PetroTal

Investor Presentation
May 2026

InvestorRelations@petrotal-corp.com

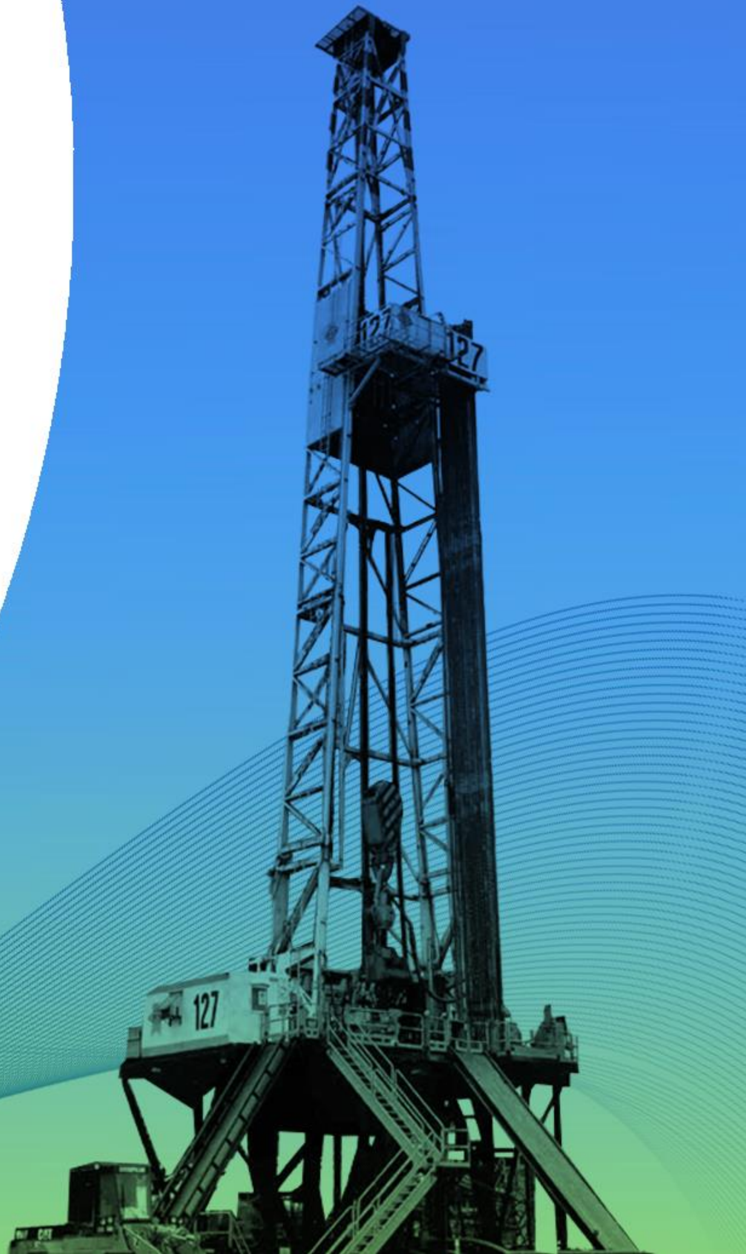
See additional details in the appendix
All figures in USD millions “m” unless otherwise stated
All production in “bopd” or “mmbbls” unless otherwise stated

Introduction to PetroTal

Corporate Summary

- PetroTal is a publicly-traded oil and gas company focused on the development of oil assets in Peru.
- Our flagship property is the Bretaña oil field located in the Marañon Basin of northern Peru.
- As an invested partner, we're working to help make Peru socially and economically stronger.

TSX : TAL | AIM : PTAL | OTC : PTALF



Production

12,000 bopd
2026 Guidance

14,907 bopd
Q1 2026 (Actual)

15,258 bopd
Q4 2025 (Actual)

19,473 bopd
FY 2025 (Actual)

Financial

$0.40/share USD
Share Price on Apr 30, 2026

920M
Basic shares

$360M
Market Cap

$104M
Available Cash[2,3]

2026 Guidance

$110-120M
Adjusted EBITDA

$180M
Net Operating Income

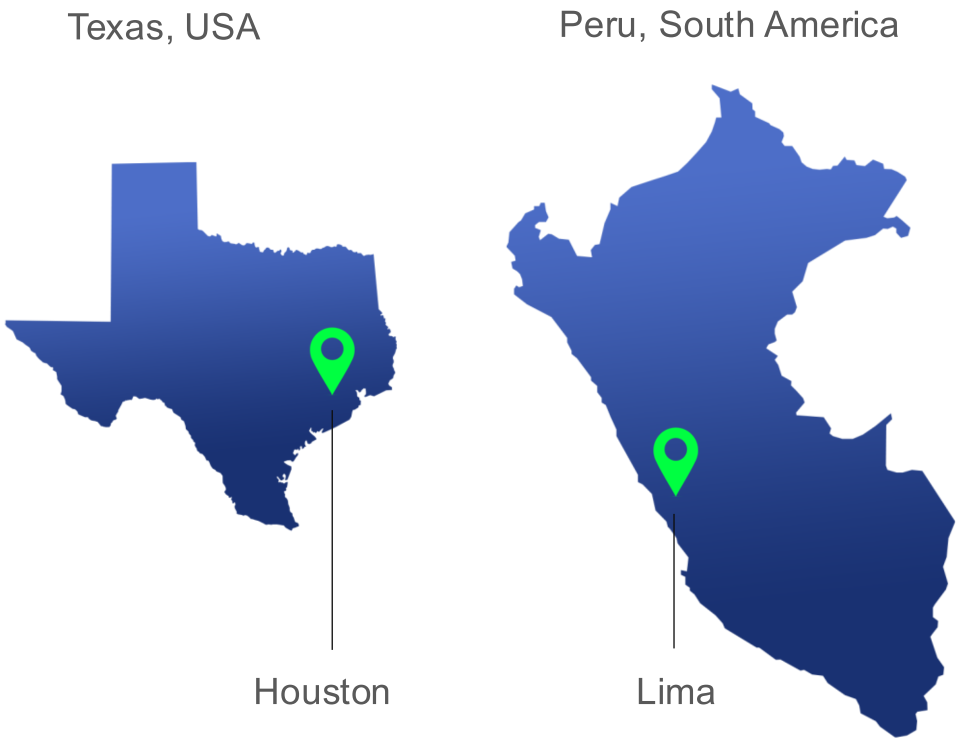
$80-90M
Capital Expenditures

$110-120M
YE26 Estimated Cash Balance

1. Actual through Mar 31, 2026 / 2. As of YE 2025 / 3. See footnotes and disclaimers for financial definitions. /

PetroTal overview

PetroTal operating presence



7th year of operation

$675m
Invested since inception through Q4 2025

31 mmbbls
Produced from Bretana since inception

$908m
Remaining 2P investment

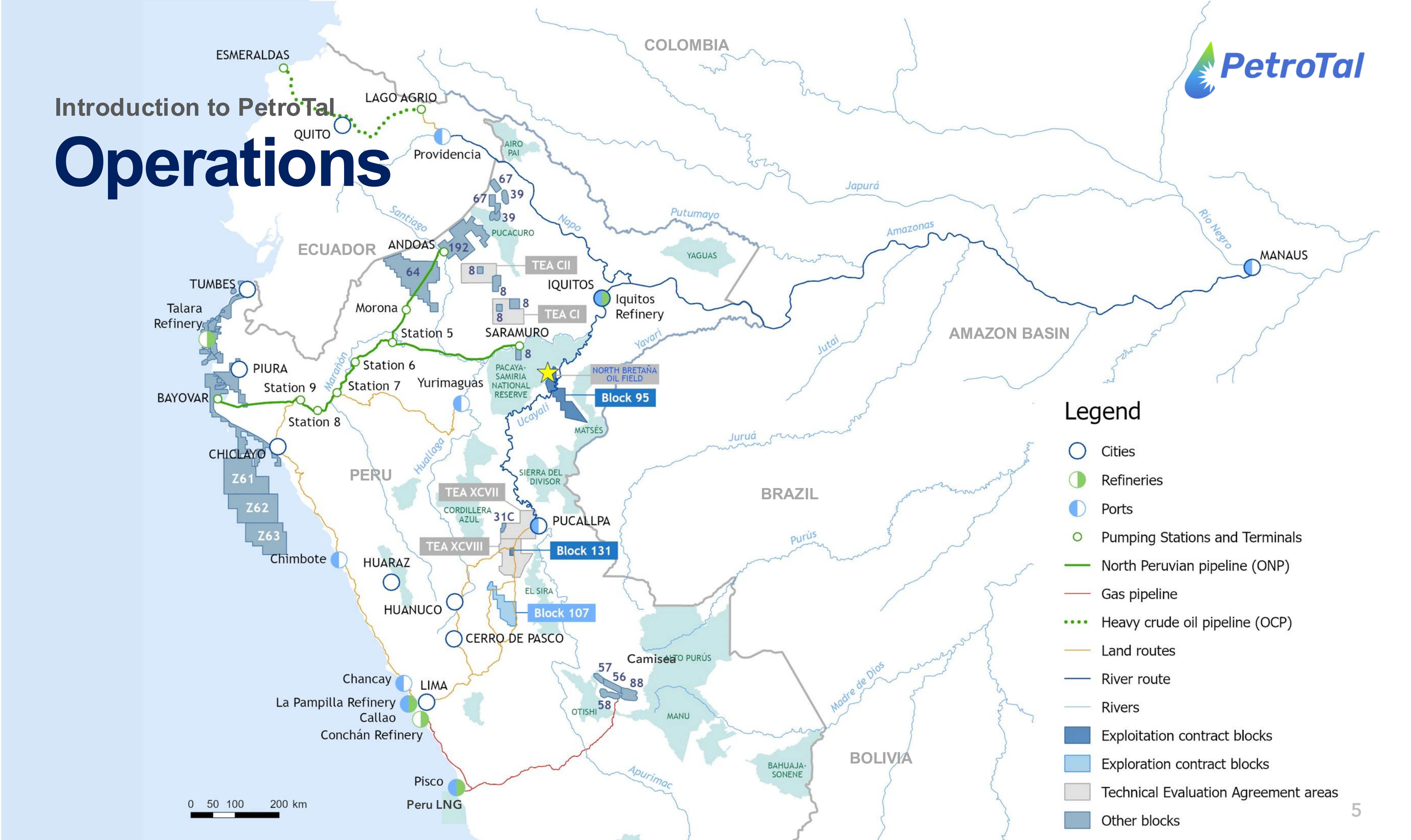
110 mmbbls
Remaining 2P reserves

$8.25/bbl[1,2]
Remaining booked 2P development costs

1. Calculated as $908 million remaining future 2P development costs / 110 mmbbls of 2P reserves
2. Existing 2P FD&A costs since inception are approximately $6.23/bbl

Introduction to PetroTal

Operations



Experienced leadership

Manolo Zúñiga
Director, President & Chief Executive Officer
- Petroleum engineer with over 30 years of experience helping shape and promote oil investments in Peru
- Former CEO of BPZ Energy

Camilo McAllister
Executive Vice President & Chief Financial Officer
- Financial executive with over 30 years of experience in international energy companies
- Former CFO of Constellation Offshore and Frontera Energy

Raul Farfan
Vice President Sustainability
- 25 years experience managing external affairs for resource companies throughout LATAM
- Previously External Relations Director for Newmont Peru

Jorge Osorio
Chief Operating Officer
- 37 years in the global oil & gas industry, most recently as VP Operations for Ecopetrol in Colombia
- Formerly with Ecopetrol, BP

Amaris Cardona
Chief People & Culture Officer
- More than 27 years experience in senior HR roles, most recently at LyondellBasell
- Previously VP of Human Resources for Stanley Black & Decker's oil and gas division

Emilio Acin Daneri
Vice President Commercial & Bus Dev
- Senior energy executive with extensive financial and commercial background in Latin America
- Formerly with CNOOC, Repsol, Pioneer, El Paso Marketing

Board of Directors

Mark McComiskey
Non-Executive Director and Chairman

Felipe Arbelaez Hoyos
Non-Executive Director

Eleanor Barker
Non-Executive Director

Jon Harris
Non-Executive Director

Gavin Wilson
Non-Executive Director

Manolo Zúñiga
Director, President & Chief Executive Officer

Emily Morris
Non-Executive Director

Denisse Abudinen Butto
Non-Executive Director

Introduction to PetroTal

Investment thesis

- PetroTal is Peru’s largest crude oil producer, with a demonstrated track record of disciplined operations and financial management across commodity cycles.
- Bretaña is a high-quality, conventional oil asset with the capacity to return to profitable growth as market conditions improve.
- PetroTal has returned over $150 million to shareholders since Q1 2023, demonstrating free cash flow capability and alignment through the cycle.
- 2026 represents a disciplined reset designed to protect value today and maximize upside tomorrow.

Investment Thesis

2026 budget objectives

Protect Liquidity

- Maintain minimum unrestricted cash balance of $60 million
- Align capital program with internal cash flows and available cash
- Target $30 million EBITDA though aggressive cost control

Reset Cost Base

- 21% reduction in opex/lifting costs
- 24% reduction in run-rate G&A expense
- Capital allocation biased toward near-term cash flow

Reposition For Growth

- Budget assumes resumption of drilling by October 1, 2026
- Two development wells planned for H2 2026
- Lay foundation for return to 20,000 bopd in 2027

PetroTal's 2026 budget is designed to bridge the Company through a period of low oil prices while preserving the option value of Bretana

Investment Thesis

2026 budget highlights

January 2026 Guidance

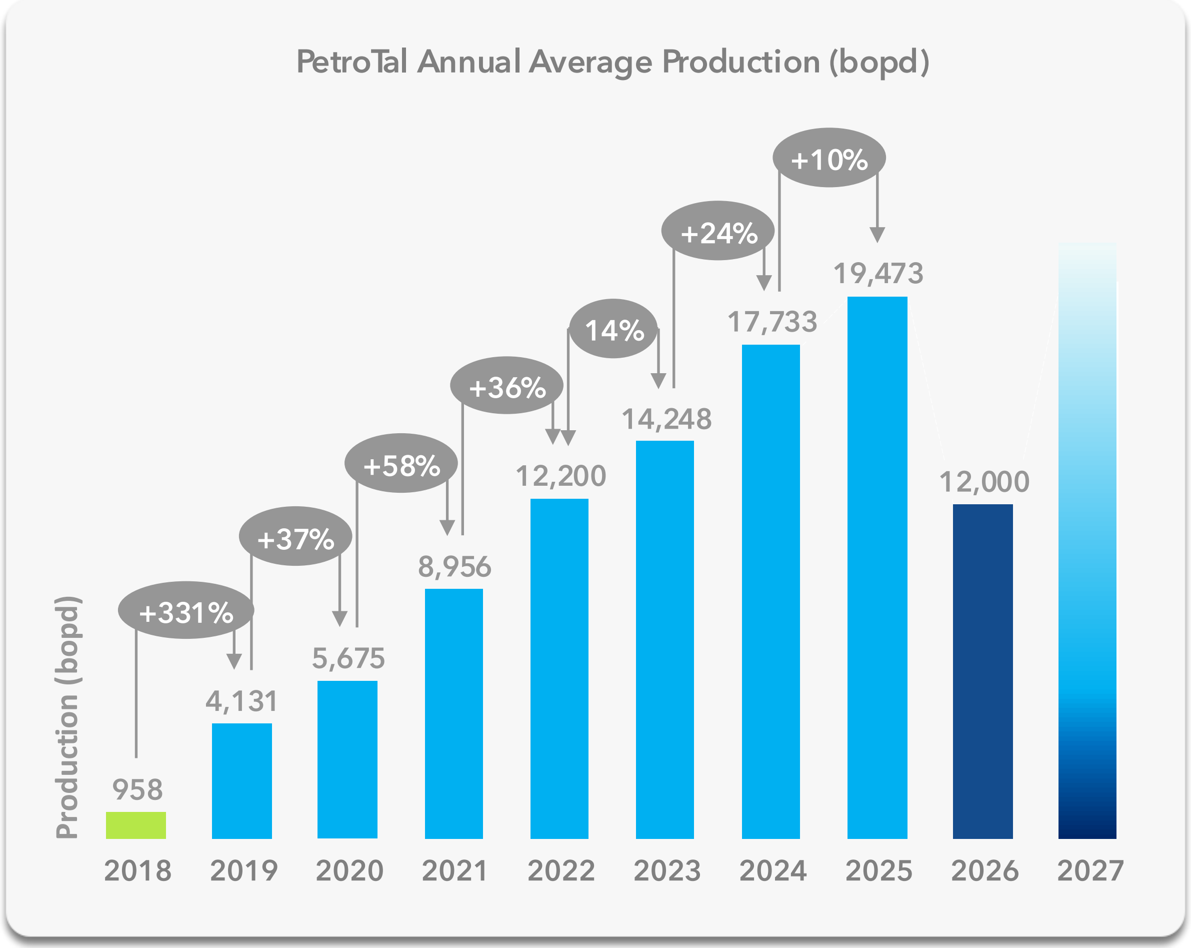
$80-90 million capital program
Development drilling to resume in H2 2026

$30-35 million
Remaining erosion control expense

20-25% reduction
In opex / G&A expense

$60 million
YE 2026 ending available cash balance

>20,000 bopd
Target production capacity in 2027



Investment Thesis

Bretaña: strategy reset

1) Protect Liquidity and Financial Flexibility

- Capital and financing decisions governed by minimum ~$60 million cash floor
- Proactive refinancing and asset monetization to manage financial resilience
- Willingness to defer growth to avoid balance-sheet stress

2) De-Risk Operations Before Re-Accelerating Growth

- Shift to third-party drilling to reduce capital exposure and execution risk
- Built-in contingencies to protect schedules and cost assumptions
- Focus on high-certainty execution over aggressive timeline

3) Reset the Cost Structure Structurally, Not Temporarily

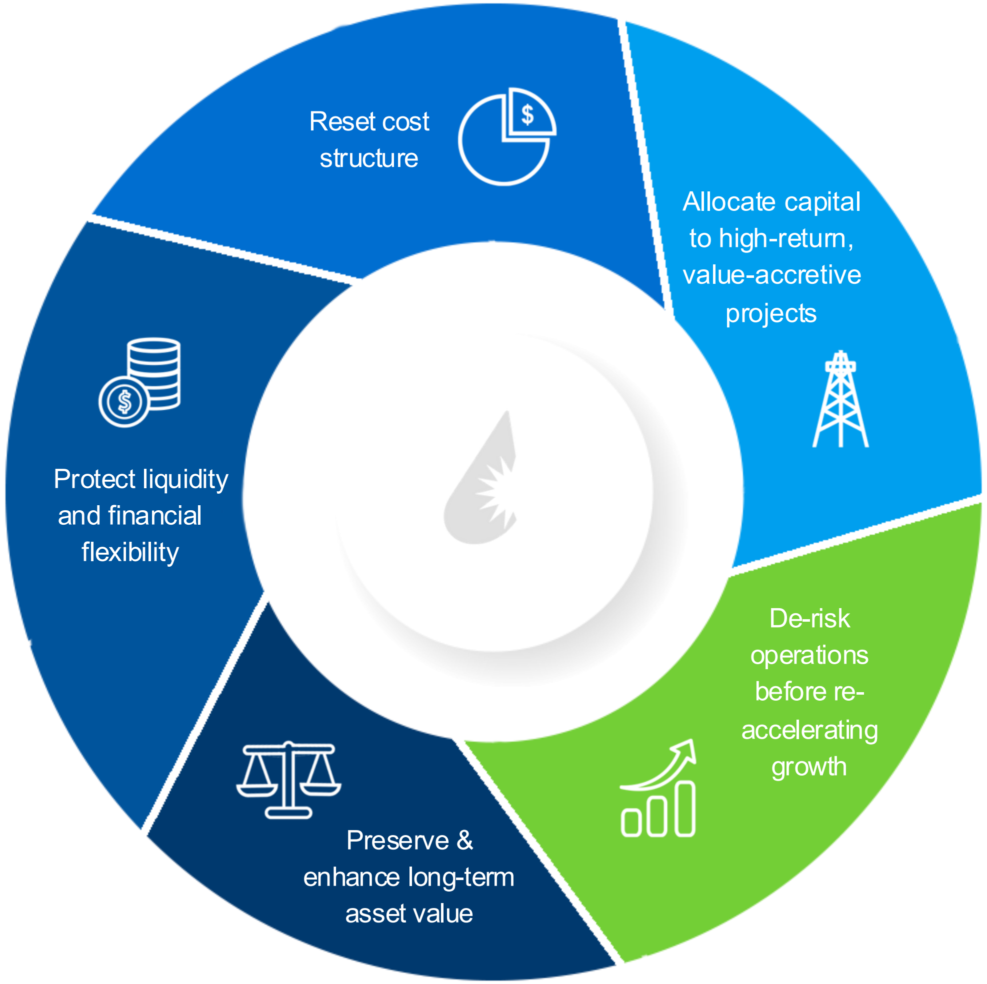
- Meaningful reductions in OPEX, G&A, and headcount
- Renegotiated service contracts and drilling efficiencies embedded in the base plan
- Lower breakevens to improve resilience and future oil price leverage

4) Preserve and Enhance Long-Term Asset Value

- Phased infrastructure expansion to avoid production sterilization
- Continued investment in erosion control and water handling capacity
- Protects the ability to return to >20,000 bopd without sacrificing NPV

5) Allocate Capital to High-Return, Value-Accretive Projects

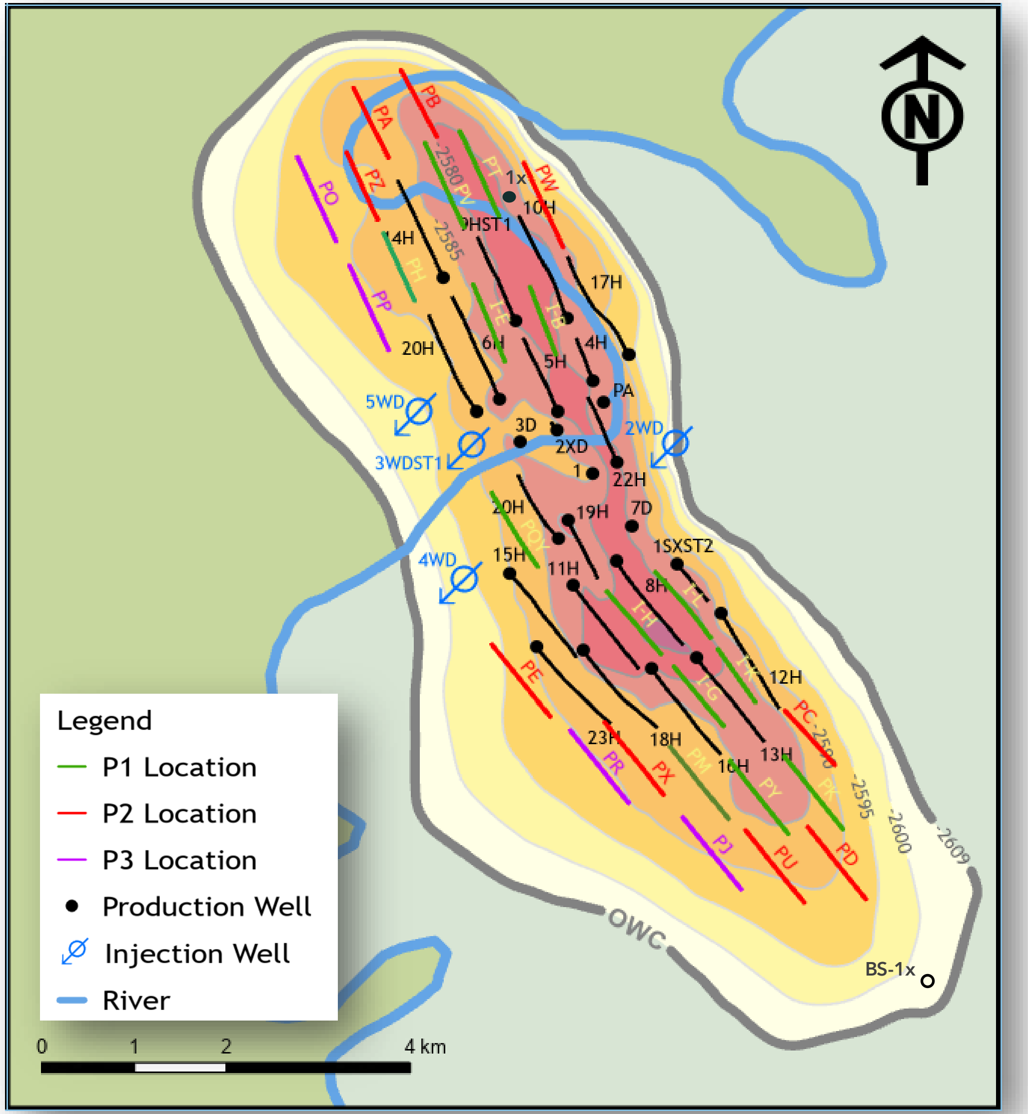
- Eight-well program delivers strong economics even under stress scenarios
- Capital discipline ensures growth is NPV-positive across the cycle
- Growth is paced to liquidity, not oil price optimism



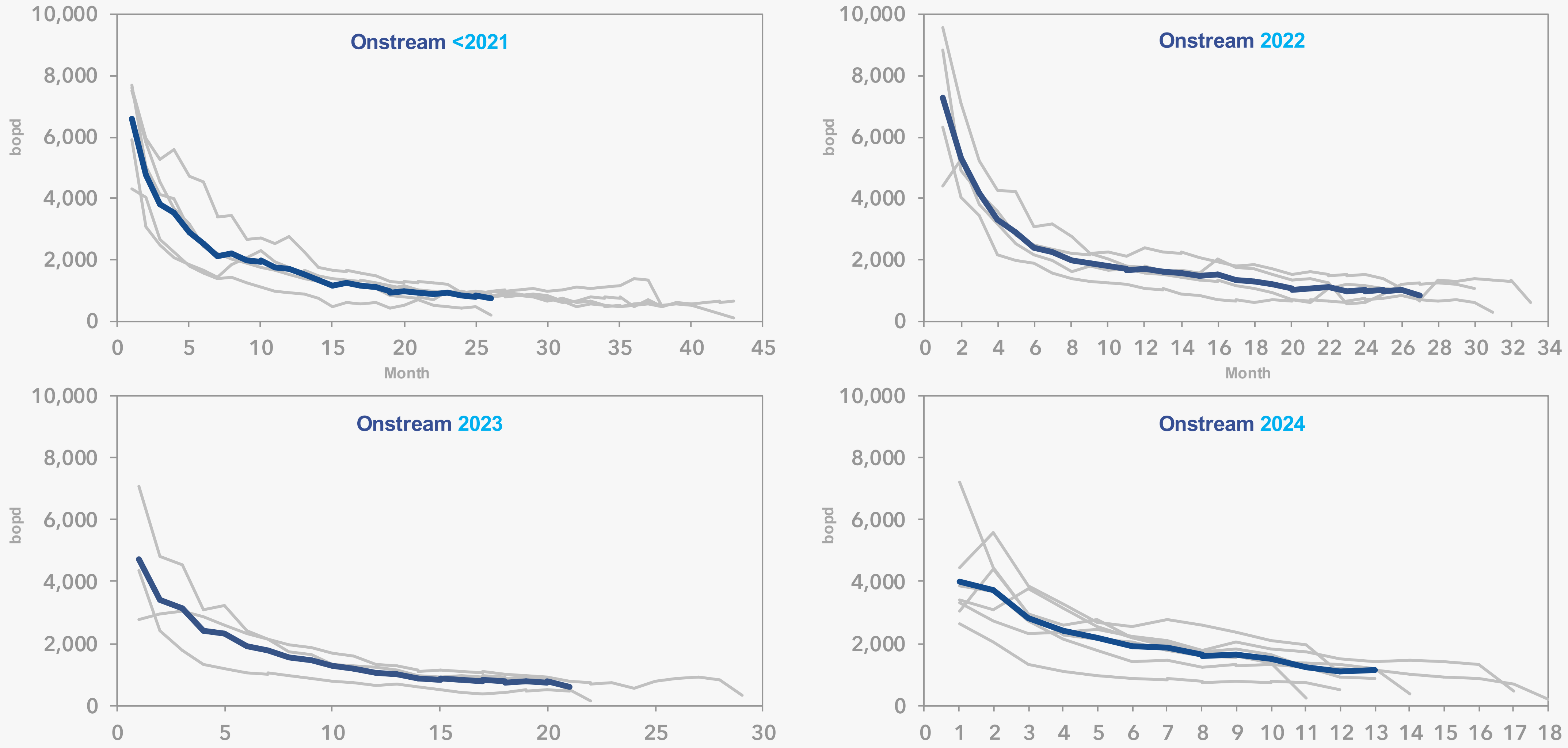
Operational **Performance**

Repeatable conventional oil

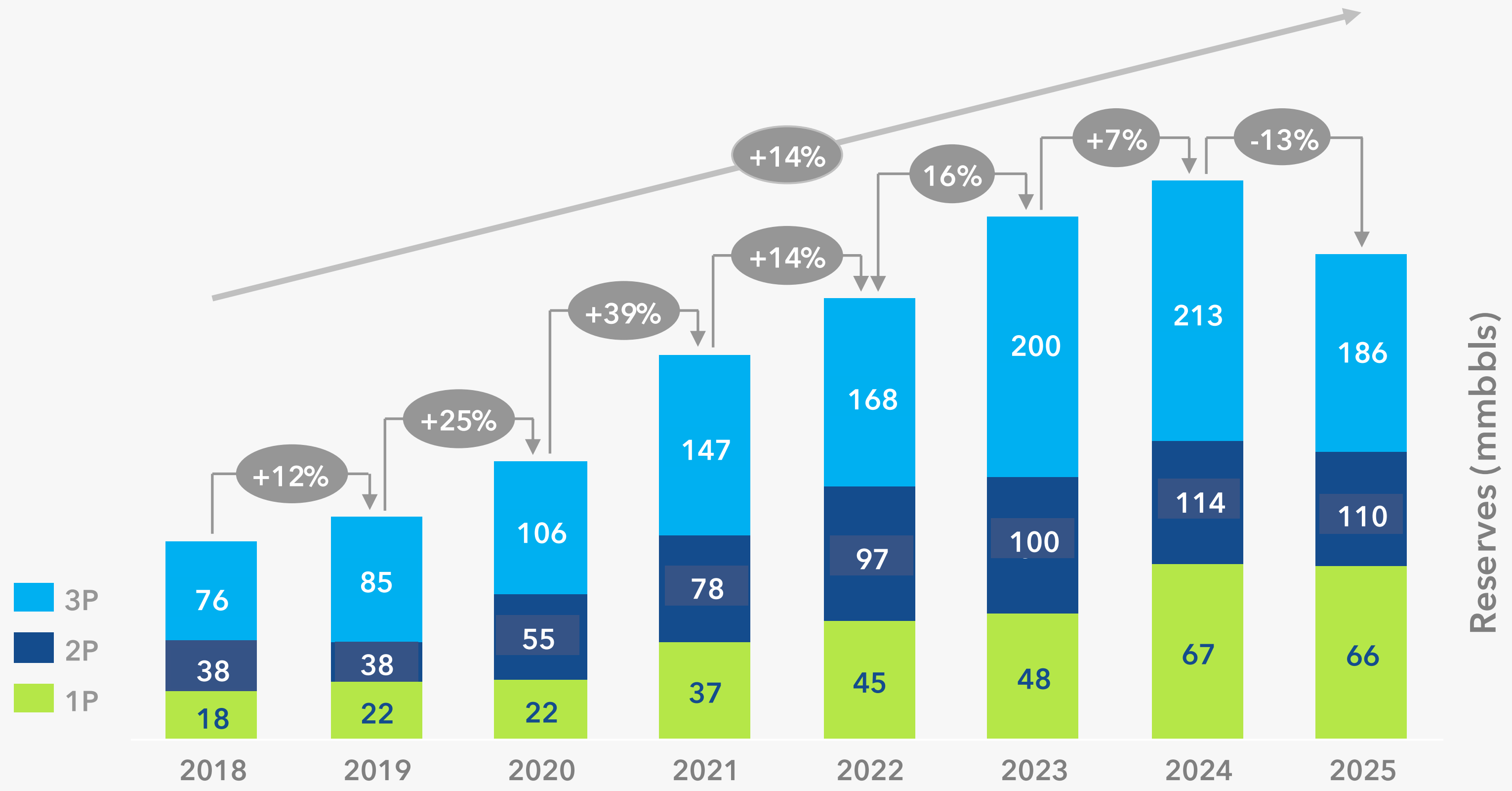
- Vivian reservoir – Massive fluvial sands with excellent reservoir quality
- OOIP unchanged at 494 mmbbls (2P) at YE25, compared to 329 mmbbls (2C) at YE17
- Analogous fields have recovery factors of 22-42% vs Bretaña at 27%
- 5 and 6 new wells (1P and 2P, respectively) added to the development plan at YE25
- 1P and 2P reserves cases have 37 and 46 producing wells
- Field Size: 15,028 acres



Consistent type curve



Reserves growth



2P After Tax NPV10 (millions)	$326	$746	$621 (Covid impacted)	$1,020	$1,509	$1,639	$1,720	$1,167

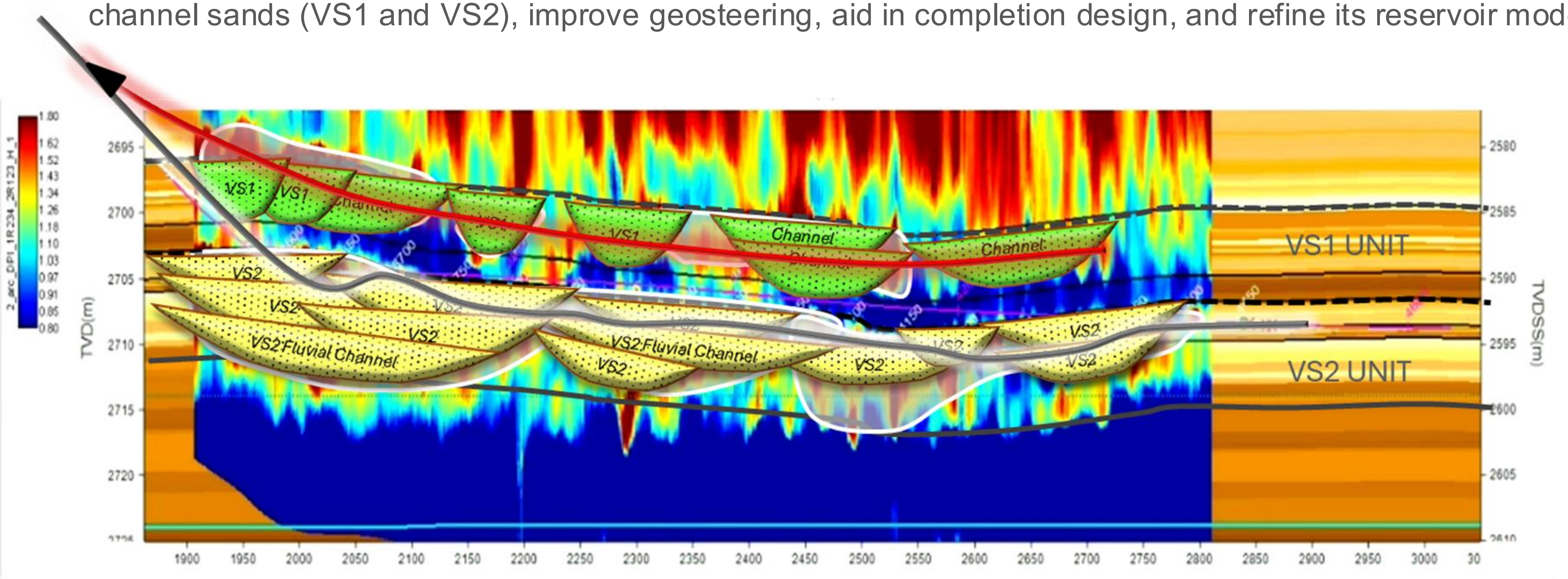
9.3 years
Estimated 1P reserve life index

$1.2 Billion 2P
After tax PV10 valuation of $1.89/share

96.5 mmbbl
1P EUR – including 30 mmbbls produced to date

Development potential

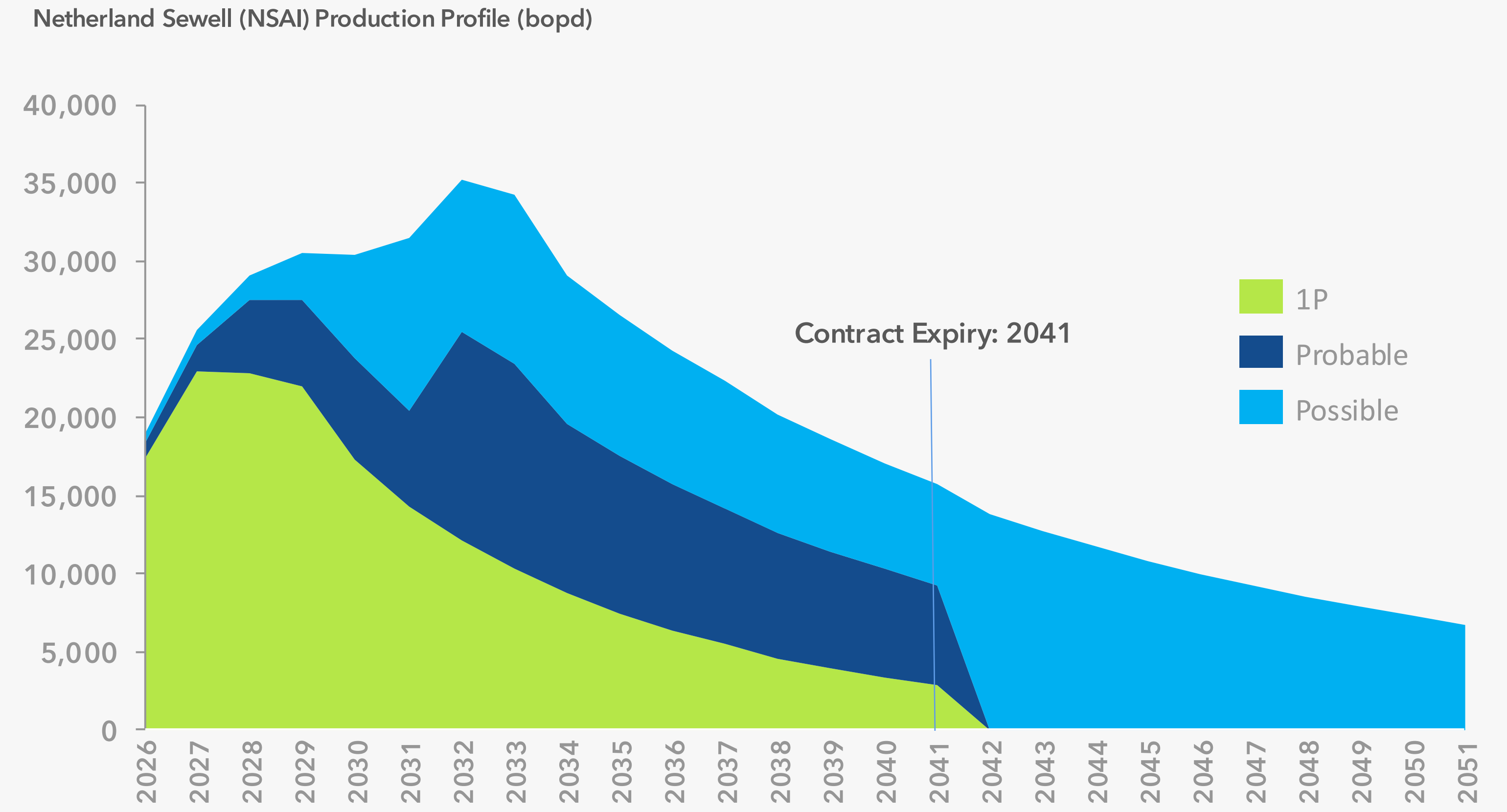
- VS1 Unit: for the first time at Bretaña, PetroTal used the 20H well to drill a lateral into the upper Vivian VS1 unit, where a brief production test in August 2024 flowed 320 bopd.
- Independent estimates allocated ~28% of Bretaña of OOIP at YE24 (659 MMBbl[1]) to the VS1 unit; nominal volumes were included in 3P reserves, pending additional production testing.
- PetroTal has been using SLB's new Geosphere HD reservoir mapping-while-drilling technology to identify fluvial channel sands (VS1 and VS2), improve geosteering, aid in completion design, and refine its reservoir model.



(1) Bretana booked 2P OOIP as of YE24

Growth **Strategy**

Core asset production profile



(1) Possible case assumes contract extension to 2051; of the 75 mmbl included in Possible reserves at YE25, approximately 36 mmbbl are produced beyond the expiration of the current license contract in 2041.

> 10,000 bopd

Full reserve life, in 3P case

35,000 bopd

Possible peak production

20,000-25,000 bopd

Ability to flatten peak production, into multi-year production profile

Infrastructure Investments

Erosion control

Bretana: mid-2025

Bretana: The Solution

Erosion control

Recent Construction Activity: Bretana, Peru (Q1 2026)

Growing PetroTal

Growth opportunities

- Peru’s Marañon and Ucayali Basins have been underexplored for hydrocarbons
- Near-term development upside at both Bretana and Los Angeles field
- Multiple prospects and leads from existing portfolio Blocks 95, 107 and 131

Expansion

Block 95

Expansion beyond Bretaña at Block 95

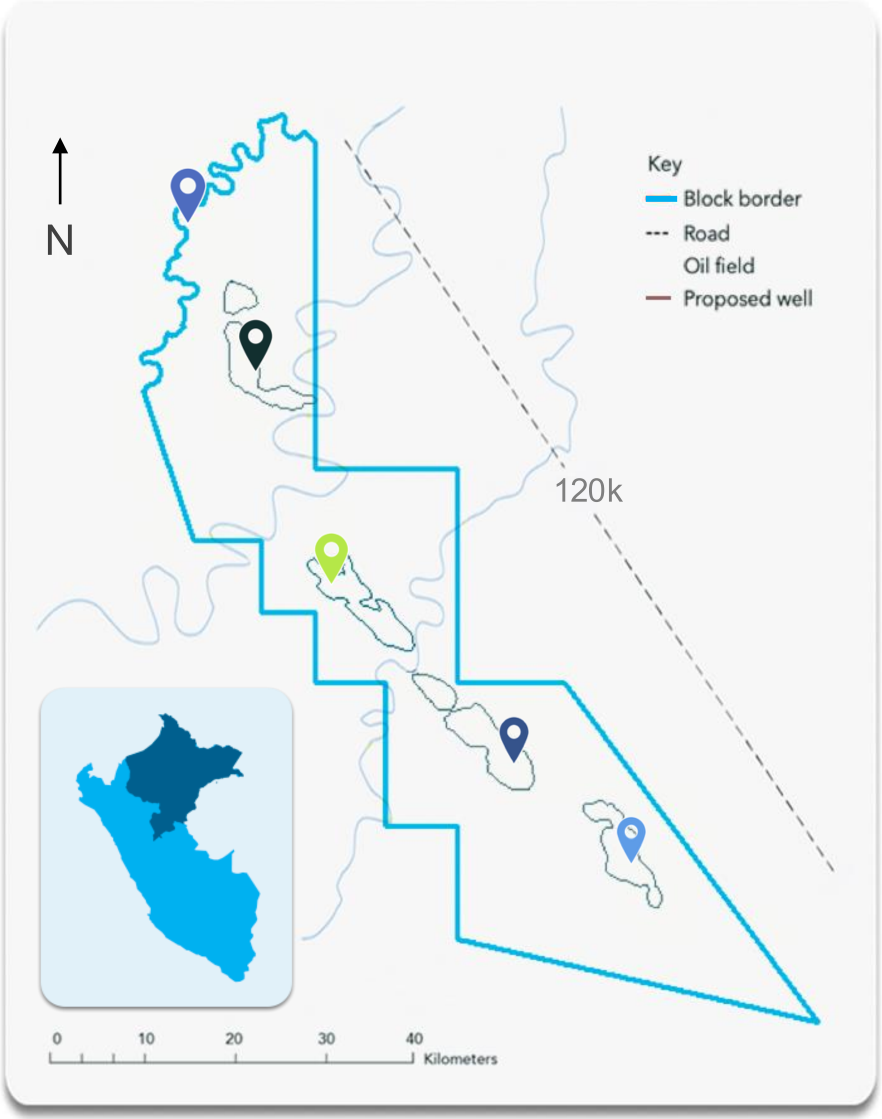
Fiscal Terms

5% - 20% royalty

~7.5% at 20,000 bopd plus 2.5% social fund

License contract until 2041

- Bretaña Field
- Zapote
- Iberia
- Tapiche South
- Lead E



Key highlights

345,000 acres

Large, unexplored area in major producing basin

Existing seismic

Four exploration prospects have been identified on legacy 2D seismic

Drilling potential

PetroTal is considering strategies to de-risk one or two of these prospects

$25-$30M

Estimated D&C capex per well

$10-$12/bbl

Estimated F&D costs if deemed commercial

Expansion

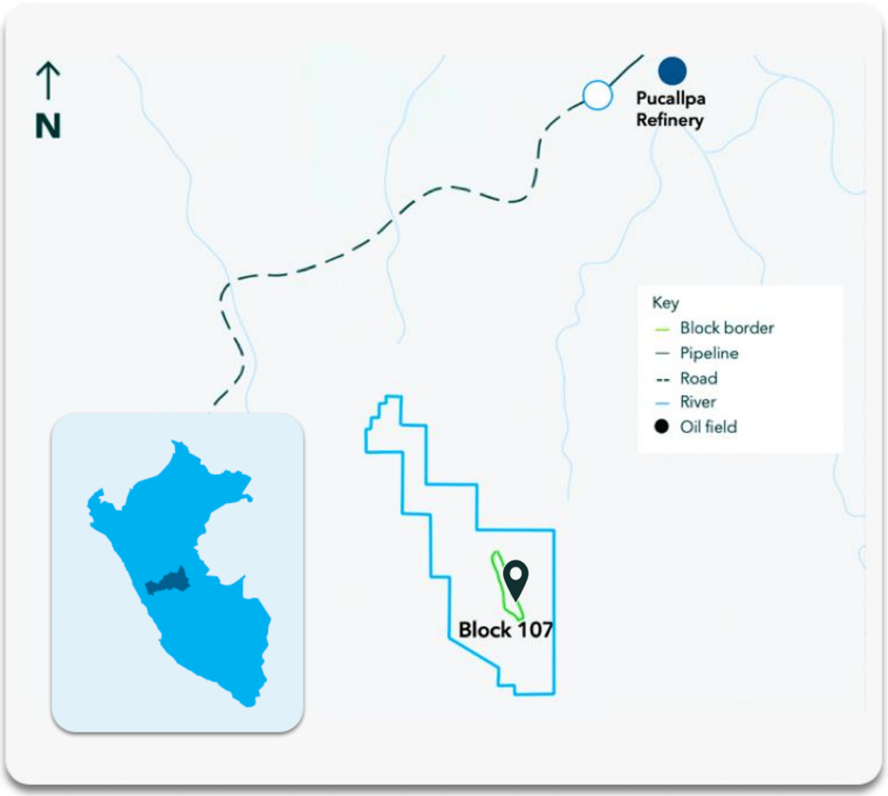
Block 107

Exploration Potential

Fiscal Terms

- Block 107 is a prospect ready area with road access
- Exploration commitment to drill two exploration wells extended to February 2027
- PetroTal will seek a farmout partner
- Gran Tierra retains 20% back in option

Osheki Prospect
Unrisked mean / best estimate
534 / 275 mmbbls prospective resource



Key highlights

534 mmbbls

Mean estimate unrisked prospective resource over an area of 262,000 hectares

Subsurface

Reinterpreted seismic shows two main structural prospects

Updated technical

De-risked with new 3D Geologic Model supporting Cretaceous reservoirs with oil or gas charge from high quality Permian source rocks

Dry hole NPV neutral

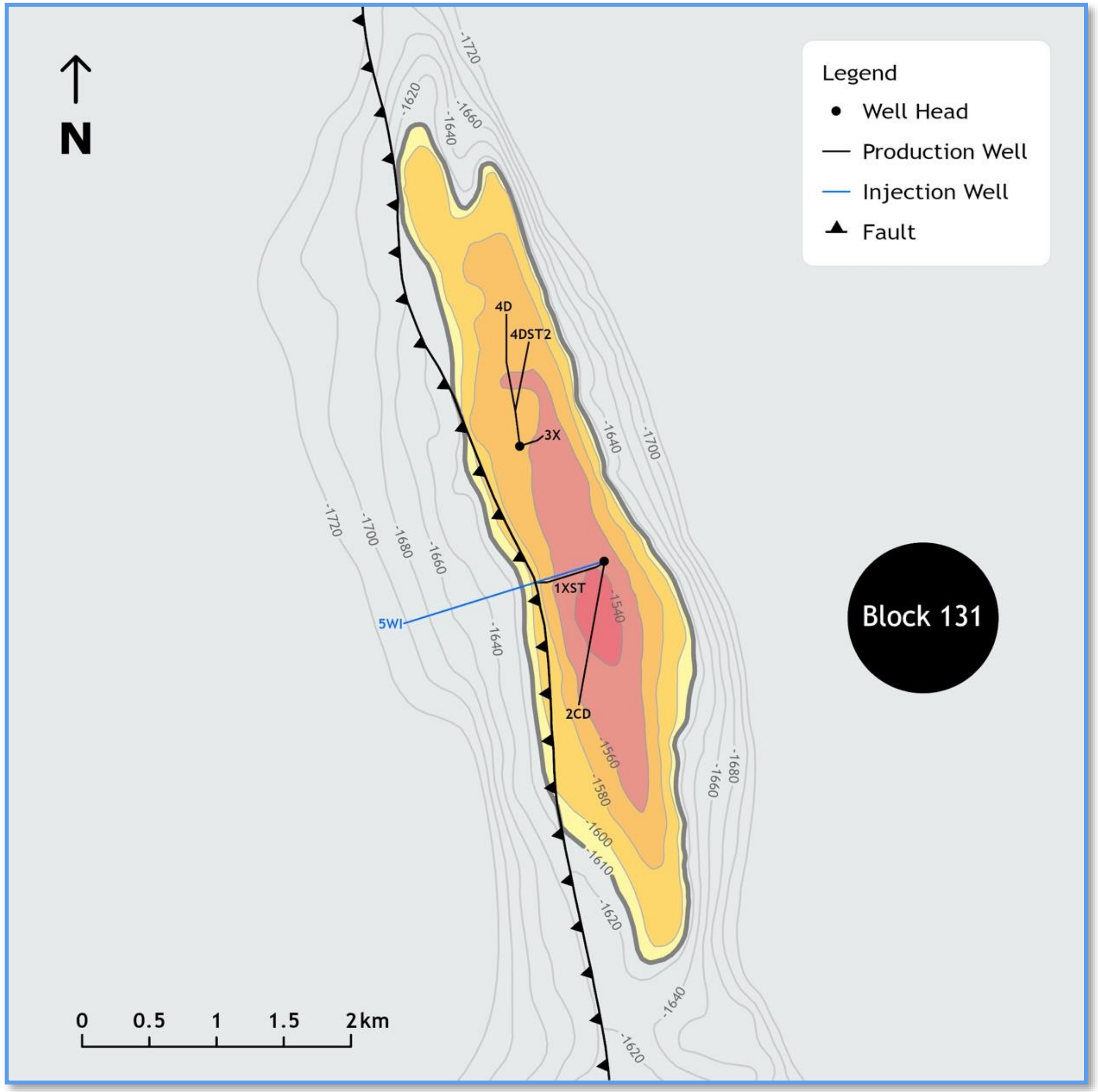
Tax synergies with Bretaña

Block 131

Los Angeles Field

Key highlights

- Acquisition closed in November 2024, for minimal net cash outlay from PetroTal
- Current production is approximately 500 bopd of 40º API oil
- Low risk conventional light oil reservoir in the Cushabatay sand
- Four-way closure composed of fluvial channels of uniform thickness, good porosity / permeability and clear OWC
- Field Size: 2,435 acres



Block 131 cont.

Continued growth in Peru

Development potential

5,500 bopd
Current oil handling capacity

Bypassed oil
Horizontal well locations high on structure

Voidage optimization
Lower opex with less chemical

Blending synergies
At the Iquitos refinery

Upside potential
Previous oil test in deeper Copacabana zone

Fiscal Terms

23.5% base royalty
Royalty on existing production

9.5-20% incremental royalty
New royalty structure for incremental production (pending ratification)

License contract expiring 2037

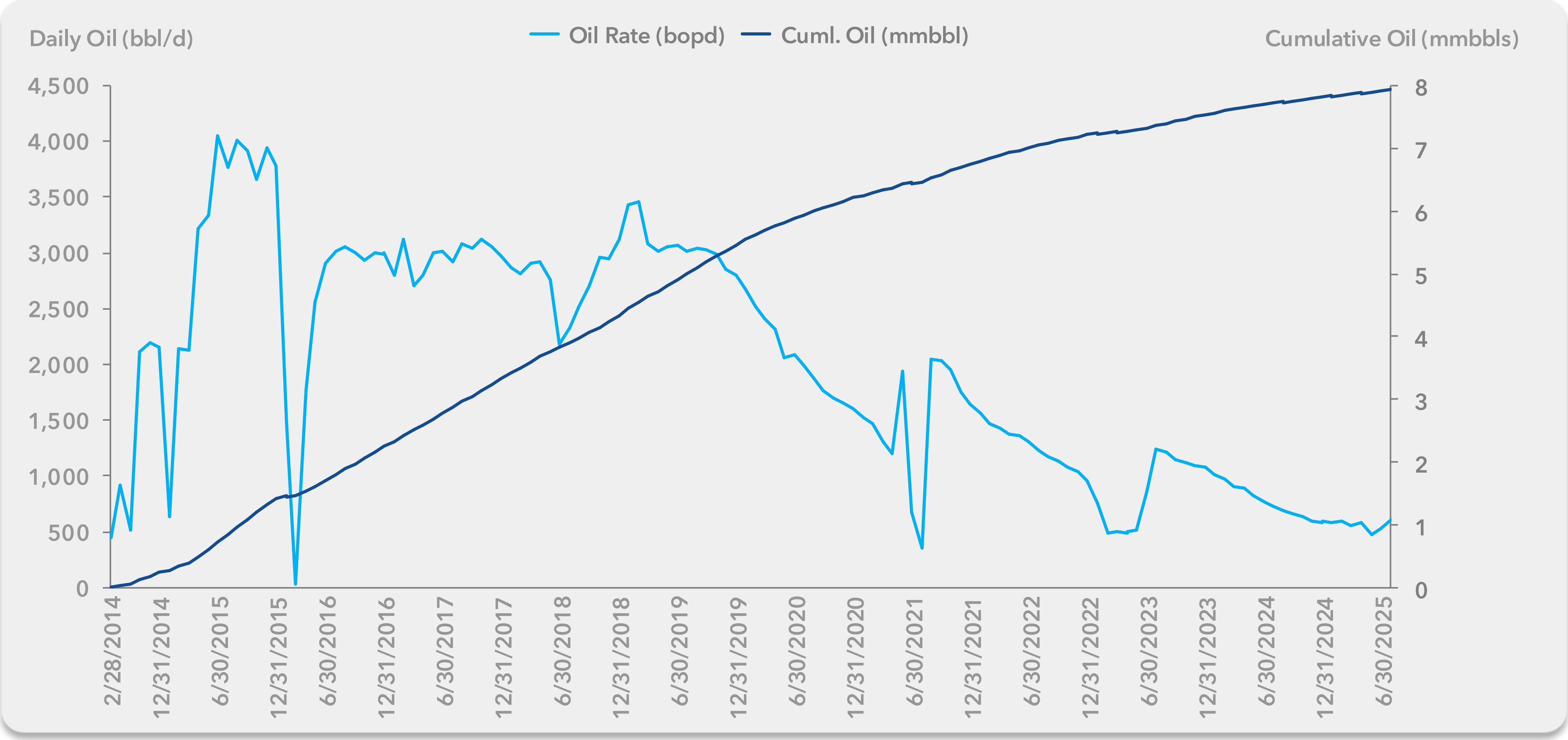
Included infrastructure:

- Oil treatment plant
- Water treatment plant
- Water injection plant

Expansion

Block 131 cont.

Los Angeles field historical production



Expansion

TEA Blocks

Expanding exploration footprint in Ucayali and Maranon Basins

Key highlights

Low-cost land acquisition

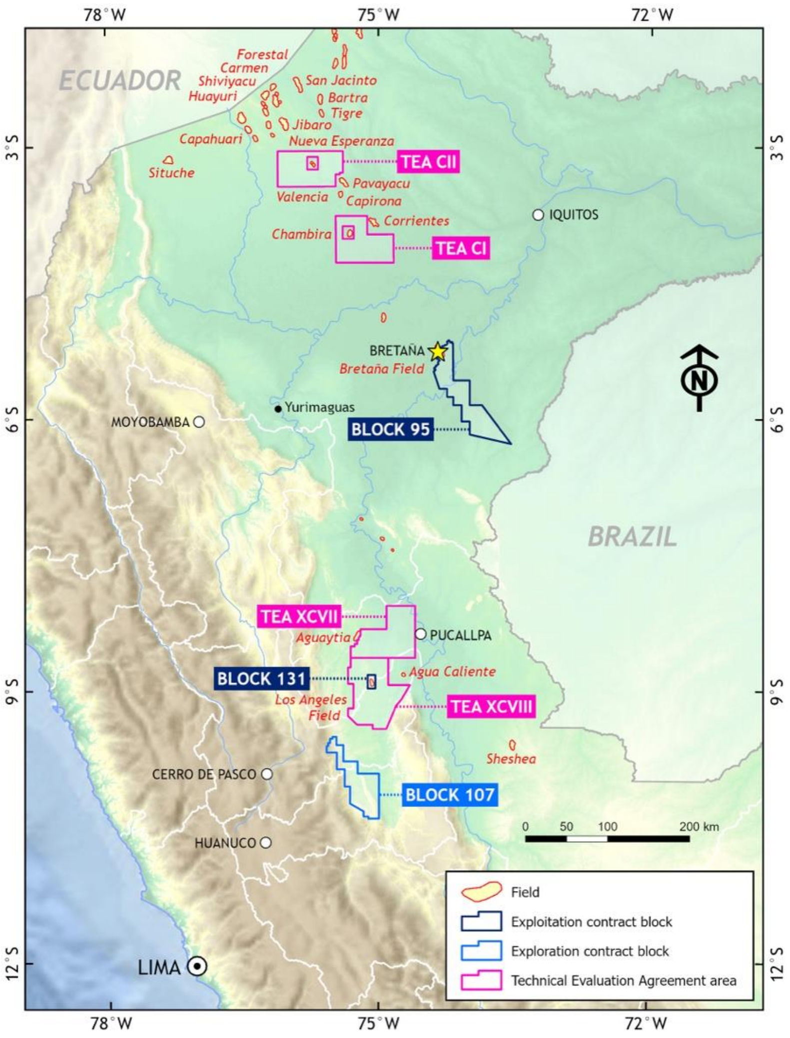
Acreage secured for no up-front capital commitments. TEA's XCVII and XCVIII essentially reconstitute the historical boundaries of present-day Block 131, including acreage that had been relinquished by previous operators. TEA's CI and CII surround producing fields at Lote 8.

Basic work commitments

Work commitments largely include geological and geophysical studies, with total expenditures of approximately $100k per TEA. The TEA contracts grant PetroTal a right of first refusal to convert the acreage to a license contract.

Numerous exploration leads identified

All four TEA's have good legacy seismic coverage, and numerous exploration leads have already been identified on trend with producing oil fields in the area.



2026 financial and operational performance

Key highlights

- Maintain baseline average production above 12,000 bopd
- Capital expenditure budget of $80-90 million
- Begin 8-well drilling program to restore production to 20,000 bopd plateau
- Invest in water handling capacity expansion to 320,000 bwpd by YE28
- Reduce cash opex and G&A expense by 20-25%
- Enhance facility infrastructure at Block 95, in preparation for 2026 development program

2026 guidance summary

Summary in USD millions	2026
	(May 2026 guidance)
Production (bopd)	12,500
Brent ($/bbl)	$83.60
Net operating income	$180
Erosion control (opex portion)	($22)
G&A, Realized Derivative Losses	($41)[1]
EBITDA[2]	$117
Capex	($85)
Accrued tax and finance expense[3]	($24)
After tax free funds flow	$8
Cash Dividends	($0)
2026 YE Cash Balance	~$120 million

(1) Includes mandatory profit sharing for Peru office, and non-cash equity compensation

(2) See footnotes and non Gaap definitions

(3) Amount reflects estimated accrued taxes.

Financial Performance

Cash Flow sensitivity

Illustrative Monthly After-Tax Cash Flow (in $M)

Production (bopd) vs. Brent oil price ($/Bbl)

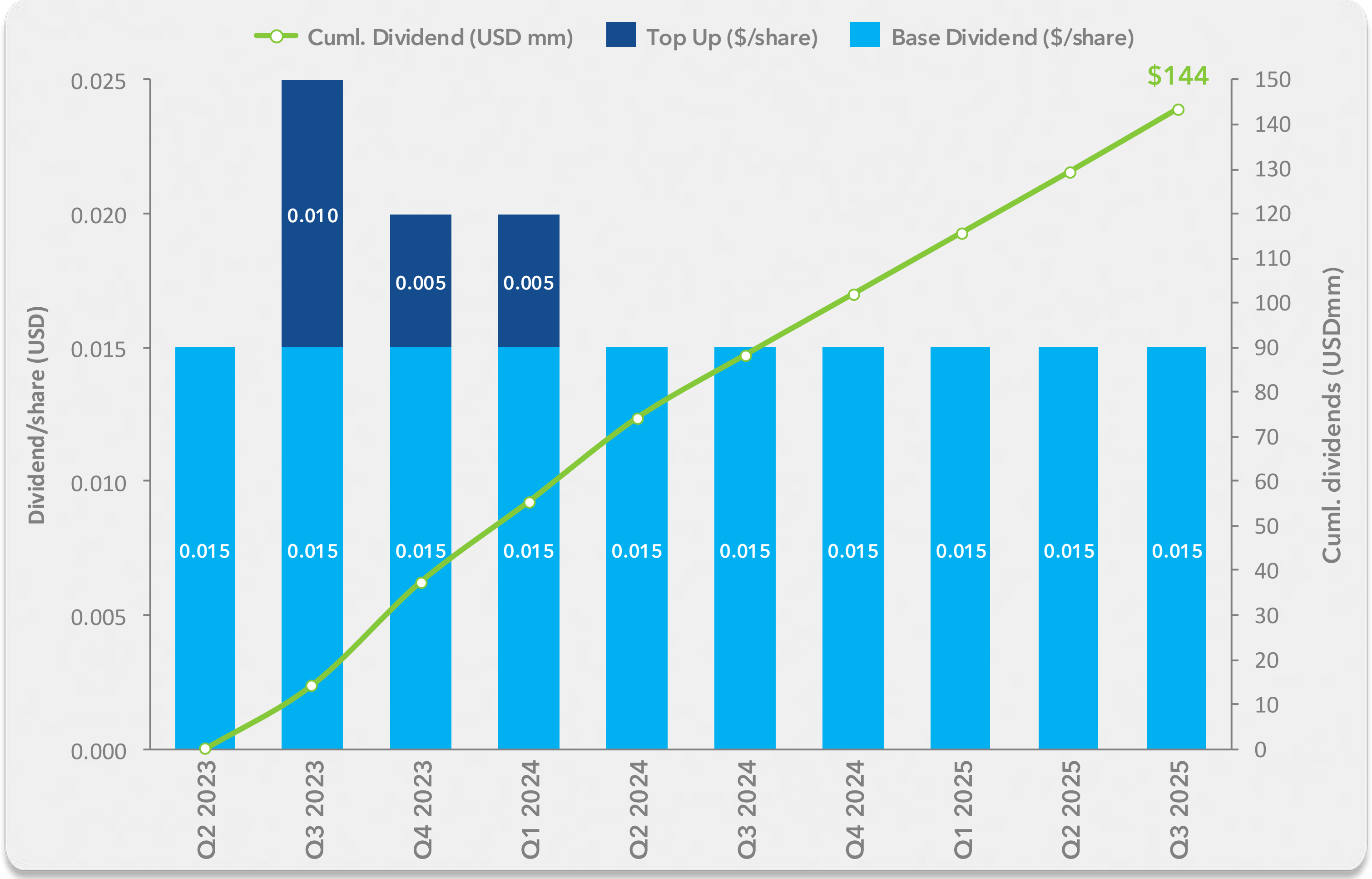
	10,000	11,000	12,000	13,000	14,000	15,000
$100	$9	$10	$12	$13	$15	$17
$90	$7	$8	$10	$11	$12	$13
$80	$5	$6	$8	$9	$10	$11
$70	$2	$3	$4	$5	$7	$8
$60	($1)	($0)	$1	$2	$3	$4

Key assumptions:

- Sensitivity provided for information purposes only – this is not guidance
- Cash Flow figures represent average monthly cash flow over a 12-month period, assuming flat pricing and production
- G&A: $30 million annually
- Erosion Control Opex: $19 million annually
- Cash Tax: range of $6-50 million annually
- Interest/Finance Expense: $11 million annually
- Cash Flow is presented prior to changes in non-cash working capital

Financial Performance

Dividend overview



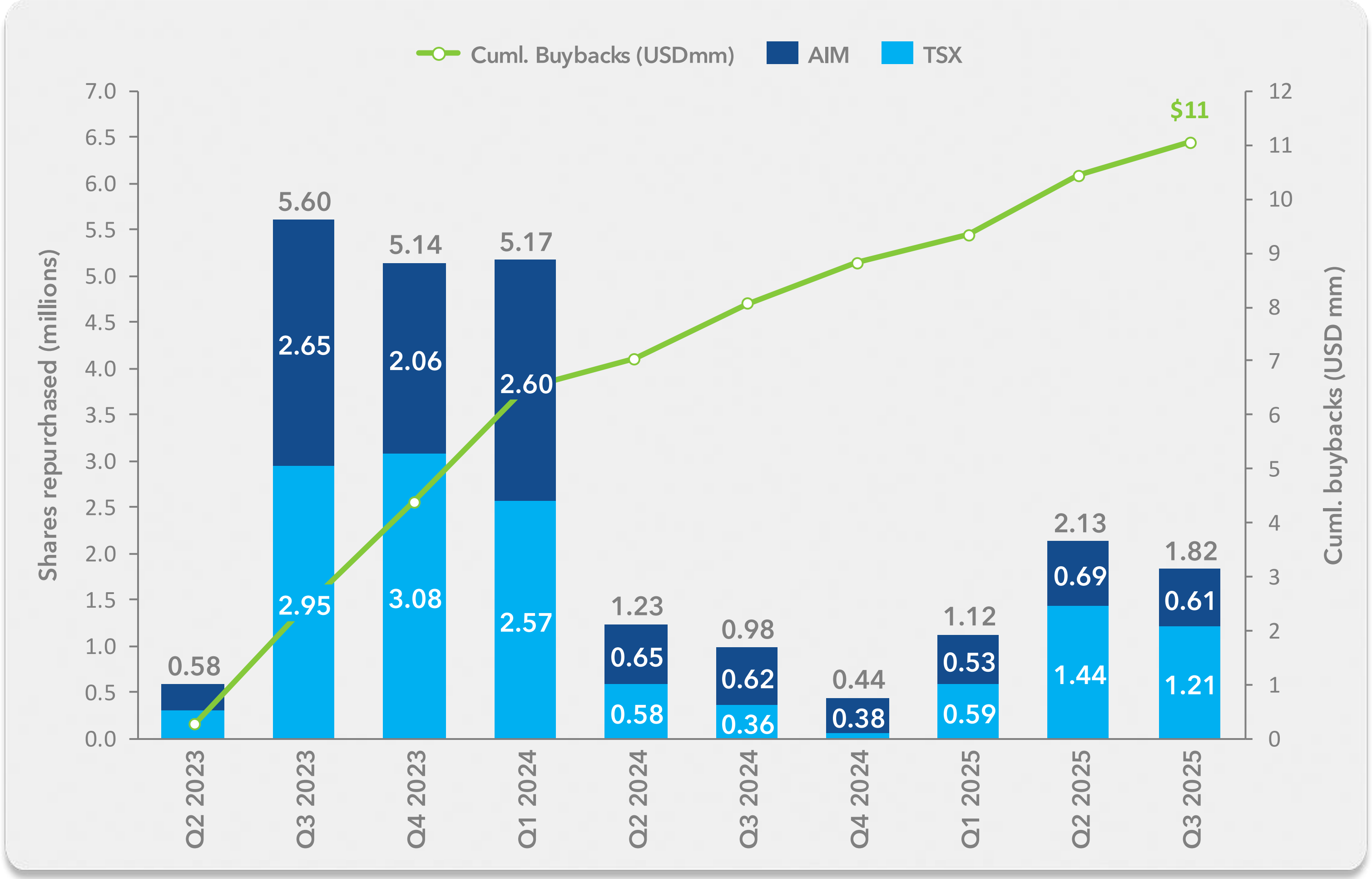
Dividends: $144 million paid ($0.17/share)

Returned through Sept. 15, 2025

- Pay a quarterly $0.015/share base dividend with top up optionality
- Liquidity is cash available at dividend approval date, adjusted by portions of unused credit capacity and or future capital/working capital needs

Financial Performance

Share buyback overview



Buybacks: $11 million in shares purchased

Through September 30, 2025

- Buyback approximately 10% of the Company's public float subject to volume and liquidity constraints
- Target up to $3.0 million in buybacks per quarter

ESG overview

Key Objectives

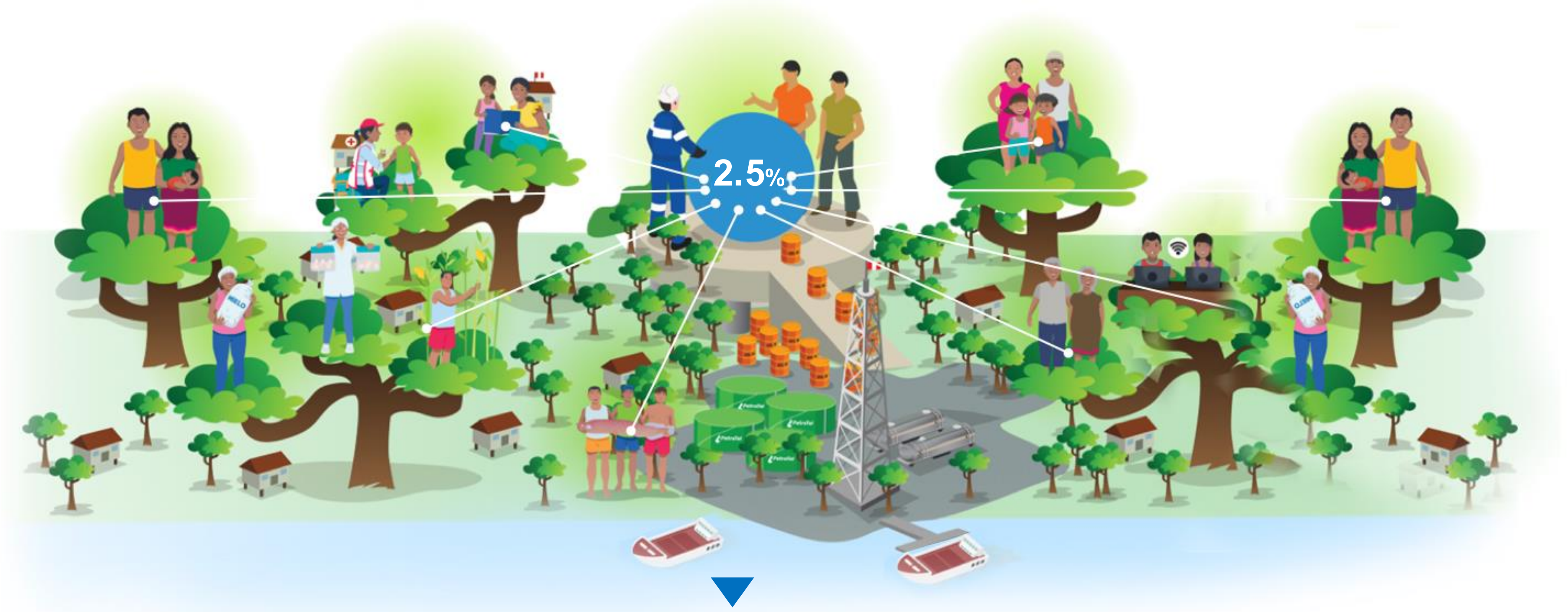
- Alignment with community
- Resource sharing mechanism accelerating the process for benefits
- Fewer operational disruptions, quicker resolutions, and safer work environments
- Management of the social trust by the trust administration committee

PetroTal created social trust

2.5%
Of fiscalized production

~$26 million
Contributions to date[1]

Trust administration committee
(In region, comprised of community members)



Promoting savings for a sustainable fund

1. January 1, 2023 to December 31, 2025

Relevant ESG initiatives

Commitment through policies, projects and programs that have made PetroTal an ESG leader in the Peruvian energy sector

ESG leadership in Perú

Fishing innovation program benefiting ~350 families and resulting in improved product pricing

Communitarian enterprise programs that benefit agri/aquaculture and small animal farming

Solar project aimed at electrifying the Bretaña community with over 3,500 people

Endangered species protection programs for the Taricava (Amazonian Turtle)

Training programs for local women to operate and manage an ice plant to ensure cold fish shipping, resulting in a 15% price increase

Forest restoration initiatives that have restored over seven acres in the *7 de Junio* community


PetroTal
We are energy that generates well-being
Somos energía que genera bienestar

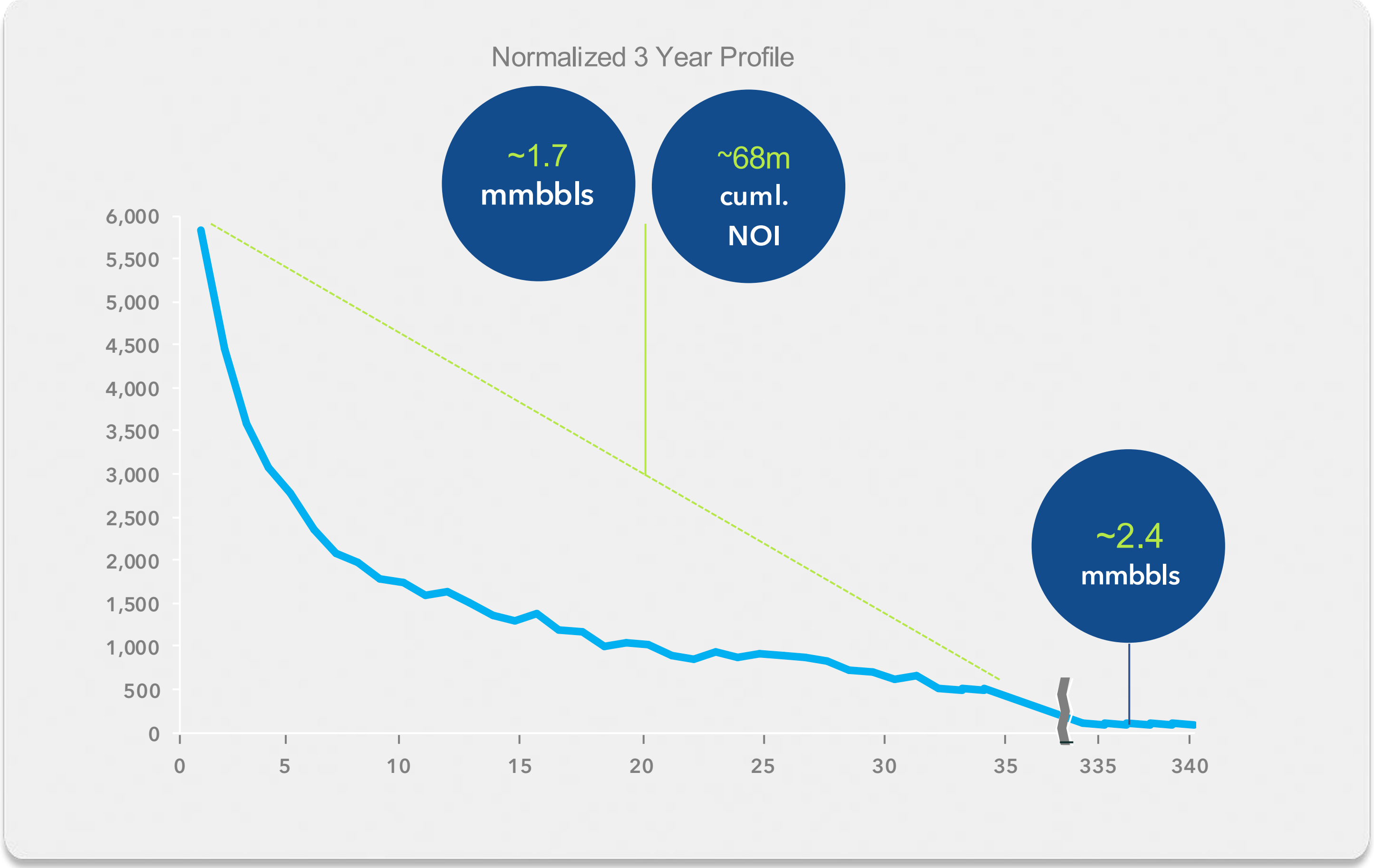
PetroTal

Appendix

Performance

Robust type curve profile

Time Normalized Well Performance (Horizontal Well Portfolio + 7D)



Notes

Actual portfolio average horizontal data would indicate over performance of NSAI 2P type curve. Horizontal portfolio has recycled back its investment 3.7x in ~12 months of normalized production time

Technical team to forecast production using near 2P performance with additional risks applied

Robust economics and payout ratios at current Brent levels to justify continued development of 2P/3P booked locations

Horizontal
(based on actual data)

4,900 bopd
IP 90

3,400 bopd
IP 180

2,600 bopd
IP 365

$11 - $15M
Capex

$4,200
Capital intensity (180 days)

60-120 days
Payout ($65 to $80 Brent)

Estimated 2P Avg
(NSAI)

3,830 bopd
IP 90

3,000 bopd
IP 180

2,290 bopd
IP 365

4.5 mmbbls
EUR

$14M
Capex

$4,667
Capital intensity (180 days)

170-325 days
Payout ($65 to $80 Brent)

>5x
Profit to investment ratio

Deviated
(based on actual data)

2,019 bopd
IP 90

1,652 bopd
IP 180

1,300 bopd
IP 365

$8 - $10m
Capex

$5,400
Capital intensity (180 days)

60 - 120 days
Payout ($65 to $80 Brent)

Appendix cont.

Footnotes

Slide 3
1. Market capitalization as of August 5, 2025
2. Available cash is Q2 2025 actual
3. See disclaimers – Non Gaap financial measures

Slide 4
1. NSAI Reserves statement effective date December 31, 2024
2. Amount invested refers to Capex

Slide 14
1. Per the NSAI Reserves statement effective date 31 December 2024
2. AICD – Autonomous Inflow Control Devices
3. Analogous fields are other heavy oil fields near Block 95

Slide 16
1. Historical reserve replacement ratios are not guaranteed to continue in the future
2. Recovery factors of 26% and 34% are calculated as EUR / original oil in place. (2P = 131 mmbbls / 494 mmbbls) (3P = 229 mmbbls / 658 mmbbls)

Slide 17
1. Per the NSAI Reserves statement effective date 31 December 2024
2. Production profile reflects NSAI's rollup. Management may elect to develop and or pace the asset differently. The production profile should not be interpreted to be the Company's yearly budget.

Slide 18
1. Based on actual company data
2. Payback on each well uses average netback assumptions

Slide 20
1. Water disposal capacities are estimated
2. Construction of additional well cellars is subject to regulatory approval

Slide 21
1. Erosion control allocations and estimates are subject to change

Slide 25
1. Development plans for Block 131, 95 and 107 are all subject to approval by the board of directors and subject to changes and or other approvals by Perupertro and Petroperu

Slides 27
1. Locations and costs are estimated based on internal technical assumptions and are subject to changes

Slide 42
1. First 30 months of type curve based on Company actual data. Remaining type curve depicts an estimated 2P well with 4.5 mmbbls of recoverable oil

Disclaimers

Disclaimer

Reader advisories

FORWARD-LOOKING STATEMENTS: This presentation contains certain statements that may be deemed to be forward-looking statements. Such statements relate to possible future events. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "believe", "expect", "plan", "estimate", "potential", "will", "should", "continue", "may", "objective" and similar expressions. Without limitation, this presentation contains forward-looking statements pertaining to: PetroTal’s intention to continue to develop the Bretana asset; the targeted 24% production growth rate from 2024; PetroTal’s forecast 2025 funds flow; future tax synergies between the Bretana asset and Block 131; PetroTal’s intentions to conduct exploration drilling at Block 95 in 2026; PetroTal’s intentions to continue seeking a partner for co-investment for Block 107 and obtain development permits; the positioning of the Company in 2025; PetroTal’s intentions with respect to its return of capital program (including that the program will continue to consist of dividends at $0.015/share and target buybacks up to $1.0 million/quarter in accordance with the Company’s return of capital policy); PetroTal’s plans to commercialize new sales routes through the OCP in Ecuador and through Yurimaguas to Bayovar and the anticipated benefits therefrom (including in respect of production estimates) and the timing thereof; PetroTal's expectations with respect to projects and key initiatives to be financed with contributions from the Social Trust Fund; estimated returns from the Company’s 2025 dividend and buyback plan; drilling plans including with respect to the commencement and completion of drilling wells; estimated payback from wells and the timing thereof; PetroTal’s plans to continue to allocate capital to its long term preventative erosion control program; PetroTal’s 2025 budget for the erosion control project and plans in respect thereof; the 2025 Capex budget; and PetroTal’s expectations regarding 2025 operating costs.

In addition, statements relating to expected production, reserves, recovery, replacement, costs and valuation are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. The forward-looking statements are based on certain key expectations and assumptions made by the Company, including, but not limited to, expectations and assumptions concerning the ability of existing infrastructure to deliver production and the anticipated capital expenditures associated therewith, the ability to obtain and maintain necessary permits and licenses, the ability of government groups to effectively achieve objectives in respect of reducing social conflict and collaborating towards continued investment in the energy sector, reservoir characteristics, recovery factor, exploration upside, prevailing commodity prices and the actual prices received for PetroTal's products, including pursuant to hedging arrangements, the availability and performance of drilling rigs, facilities, pipelines, other oilfield services and skilled labour, royalty regimes and exchange rates, the impact of inflation on costs, the application of regulatory and licensing requirements, the accuracy of PetroTal's geological interpretation of its drilling and land opportunities, current legislation, receipt of required regulatory approval, the success of future drilling and development activities, the performance of new wells, future river water levels, the Company's growth strategy, general economic conditions and availability of required equipment and services. PetroTal cautions that forward-looking statements relating to PetroTal are subject to all of the risks, uncertainties and other factors, which may cause the actual results, performance, capital expenditures or achievements of the Company to differ materially from anticipated future results, performance, capital expenditures or achievement

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expressed or implied by such forward-looking statements. Factors that could cause actual results to differ materially from those set forth in the forward-looking statements include, but are not limited to, risks associated with the oil and gas industry in general (e.g., 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), business performance, legal and legislative developments including changes in tax laws and legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures, credit ratings and risks, fluctuations in interest rates and currency values, changes in the financial landscape both domestically and abroad, including volatility in the stock market and financial system, wars (including Russia's war in Ukraine and the Israeli-Hamas conflict), regulatory developments, commodity price volatility, price differentials and the actual prices received for products, exchange rate fluctuations, legal, political and economic instability in Peru, access to transportation routes and markets for the Company's production, changes in legislation affecting the oil and gas industry; changes in the financial landscape both domestically and abroad (including volatility in the stock market and financial system) and the occurrence of weather-related and other natural catastrophes. Readers are cautioned that the foregoing list of factors is not exhaustive. Please refer to the risk factors identified in the Company's most recent annual information form and management's discussion and analysis (the "MD&A") which which can be accessed either on PetroTal's website at www.petrotal-corp.com or on SEDAR+ at www.sedarplus.ca. The forward-looking statements contained in this press release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. Forward looking CAPEX and OPEX assumptions in this presentation are consistent with the NSAI Reserve Report as of Dec 31, 2023 and current historical operating results to date, however, the timing and pace of the development plan has been adjusted from the NSAI Report to align with management's internal view on commodity price and liquidity. Management may create and post alternative development cases at their discretion and label them internal.

FOFI DISCLOSURE: This presentation contains future-oriented financial information and financial outlook information (collectively, "FOFI") about PetroTal's prospective results of operations, and production results, 2024 drilling program and budget, well investment payback, cash position, liquidity and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this presentation was approved by management as of the date of this presentation and was included for the purpose of providing further information about PetroTal's anticipated future business operations. PetroTal and its management believe that FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. PetroTal disclaims any intention or obligation to update or revise any FOFI contained in this presentation, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this presentation should not be used for purposes other than for which it is disclosed herein. All FOFI contained in this presentation complies with the requirements of Canadian securities legislation, including NI 51-101.

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Changes in forecast commodity prices, differences in the timing of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in PetroTal's guidance. The Company's actual results may differ materially from these estimates.

SPECIFIED FINANCIAL MEASURES, OIL AND GAS METRICS AND OTHER KEY PERFORMANCE INDICATORS: This presentation includes various specified financial measures, including non-GAAP financial measures, non-GAAP financial ratios and capital management measures such as “Netback”, “EBITDA”, “Adjusted EBITDA”, “Net Operating Income” and “free funds flow”. These measures do not have a standardized meaning prescribed by generally accepted accounting principles (“GAAP”) and, therefore, may not be comparable with the calculation of similar measures. In addition, this presentation contains metrics commonly used in the oil and natural gas industry and other key performance indicators, financial and non-financial, that do not have standardized meanings under the applicable securities legislation. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures. “Netback” (non-GAAP financial measure) equals total petroleum sales less quality discount, lifting costs, transportation costs and royalty payments calculated on a bbl basis. The Company considers netbacks to be a key measure as they demonstrate Company’s profitability relative to current commodity prices. “EBITDA” (non-GAAP financial measure) is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization and adjusted for G&A impacts and certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses, including derivative true-up settlements.

PetroTal utilizes EBITDA as a measure of operational performance and cash flow generating capability. EBITDA impacts the level and extent of funding for capital projects investments. “Adjusted EBITDA” (non-GAAP financial measure) is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization and adjusted for G&A impacts and certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses, including derivative true-up settlements. PetroTal utilizes adjusted EBITDA as a measure of operational performance and cash flow generating capability. Adjusted EBITDA impacts the level and extent of funding for capital projects investments. Reference to EBITDA is calculated as net operating income less G&A. “Net Operating Income” (non-GAAP financial measure) is calculated as revenues less royalties, operating expenses, and direct transportation. The Company considers Net Operating Income measure as they demonstrate Company’s profitability relative to current commodity prices. “Free funds flow” (non-GAAP financial measure) is calculated as net operating income less G&A less exploration and development capital expenditures less realized derivative gains/losses and is calculated prior to all debt service, taxes, lease payments, hedge costs, factoring, and lease payments. Management uses free funds flow to determine the amount of funds available to the Company for future capital allocation decisions. “NPV-10” or similar expressions represents the net present value (net of capex) of net income discounted at 10%, with net income reflecting the indicated oil, liquids and natural gas prices and IP rate, less internal estimates of operating costs and royalties. “Enterprise value” is calculated as the market capitalization of the Company plus net debt, where market capitalization is defined as the total number of shares outstanding multiplied by the price per share at a given point in time. “CAPEX” means capital expenditures. “IP” means the initial production from a well for a set unit of time. “Capital efficiency” is CAPEX divided by production rate (bopd). “EUR” means estimated ultimate.

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recovery, an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well. EUR is not a defined term within the COGE Handbook and therefore any reference to EUR in this presentation is not deemed to be reported under the requirements of NI 51-101. Readers are cautioned that there is no certainty that the Company will ultimately recover the estimated quantity of oil or gas from such reserves or wells. "F&D" means finding and development costs, calculated as the sum of capital expenditures incurred in the period and the change in FDC required to develop reserves. "Free cash" or "free funds flow" defined as Adjusted EBITDA before minus CAPEX. "Yield" means free funds flow per year as a percentage of market capitalization. Please refer to the MD&A for additional information relating to specified financial measures.

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RESERVES DISCLOSURE. The reserve estimates contained herein were derived from a reserves assessment and evaluation prepared by Netherland Sewell & Associates, Inc. ("NSAI"), a qualified independent reserves evaluator, with an effective date of December 31, 2023 (the "NSAI Reserves Report"). The NSAI Reserves Report has been prepared in accordance with definitions, standards and procedures contained in NI 51-101 and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"). The reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Volumes of reserves have been presented based on a company interest. Readers should give attention to the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each category as explained herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

RESOURCES DISCLOSURE. The prospective resource estimates contained herein were derived from a resource assessment and evaluation prepared by NSAI, a qualified independent reserves evaluator, with an effective date of June 30, 2020 (the "NSAI Resources Report"). The NSAI Resources Report has been prepared in accordance with definitions, standards and procedures contained in NI 51-101 and the COGE Handbook. Prospective resources are the quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. All of the prospective resources have been classified as light oil with a gravity of 46 degrees API. There is uncertainty that it will be commercially viable to produce any portion of the resources in the event that it is discovered. "Unrisked Prospective Resources" are 100% of the volumes estimated to be recoverable from the field in the event that it is discovered and developed. NSAI has determined that a 16% chance of discovery is appropriate for the prospective resources based on an assessment of a number of criteria. The estimates of prospective resources provided in this presentation are estimates only and there is no guarantee that the estimated prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated. Not only are such prospective resources estimates based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Prospective resources should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates herein. The prospective resources estimates that are referred to herein are risked

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as to chance of discovery. Risks that could impact the chance of discovery include, without limitation, geological uncertainty, political and social issues, and availability of capital. In general, the significant factors that may change the prospective resources estimates include further delineation drilling, which could change the estimates either positively or negatively, future technology improvements, which would positively affect the estimates, and additional processing capacity that could affect the volumes recoverable or type of production. Additional facility design work, development plans, reservoir studies and delineation drilling is expected to be completed by PetroTal in accordance with its long-term resource development plan.

RESERVE CATEGORIES. Reserves are classified according to the degree of certainty associated with the estimates. Proved reserves (1P) 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 (2P) 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. Possible reserves (3P) are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
RESOURCE CATEGORIES. Prospective resources are classified according to the degree of certainty associated with the estimates. The following classification of prospective resources used in the presentation: Low Estimate (or 1C) means there is at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate. Best Estimate (or 2C) means there is at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate. High Estimate (or 3C) means there is at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate. MEAN ESTIMATE. Represents the arithmetic average of the expected recoverable volume. It is the most accurate single point representation of the volume distribution.
BOE DISCLOSURE. The term barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel (6Mcf/bbl) of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All BOE conversions in the report are derived from converting gas to oil in the ratio mix of six thousand cubic feet of gas to one barrel of oil.
OIL REFERENCES: All references to "oil" or "crude oil" production, revenue or sales in this press release mean "heavy crude oil" as defined in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). All references to "light oil" production, revenue or sales mean "light crude oil" as defined in NI 51-101. Brent refers to Intercontinental Exchange "ICE" Brent.
ANALOGOUS INFORMATION. Certain information in this document may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to areas, wells and/or operations that are in geographical proximity to or on-trend with lands held by PetroTal and production information related to wells that are believed to be on trend with PetroTal's properties. Such information has been obtained from government sources, regulatory agencies or other industry participants. Management of PetroTal believes the information may be relevant to help define the reservoir characteristics in which PetroTal may hold an interest and such information has been presented to help demonstrate the basis for PetroTal's business plans and strategies.

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However, PetroTal has no way of verifying the accuracy of such information. There is no certainty that the results of the analogous information or inferred thereby will be achieved by PetroTal and such information should not be construed as an estimate of future production levels. Such information is also not an estimate of the reserves or resources attributable to lands held or to be held by PetroTal and there is no certainty that the reservoir data and economics information for the lands held or to be held by PetroTal will be similar to the information presented herein. The reader is cautioned that the data relied upon by PetroTal may be in error and/or may not be analogous to such lands to be held by PetroTal.

SHORT TERM RESULTS: References in this presentation to peak rates, initial production rates, current production rates, initial 14-day production rates, IP 90, IP 180, IP 365, test rates, flow rates, initial and/or final raw test or production rates, early production, test volumes and/or "flush" production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. Such rates may also include recovered "load" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of PetroTal. The Company cautions that such results should be considered to be preliminary.

TYPE CURVES. Certain type curves disclosure presented herein represent estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. The type curves represent what management thinks an average well will achieve. Individual wells may be higher or lower but over a larger number of wells, management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells.

OOIP DISCLOSURE. The term original-oil-in-place ("OOIP") is equivalent to total petroleum initially-in-place ("TPIIP"). TPIIP, as defined in the COGE Handbook, is that quantity of petroleum that is estimated to exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. A portion of the TPIIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the TPIIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of TPIIP will never be recovered.

US DISCLAIMER. This presentation is not an offer of the securities for sale in the United States. The securities have not been registered under the U.S. Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an exemption from registration. This presentation shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the securities in any state in which such offer, solicitation or sale would be unlawful.

All figures in US dollars unless otherwise denoted.

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Abbreviations

Bbl
Barrel

Bopd
Barrel of oil per day

k bopd / Thousand barrel of oil per day

F&D
Finding and development cost

NIBD
Net interest-bearing debt

Mmbbl
Million barrels of oil

NGL
Natural gas liquids

Bbo
Billion barrels of oil

API
an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil

Free Funds/ Cash Flow
Adjusted EBITDA less CAPEX or as defined in footnotes

FFO
Funds flow from operations

Adj. EBITDA
Earnings before interest, taxes, depreciation, amortization, and after realized derivative adjustments; EBITDA is Adj. EBITDA prior to derivative impacts

3P
Proved + Probable + Possible Reserves

Adjusted free funds flow
Free funds flow adjusted by changes in non cash working capital

Normalized EBITDA
EBITDA excluding material one time non-recurring expenses

Ha
Hectares

PDP
Proved Developed Producing Reserves

1P
Proved Reserves

2P
Proved + Probable Reserves

3P
Proved + Probable + Possible Reserves

Net surplus
Net Surplus (Debt) = Total cash + all trade and net VAT receivables + short and long term net derivative balances – total current liabilities – long term debt – non current lease liabilities – net deferred tax – other long term obligations.
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PetroTal