\$	MM\$	MM\$
Proved					
Developed Producing	2,179.5	2,074.8	1,768.0	1,517.4	1,327.5
Non-Producing	15.5	11.0	8.1	6.1	4.7
Undeveloped	1,097.7	663.9	411.9	256.3	155.1
Total Proved	3,292.7	2,749.7	2,187.9	1,779.8	1,487.4
Probable	2,579.0	1,487.3	962.3	673.4	498.7
Total Proved + Probable	5,871.7	4,237.0	3,150.3	2,453.2	1,986.1

1) The estimated NPV does not represent fair market value of the reserves.

2) Price forecasts and foreign exchange rate assumptions of three consultant's (GLJ Ltd., McDaniel & Associates Consultants Ltd. and Sproule Associates Ltd.) average forecast as of January 1, 2026 as applied in the Ryder Scott Report.