2026

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PROSPERA ENERGY INC.

# Legacy Fields.
# Modern Solutions.
# Proven Results.

One year after EnerCom 2025 — the same wells, the same strategy, and the results to prove it.

**EnerCom Denver 2026 | TSXV: PEI | OTC: GXRFF**

ONE YEAR ON

# The EnerCom 2025 Report Card

What we showed you last August — and where it stands today

## 4 of 4

FEATURED WELLS STILL PRODUCING

Every well profiled at EnerCom 2025 is online today

## 30,217 bbl

CUMULATIVE OIL, THOSE 4 WELLS

Delivered since reactivation, all four combined

## $801,212

YTD REVENUE, THOSE 4 WELLS

Combined year-to-date sales revenue

## +352%

LUSELAND FIELD GROWTH

54 to 244 boe/d in 20 months

## The thesis has not changed. The evidence has.

Since November 2024: 17 reactivations executed for $1.64MM of capital, against $1.70MM of operating income generated. Program-wide cumulative free cash flow crossed into positive territory in June 2026 — the capital is back. Everything from here is return, against 140+ targets still in inventory.

WHO WE ARE

# Canadian Junior Heavy Oil — Built on Reactivation

Calgary-based operator, assets across Saskatchewan and Alberta

1. **745** boe/d
   Q2 2026 average, 98% liquids weighting

2. **400MM+** barrels OOIP
   Recovered to date at only 3-8% across much of the pool

3. **140+** reactivation targets
   41 identified as Tier 1 candidates

4. **$29.65** netback per boe
   Q2 2026 operating netback, up 170% from Q1 2026

## Where we operate

- **Cuthbert, SK**
  342 boe/d — the stable base
- **Luseland, SK**
  244 boe/d — the growth engine, +352%
- **Hearts Hill, SK**
  146 boe/d — waterflood upside
- **Brooks & Central AB**
  33 boe/d — optionality and running room

THE MODEL

# We don't drill for growth. We restart it.

Hundreds of wells across our acreage were shut in for reasons that no longer apply — high operating costs, poor sand management, absentee ownership. The oil never left.

01

## Screen

Licensed wells ranked by remaining oil in place, offset performance and reactivation cost

02

## Reactivate

Rod string, CHOPS pump upsize, recycle pump and sand suspension — weeks, not quarters

03

## Optimize

Daily fluid shots and wellhead cuts, staged speed-ups, chemical treatment

04

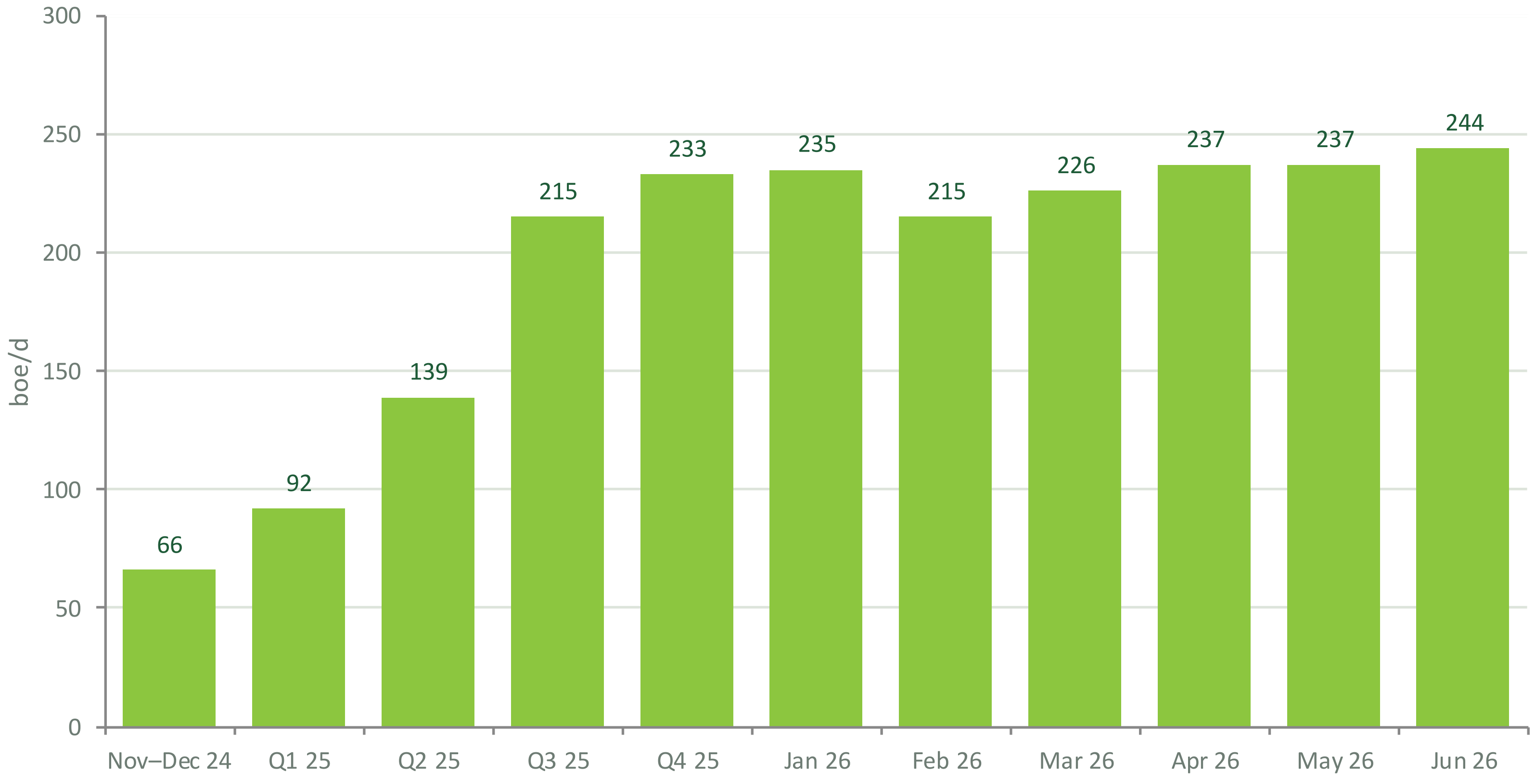
## Compound

Free cash flow funds the next batch. Target: 6 reactivations per month

**17 reactivations. $1.64MM of capital. Fully recovered.** Program-wide cumulative free cash flow turned positive in June 2026.

# Luseland: 54 → 244 boe/d

November 2024 through June 2026 — systematic CHOPS reactivation, pump optimization and active sand management




## +352%

**in 20 months**

Luseland's share of corporate production rose from 10% to 32% — now our single largest growth contributor.

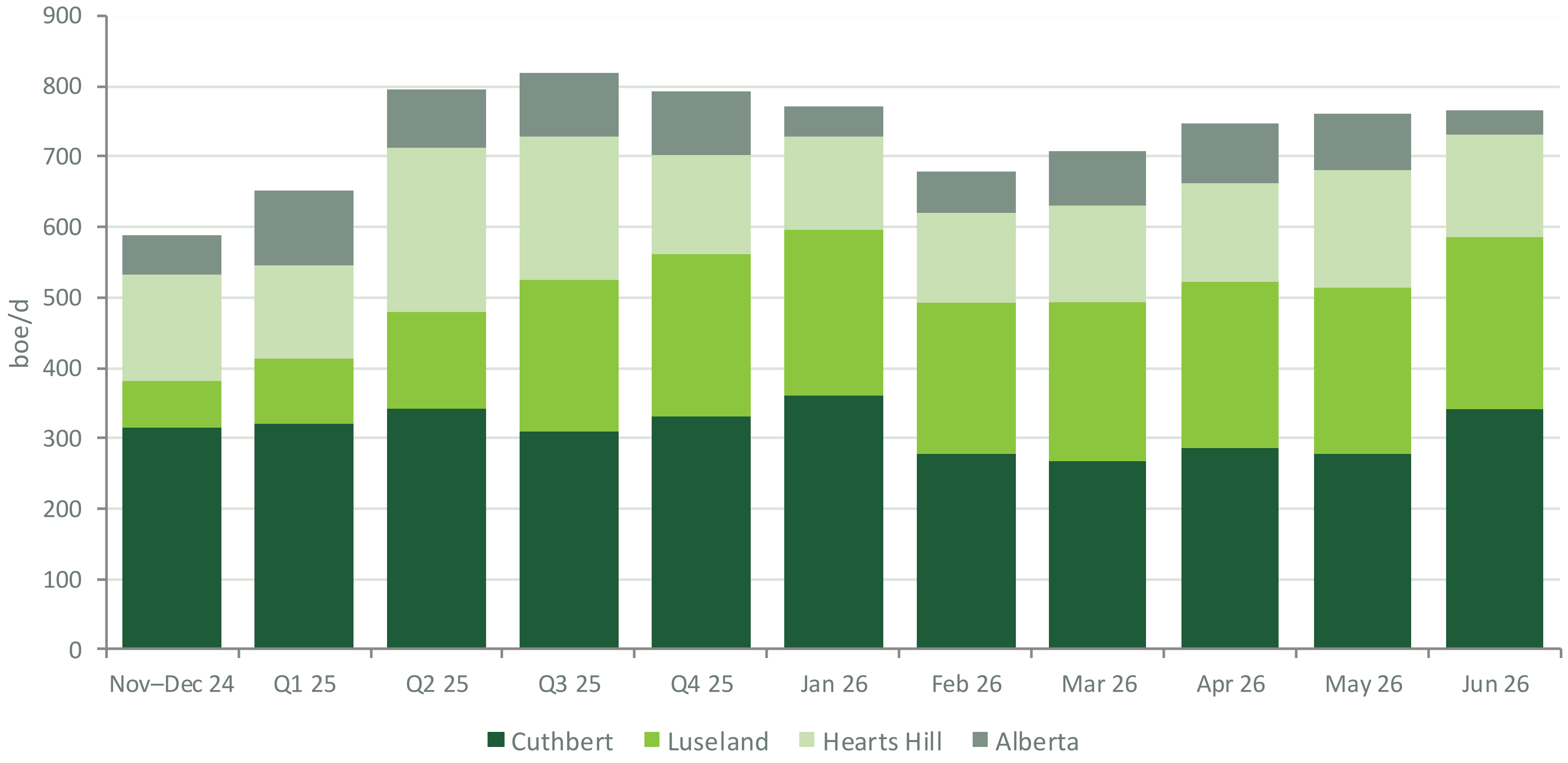
### What it took

- 17 wells reactivated
- Recycle pumps + sand suspension as standard practice
- **No new drills**

CORPORATE PRODUCTION

# Growth With a Stable Base

Gross production by area since the board and management transition, November 2024




## Reading the chart

### Cuthbert holds the floor

Waterflood-supported and remarkably flat through the whole period — 342 boe/d in June.

### Luseland does the climbing

The green band widens every quarter. This is where the reactivation capital went.

### Hearts Hill is next

Waterflood optimization is the 2026–27 program; 146 boe/d today with material upside.

### Alberta is optionality

Non-core weighting is deliberate — capital follows the best returns.

SAME WELLS, TWELVE MONTHS LATER

# The Class of 2025

The exact wells we profiled at EnerCom 2025 — and what they have done since

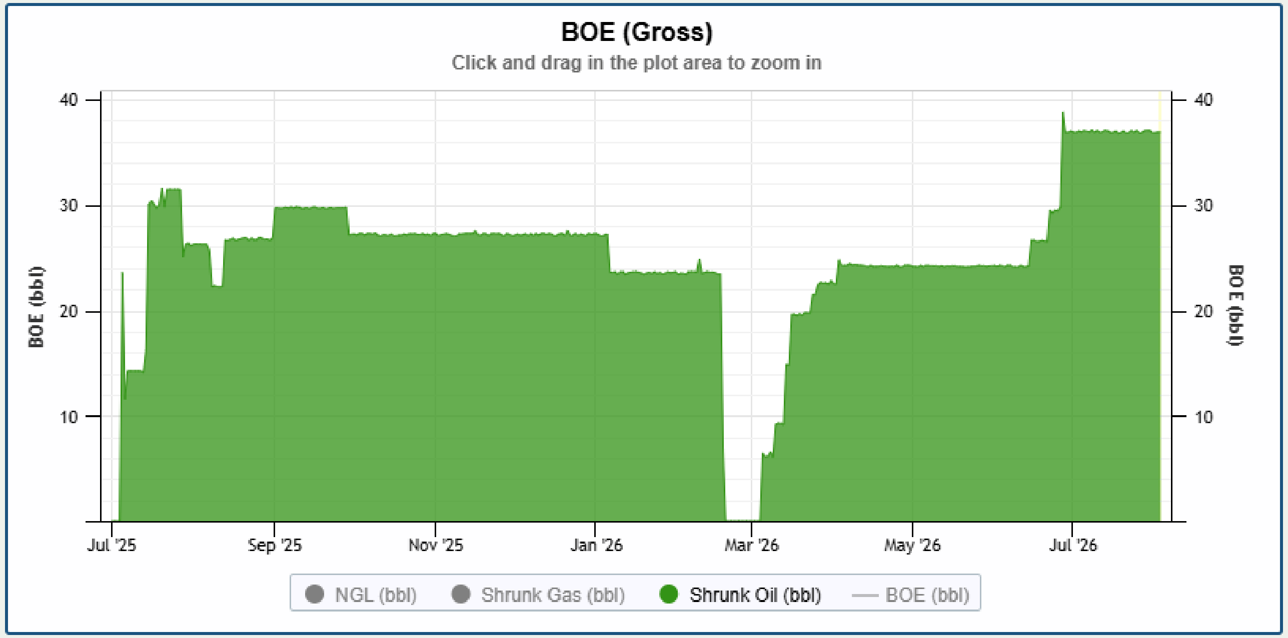
| WELL | AT ENERCOM 2025 | JULY 2026 | YTD REVENUE |
|---|---|---|---|
| **Luseland 10-07-36-25W3** | 45 days online<br>~26 bbl/d, upsized 30-series pump | **342 producing days**<br>**8,552 bbl cumulative** | **$292,663** |
| **Luseland 10-08-36-25W3** | 150 days monitored<br>~11 bbl/d under sand control | **460 producing days**<br>**8,156 bbl cumulative** | **$204,391** |
| **Luseland 07-33-35-25W3** | ~25 bbl/d, 9 JOF<br>recycle pump + sand suspension | **357 producing days**<br>**4,405 bbl cumulative** | **$70,642** |
| **Cuthbert 03-02-27-29W3** | ~13 bbl/d after waterflood<br>pattern change, 3x RPM | **539 producing days**<br>**9,104 bbl cumulative** | **$233,516** |

**30,217 barrels and $801,212 of revenue** from four idle wellbores. Two of them — 10-07 and 10-08 — have already returned 2.4x and 2.5x their reactivation capital.

LUSELAND — CLASS OF 2025

# 10-07-36-25W3

Luseland's top oil producer — and the program's fastest payout




**Paid out twice. A $50K workvoer in March 2026 was recovered inside a single month — the well then posted $101K of free cash flow in one month.**

AT ENERCOM 2025

Shown at EnerCom 2025 with just 45 days of history. We told you the upsized 30-series pump was handling large sand volumes and that the early rate looked sustainable.

JULY 2026

8,552 bbl delivered over 342 producing days at a 56.4% operating margin. Restarted July 2025 for $152.1K, paid out January 2026, and has returned $218.1K of net cash since.

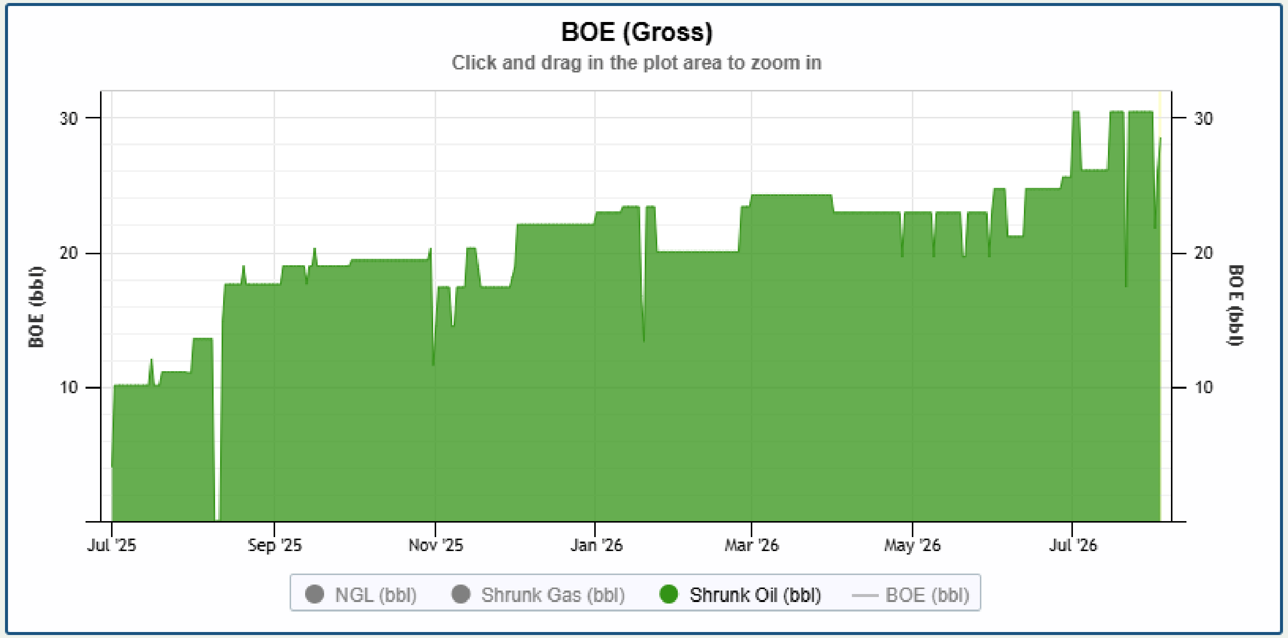
| 342 | 6 mo | 2.4x |
|---|---|---|
| PRODUCING DAYS | TO PAYOUT | CAPEX RETURNED |

**$292,663** YTD REVENUE

LUSELAND — CLASS OF 2025

# 10-08-36-25W3

Efficient runtime — 96% uptime since restart




**Patience paid. The restraint we showed you in 2025 is exactly why this well still runs at 96% uptime a year later.**

AT ENERCOM 2025

We showed 150 days of deliberately restrained production while we proved out sand control, with optimization through speed-ups and hot oil work just beginning.

JULY 2026

476 producing days out of 477 and 8,156 bbl delivered. Restarted March 2025 for $105.3K, paid out that December, and has returned $158.8K of net cash at a 47.4% margin.

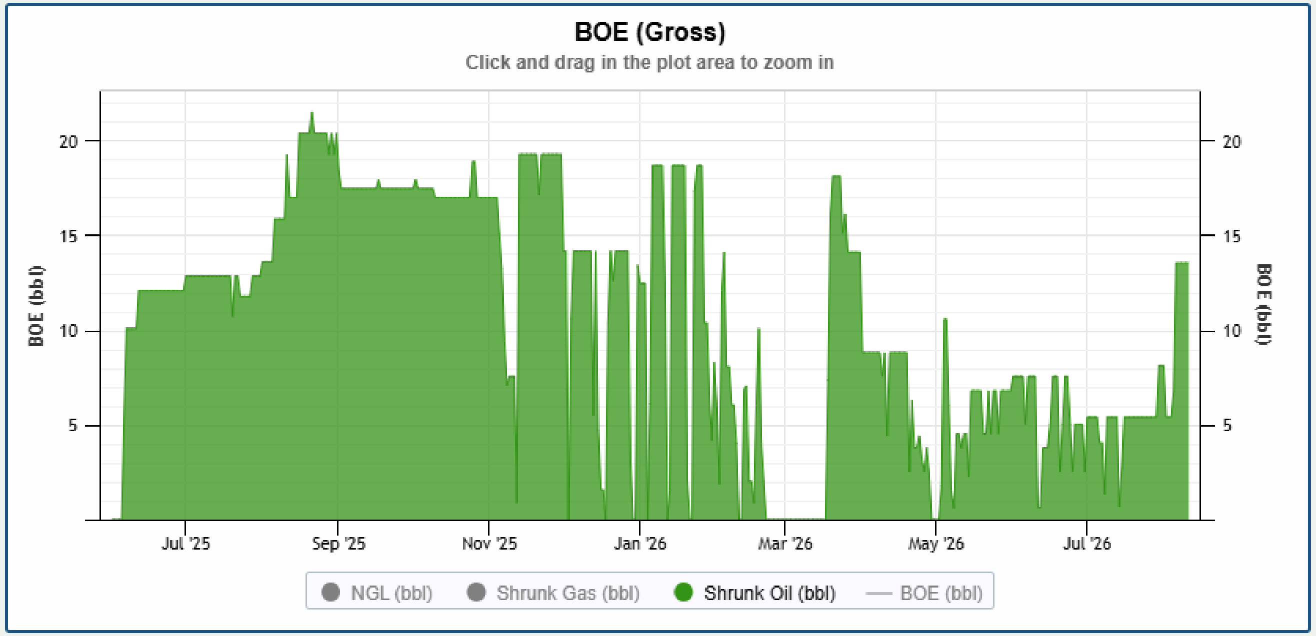
| 460 | 9 mo | 2.5x |
|---|---|---|
| PRODUCING DAYS | TO PAYOUT | CAPEX RETURNED |

**$204,391** YTD REVENUE

LUSELAND — CLASS OF 2025

# 07-33-35-25W3

Case study in active well management




**Not every well is a straight line. Every gap on that chart is a well that went down and a field team that brought it back — and it has still delivered 4,405 barrels.**

AT ENERCOM 2025

Presented as a well being gradually optimized through speed-ups, holding 9 JOF under a recycle pump with sand suspension injection and daily fluid-level monitoring.

JULY 2026

This well has gone offline repeatedly and been brought back every time — pump speed changes, chemical treatments, hot oil. It is our clearest example of engineering-led intervention holding a difficult well in production.

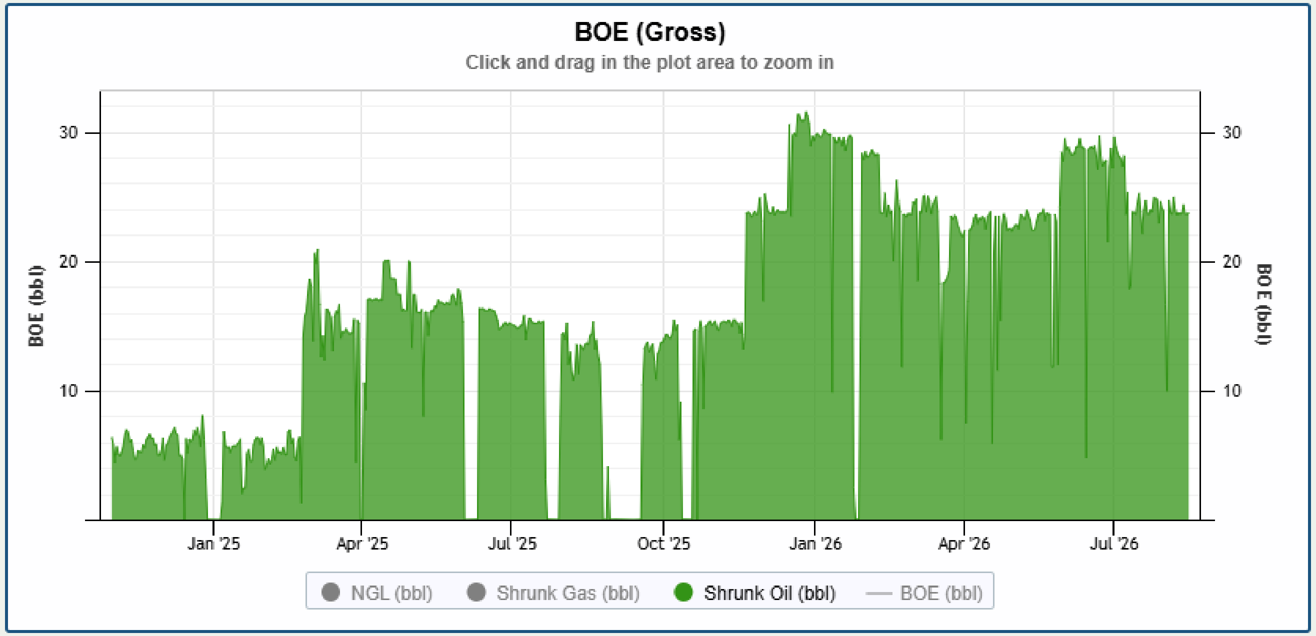
| 357 | 4,405 | Active |
|---|---|---|
| PRODUCING DAYS | BBL DELIVERED | MANAGEMENT |

$70,642 YTD REVENUE

CUTHBERT — CLASS OF 2025

# 03-02-27-29W3

Long-run accumulator — the highest cumulative oil of any well in this deck




**A waterflood pattern change and a pump speed-up. Two engineering decisions, no capital of consequence, and 9,104 barrels since the restructuring.**

AT ENERCOM 2025

Shown immediately after a waterflood pattern change and a 3x RPM speed-up, with production stepping up from roughly 5 bbl/d into the mid-teens.

JULY 2026

Second in 30-day oil for the Cuthbert area, with 9,104 bbl over 539 producing days. The chart shows the step-change holding through 2026 — average 15.12 bbl/d against a peak of 31.54.

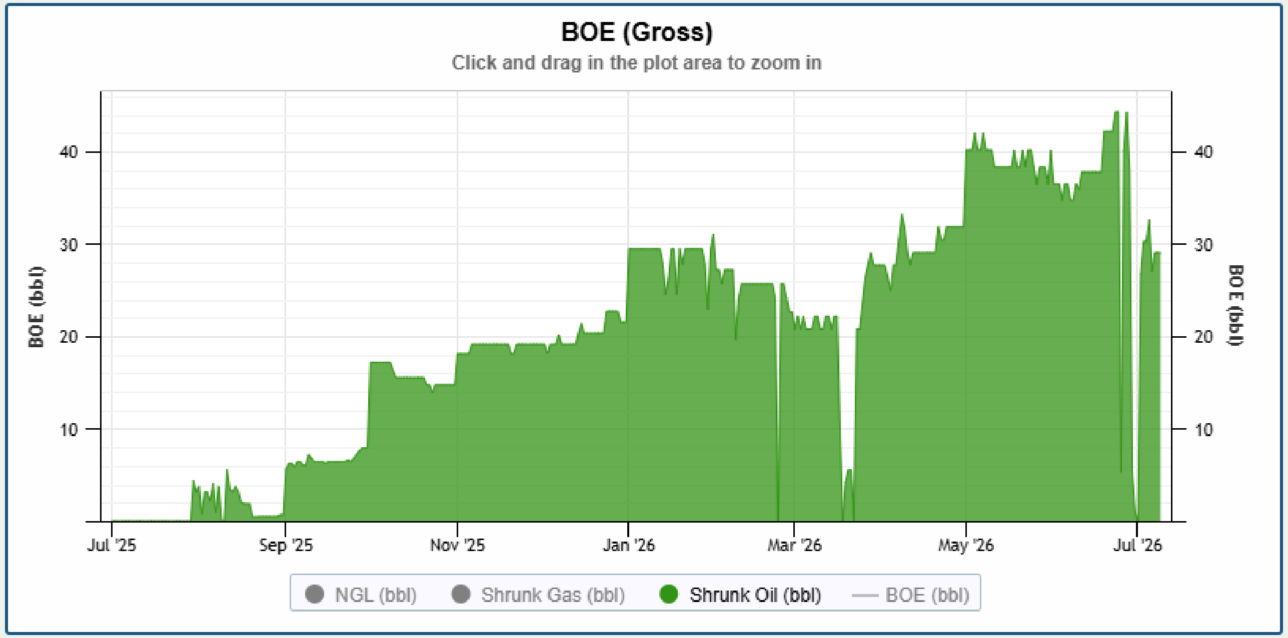
| 539 | 9,104 | 15.12 |
|---|---|---|
| PRODUCING DAYS | BBL DELIVERED | AVG BBL/D |

**$233,516** YTD REVENUE

LUSELAND — BEYOND THE CLASS OF 2025

# 16-07-36-25W3

Shut in for over twenty years — now the field's highest peak rate




**Twenty years shut in. Twelve months to payout. This is the single clearest argument for the 140 wells still in inventory.**

## THE STORY

This well sat shut in for more than two decades before we restarted it in March 2025. It now ranks first in the Luseland area for 30-day oil, with the highest peak daily rate in the group at 48.90 bbl against an average of 15.77 — and the chart shows it still climbing into mid-2026.

## REACTIVATION ECONOMICS

**$114.6K**
REACTIVATION CAPITAL

**$298.2K**
OPERATING INCOME

**2.6x**
CAPEX RETURNED

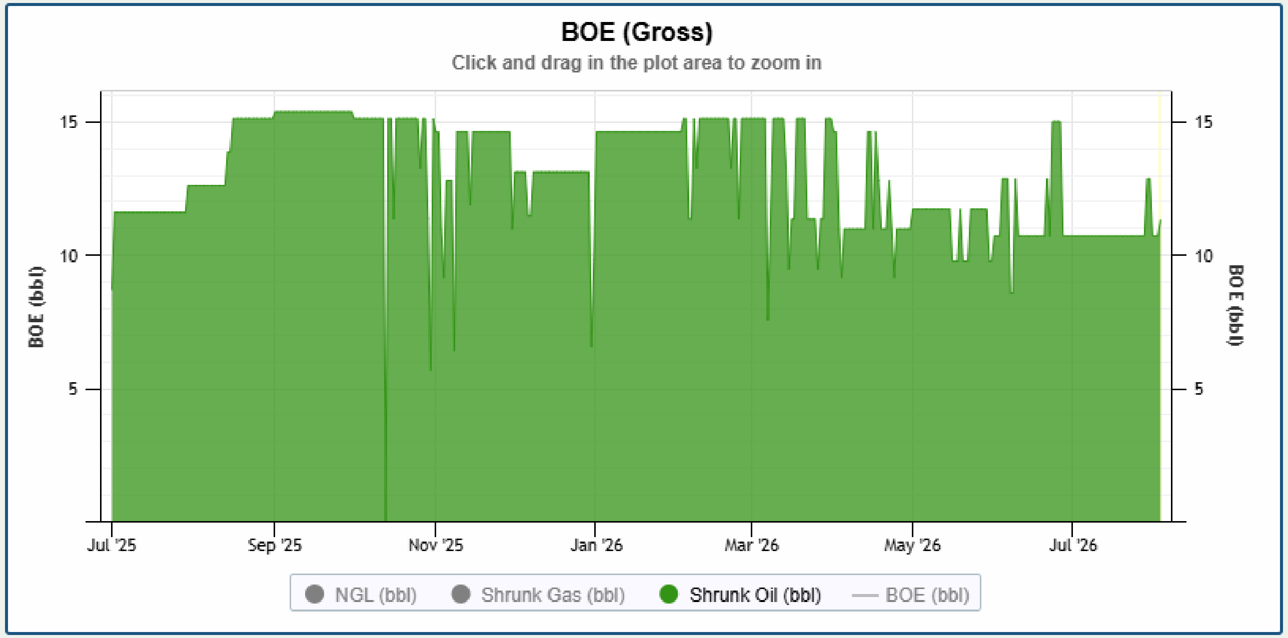
**50.0%**
OPERATING MARGIN

**$239,143** YTD REVENUE

LUSELAND — BEYOND THE CLASS OF 2025

# 01-17-36-25W3

The best cash-on-cash return in the entire program




**$61K in, $123K net cash back within fifteen months. Section 17 is now a priority target area.**

## THE STORY

Restarted in March 2025 for $61.7K — the cheapest reactivation in the program — and paid out in seven months. Very low water cuts and exceptional netbacks have held the production band tight, as the flat profile on the chart shows. It is the proof-of-concept for Section 17.

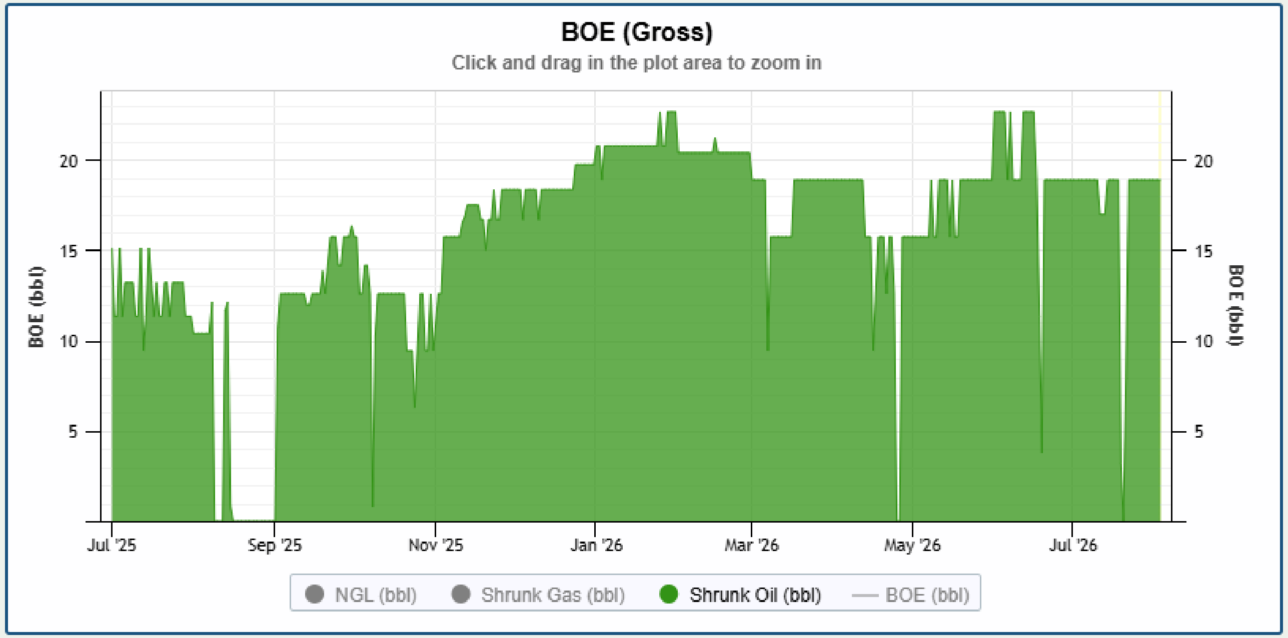
## REACTIVATION ECONOMICS

| | |
|---|---|
| **$61.7K** REACTIVATION CAPITAL | **$185.0K** OPERATING INCOME |
| **3.0x** CAPEX RETURNED | **7 mo** TO PAYOUT |

**$117,359** YTD REVENUE

# 03-09-36-25W3

The first reactivation of the program — and still paying




**The longest-running well in the program carries the lowest margin at 38% — and has still returned 1.7 times its capital. Everything we learned here made the wells that followed faster.**

## THE STORY

Restarted in November 2024, the first well of the reactivation program. It has accumulated 7,324 bbl across 460 producing days, and the step-change from late 2025 onward reflects the recycle pump installation that has since become standard practice across the field.

## REACTIVATION ECONOMICS

**$117.9K**
REACTIVATION CAPITAL

**$204.9K**
OPERATING INCOME

**1.7x**
CAPEX RETURNED

**13 mo**
TO PAYOUT

**$122,003** YTD REVENUE

THE PROOF

# Seven Wells Past Payout

Reactivation program economics since November 2024 — capital returned, well by well

| WELL | RESTART | SALES (BOE) | OP. INCOME | MARGIN | CAPEX | NET CASH · X CAPEX | PAYOUT |
|---|---|---|---|---|---|---|---|
| **D10-7-36-25** | Jul '25 | 9,343 | $370.2K | 56.4% | $152.1K | **$218.1K · 2.4x** | 6 mo · Jan '26 |
| **1-17-36-25** | Mar '25 | 5,436 | $185.0K | 47.0% | $61.7K | **$121.8K · 3.0x** | 7 mo · Oct '25 |
| **A16-7-36-25** | Mar '25 | 7,540 | $298.2K | 50.0% | $114.6K | **$183.7K · 2.6x** | 12 mo · Mar '26 |
| **D12-28-35-25** | Mar '25 | 3,388 | $149.5K | 57.6% | $59.4K | **$92.4K · 2.6x** | 11 mo · Feb '26 |
| **C10-8-36-25** | Mar '25 | 7,470 | $263.9K | 47.4% | $105.3K | **$158.8K · 2.5x** | 9 mo · Dec '25 |
| **3-9-36-25** | Nov '24 | 7,457 | $204.9K | 38.2% | $117.9K | **$87.1K · 1.7x** | 13 mo · Dec '25 |
| **10-18-36-25** | Jul '25 | 3,095 | $134.8K | 58.6% | $109.8K | **$25.1K · 1.2x** | 9 mo · Apr '26 |
| **PROGRAM — 17 WELLS** | | **52,951** | **$1.70MM** | **43.8%** | **$1.64MM** | **+$60.1K · 1.0x** | **Recovered Jun '26** |

**5 of 7** paid-out wells are past 2x cash-on-cash

**9.6 months** average payout, fastest six

**D10-7 paid out twice** — $50K recompletion recovered in one month

Q2 2026 RESULTS

# A Step-Change Quarter

Strongest quarter of the cycle

**$6.2MM**

REVENUE

**$91.17/boe realized**

+37% vs Q1 2026 · +26% vs Q2 2025

**$29.65**

OPERATING NETBACK PER BOE

**$2.0MM total**

+170% vs Q1 2026 · +30% vs Q2 2025

**$1.3MM**

FUNDS FLOW FROM OPERATIONS

**$1.5MM**

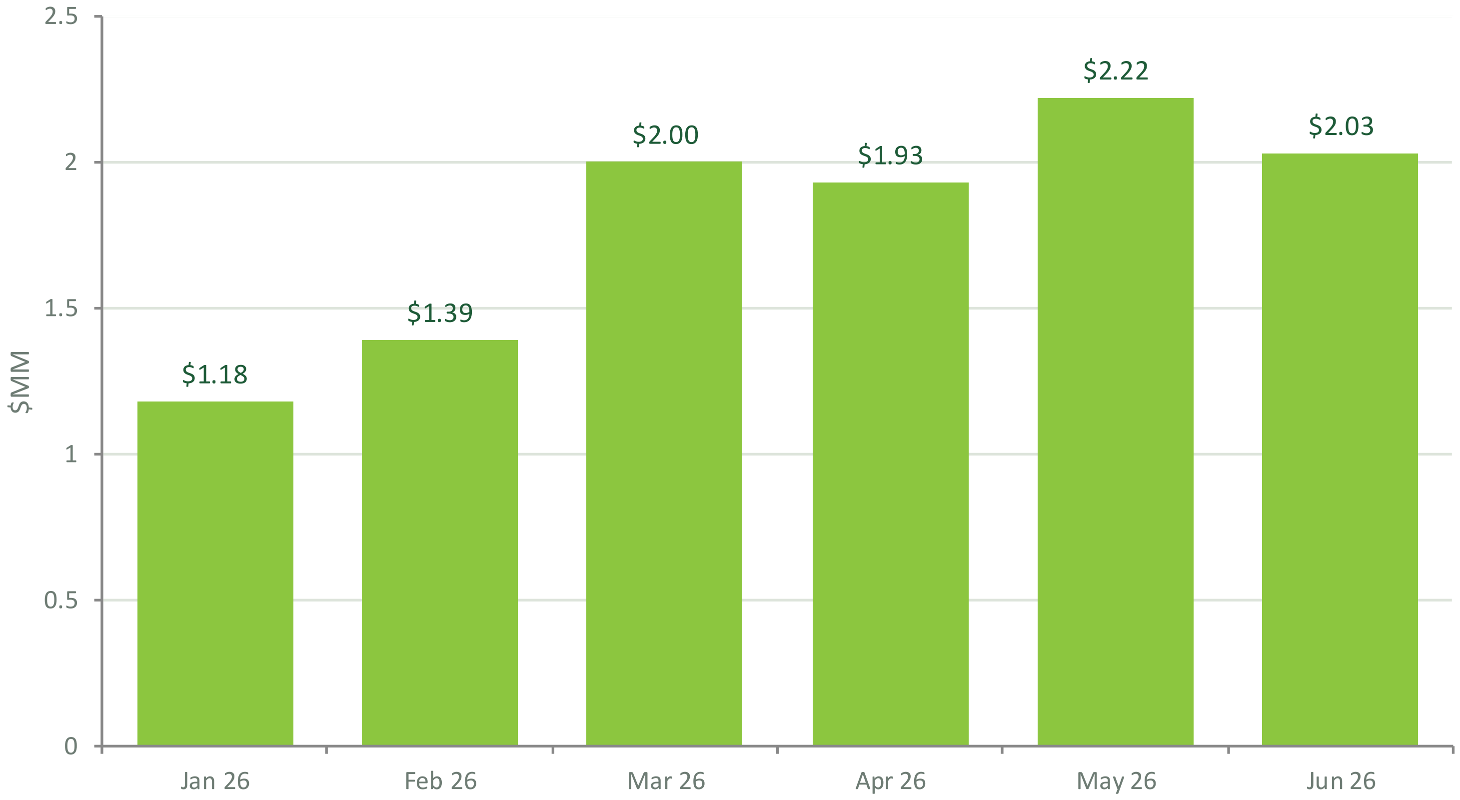
NET OPERATING CASH FLOW

**This is what the operating engine does on $0.6MM of capital, with fixed costs already covered and the remaining reactivation inventory untouched.**

CASH FLOW

# Record Quarter, Rising Monthly

Sales revenue, 2026 — a $6.18 million second quarter, our strongest on record




## $6.18MM

**Q2 2026 revenue at $91.17/boe realized**

Up 37% on Q1 2026 ($4.5MM) and 26% on Q2 2025 ($4.9MM) — delivered on $0.6MM of capital, before a dollar of the C$12MM program is deployed.

## +72%

**monthly revenue growth, January to June 2026**

$1.18MM in January to $2.03MM in June

MARGIN

# Same Barrels, More Dollars

Realized revenue per produced boe, Q2 2025 versus Q2 2026

**Q2 2025**

**$69.03**

revenue per boe · 782 boe/d
Operating netback $22.73/boe

**Q2 2026**

**$91.17**

revenue per boe · 746 boe/d
Operating netback $29.65/boe

**+32%**

**per barrel**

## Three forces, all pointing the same way

### Price

WCS averaged C$107.97/bbl in Q2 2026 against C$79.20 in Q1 — realized revenue rose to $91.17/boe from $69.75.

### Cost

Field opex down 5% sequentially to $47.45/boe on lower contract operator fees, field maintenance and road-use costs.

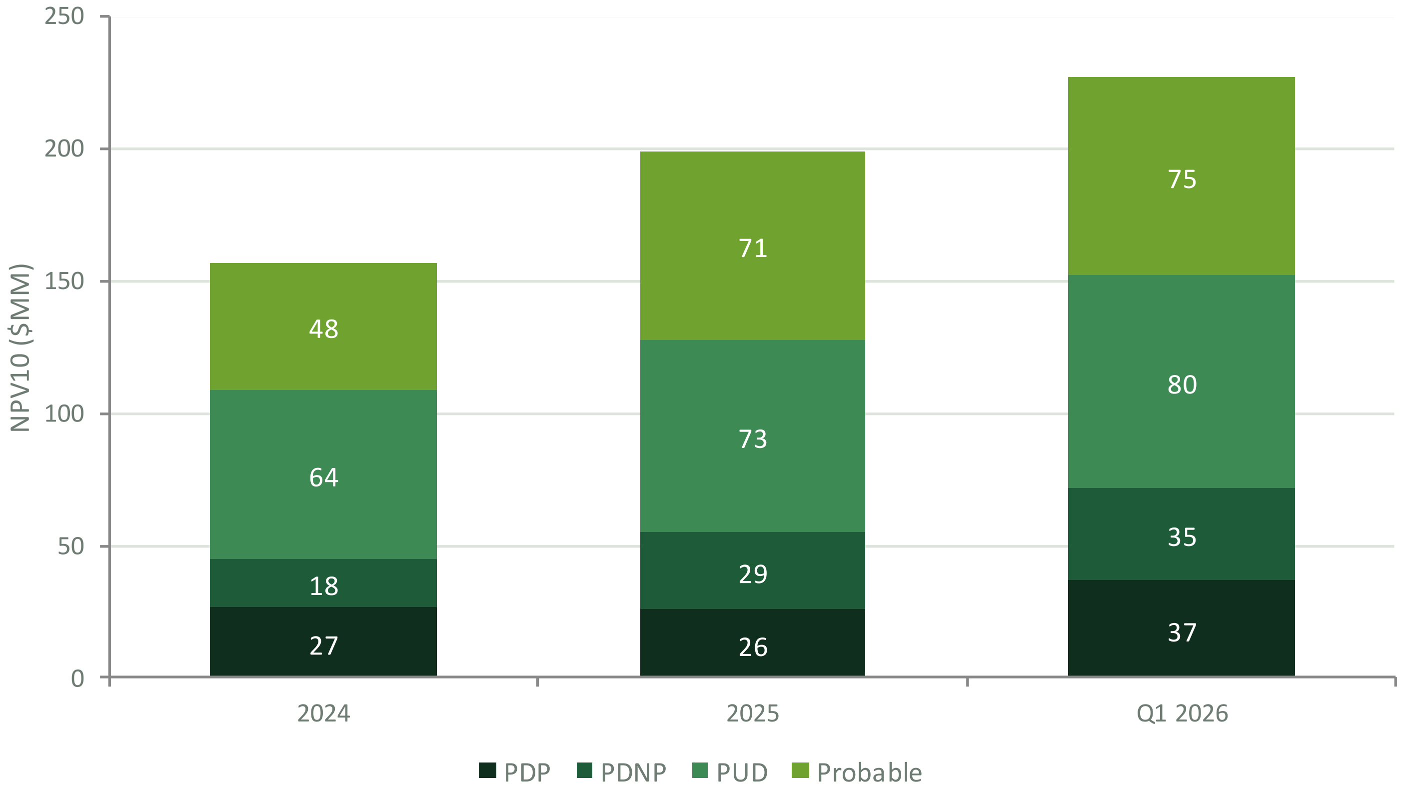
### Margin

Operating netback margin reached 33% of revenue against 17% in Q1 2026, on 98% liquids weighting.

RESERVES

# NPV10 Up 44% in Two Years

Before-tax cash flow discounted at 10%, by reserve category ($MM)




## $228MM

**2P NPV10 AT Q1 2026**

Total proved plus probable, up from $158MM at year-end 2024.

## $153MM

**TOTAL PROVED NPV10**

Up 38% over two years — growth concentrated in the developed categories.

## +37%

**PDP NPV10 GROWTH**

Producing reserves alone grew from $27MM to $37MM as reactivated wells built history.

WHAT'S LEFT

# 140+ Targets. 41 Tier 1.

Every well in this deck came out of the same inventory we are still drawing from

## 400MM+

BARRELS OOIP

Recovery to date sits at only 3-8% across much of the pool. The resource was never the problem.

## 352%

LUSELAND GROWTH

Screened and ranked candidates — 42 validated reactivation candidates sorted as Tier 1.

## 140+

TARGETS REMAINING

Identified across the portfolio after 21 reactivations completed since November 2024.

## 6

PER MONTH

Target reactivation cadence, funded from free cash flow and the current capital program.

**Program capital efficiency of roughly C$11,000 per boe/d. Seventeen completed reactivations returned their capital in an average of 9.6 months — the fastest in six.**

Payout measured as cumulative operating income against well-level reactivation capital. Actual results vary by well.

THE FINANCING

# The C$12MM Capitalization

Units at C$0.04 — one common share plus one two-year warrant at C$0.06

**C$12MM**

GROSS PROCEEDS

**300MM units at C$0.04**

C$30MM fully diluted with warrants exercised

**C$10MM**

INTO EXISTING WELLS

**No new drilling**

C$9MM reactivations · C$1MM workover & optimization

**900+**

BOE/D FUNDED

**More than doubles output**

C$10MM of field capital at the program's demonstrated C$11,000 per boe/d.

**6**

RESTARTS PER MONTH

**Cadence from close**

140+ targets in inventory, 41 ranked Tier 1 — years of running room.

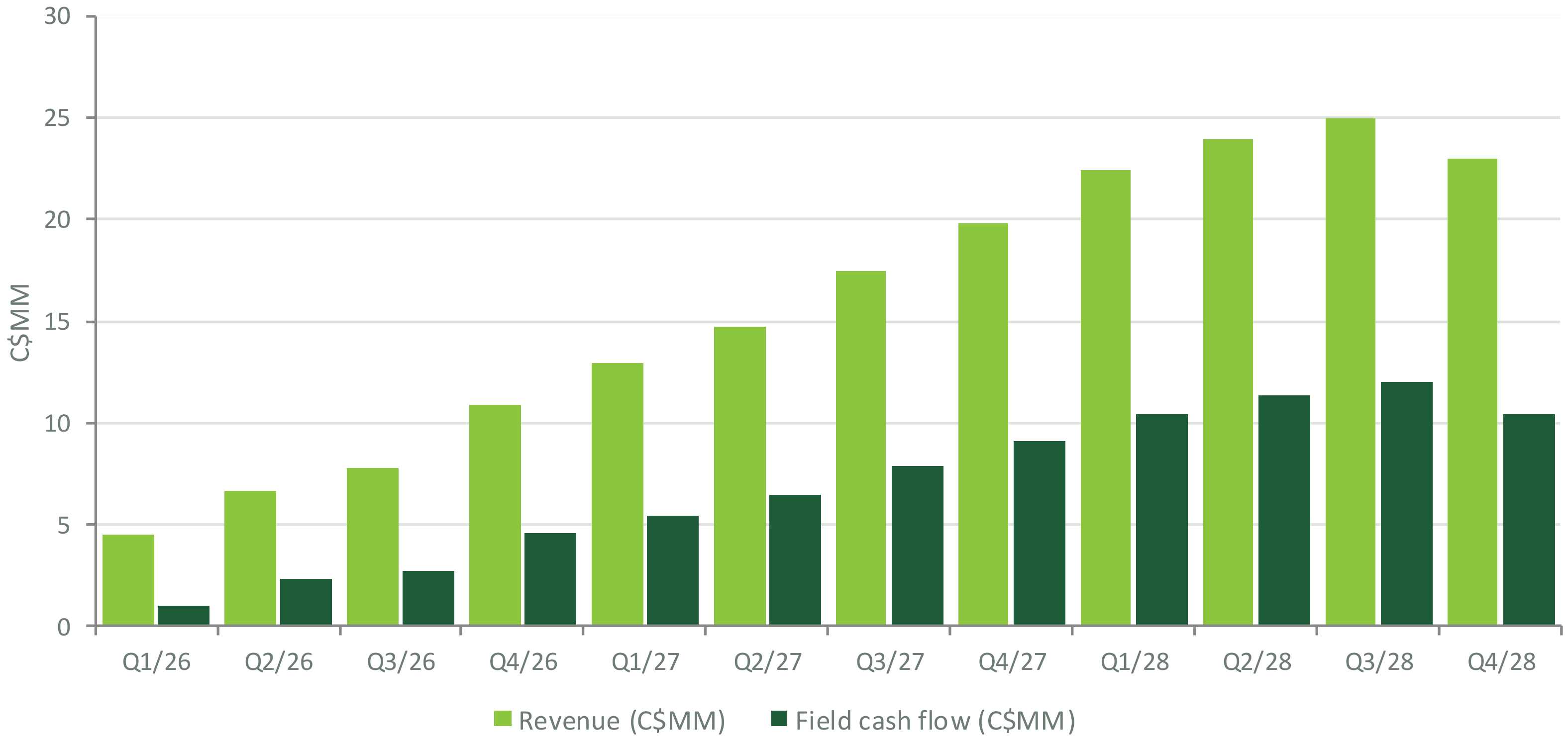
**Every dollar goes into wellbores that already exist. C$10MM of field capital funds roughly 900 boe/d of new high-netback production — from 745 boe/d today toward a step change in scale by 2028.**

Production added derived from C$10MM at the program's C$11,000 per boe/d. Forward figures are projections, not guidance.

FORWARD PROJECTIONS

# What It Builds To

Modelled revenue and field cash flow under the funded 2026–2028 development plan




**C$29.9MM**

**2026 revenue —** First cash-generating year

**C$64.9MM**

**2027 revenue —** +117% year over year

**C$94.3MM**

**2028 revenue —** +45% year over year

**C$44.2MM**

**2028 field cash flow —** Operating leverage at scale

Forward-looking figures from the 2026–2028 development model. Assumes the announced financing closes and warrants are exercised in full. Actual results will differ. See the advisory at the end of this presentation.

**Projections — not guidance**

THE INVESTMENT CASE

# What the Plan Returns

Targeted outcomes of the funded 2026–2028 plan at December 31, 2028

**4.3x**

TARGETED INVESTMENT RETURN

C$0.04 unit to a C$0.115 exit — share plus warrant value

**4.2x**

PRODUCTION GROWTH

779 to 3,310 boe/d by year-end 2028

**4.2x**

PDP RESERVE VALUE GROWTH

C$26.8MM to C$113.3MM NPV10

**2.9–6.6x**

RETURN ACROSS THE PRICE DECK

WTI US$70 to US$85 — downside case still 2.9x

## A re-rating driven by execution, not commodity tailwinds.

The base case holds a 4.0x DACF exit multiple — the Hemisphere Energy comp less leverage, track-record and liquidity discounts — and assumes the raise closes and warrants are exercised in full. What must be true is what this deck already shows in miniature: production delivery, balance-sheet cleanup and reserves growth. Forward-looking — see the advisory at the end of this presentation.

WHAT'S NEXT

# The wells we named last year have paid out multiple times, are producing at higher rates, and our strategy is ready to scale!

1

## Scale the cadence

Seven reactivations per month against a 140+ well target inventory, with 41 Tier 1 candidates already screened and sequenced.

2

## Scale to 3,310 boe/d by 2028

The funded development plan targets growth from 779 boe/d to 3,310 boe/d by December 31, 2028 at roughly C$11,000 per boe/d of capital efficiency.

3

## Hearts Hill waterflood

The optimization playbook proven at Cuthbert 03-02 applied across the Hearts Hill pattern — the next 03-02 is already identified.

4

## Finish the balance sheet reset

Sub-debt and GORR retired within 24 months of closing, payables down roughly 70% by 2028, and the senior facility refinanced on extended term.

# Forward-Looking Statements

This presentation contains forward-looking statements relating to the future operations of the Corporation and other statements that are not historical facts. Forward-looking statements are often identified by terms such as "will," "may," "should," "anticipate," "expects" and similar expressions. All statements other than statements of historical fact, including statements regarding future plans and objectives of the Corporation, are forward-looking statements that involve risks and uncertainties. There can be no assurance that such statements will prove to be accurate, and actual results and future events could differ materially from those anticipated.

Although Prospera believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on them. Risks include those associated with the oil and gas industry generally — operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; and health, safety and environmental risks — as well as commodity price and exchange rate fluctuations.

Forward-looking statements contained herein are made as of the date of this presentation, and Prospera does not undertake any obligation to update or revise them, whether as a result of new information, future events or otherwise, except as expressly required by Canadian securities law.

Prospera reports gross production at the first point of sale, excluding gas used in operations and volumes from partners in arrears, even if cash proceeds are received. Gross production represents Prospera's working interest before royalties; net production reflects its working interest after royalty deductions. Reserve values are before-tax cash flows discounted at 10% and are estimates only. Operating netback, funds flow from operations and operating income are non-GAAP financial measures that do not have standardized meanings under IFRS and may not be comparable to similar measures presented by other issuers. Well-level payout is measured as cumulative operating income against well-level reactivation capital. References to the announced equity financing, production and payable targets, and the retirement of subordinated debt and the GORR royalty are forward-looking and remain subject to TSX Venture Exchange approval and closing.