Investor Presentation

Enercom Dallas April 18 2023

PetroTal introduction video – company overview

Disclaimers

PetroTal Institutional Video (2-3 mins)

https://www.youtube.com/watch?v=vGqRG8wU1Q8

PetroTal introduction video - biodiversity

PetroTal Biodiversity Monitoring Video (2-3 mins)
https://www.youtube.com/watch?v=HDGYKKod5OM

PetroTal overview

PetroTal

Corporate and technical summary

Corporate summary

Trading price	April 11 2023	$0.76 CAD
Basic shares	Millions	884
Market cap		$500
Net debt/(Surplus) (Q4 2022)	USD millions	($74)
Enterprise value	""	$426
EV/2023 EBITDA		1.9x
2023 Production guidance	bopd	14,000 – 15,000
Corporate derivatives (Jan – Sept 2023)	$80/bbl floor	0.4 mmbbls
Embedded derivatives (ONP)	$55 to $85/bbl ACB	2.4 mmbbls

Technical summary

Current production (April to date 2023)	bopd	~20,000
2P reserves	mmbbl	97
Producing well count	Incl. 14H	15
Oil processing capacity	bopd	26,000
Iquitos sales capacity	bopd	1,300 – 2,000
Brazil sales capacity	bopd	14,000 – 18,000
ONP sales capacity	bopd	0 – 25,000

Asset location and key landmarks

See footnotes in March 2023 Presentation on website

Company value proposition

PetroTal

Development running room

Can deliver material production growth and free funds flow yield

Strong capital efficiency metrics

Outstanding technical performance

Waterflood pressure support

(naturally occurring)

Robust heavy oil EBITDA margins

ESG leadership in Peru

Small field footprint (<30 acres)
11.4 kg/bbl in scope 1 emissions in 2021
Zero spills and volume discharge in 2021

See footnotes in March 2023 Presentation on website

Company history

PetroTal

2017/2018	2019	2020	2021	2022	2023
0/958 bopd (greenfield)	4,131 bopd 330% growth	5,675 bopd 37% growth	8,956 bopd 58% growth	12,200 bopd 36% growth *Generated a 4.9x return on Q3 2022 book equity of $130 million (all time share price high)*	14,000 to 15,000 bopd 19% growth

Invested An estimated $331 million of capex invested (26,000 bopd oil capacity)

Produced ~12.0 million barrels produced (inception – 2022)

Generated ~$400 million EBITDA generated since inception (estimated)

Commercialized Established 3rd sales route (Brazil) up to 18,000 bopd

Enabled Production of 22,000 bopd (unconstrained)

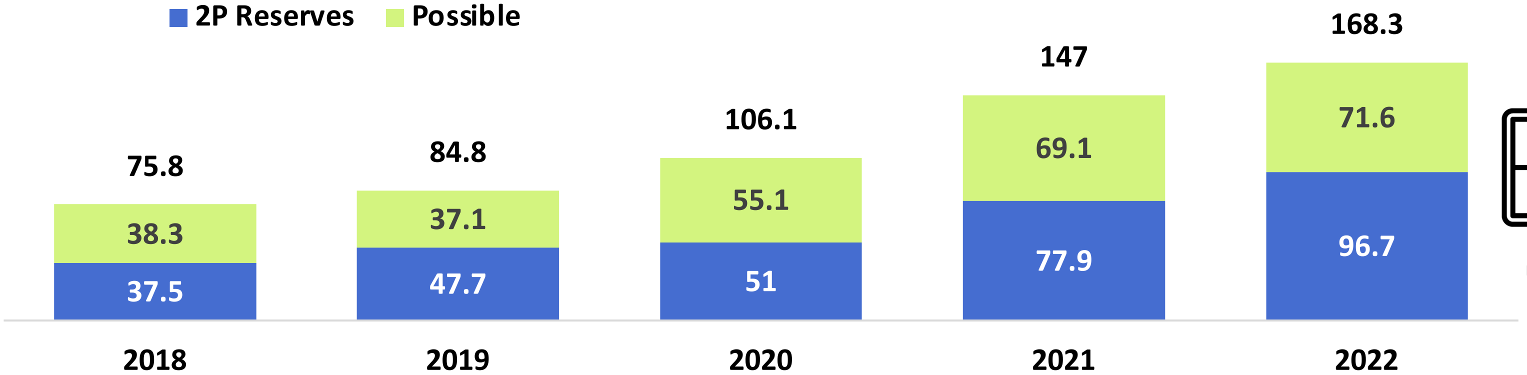
Returns Started dividends and buyback programs (target min liquidity of $50 million)

See footnotes in March 2023 Presentation on website

Bretaña reserves summary

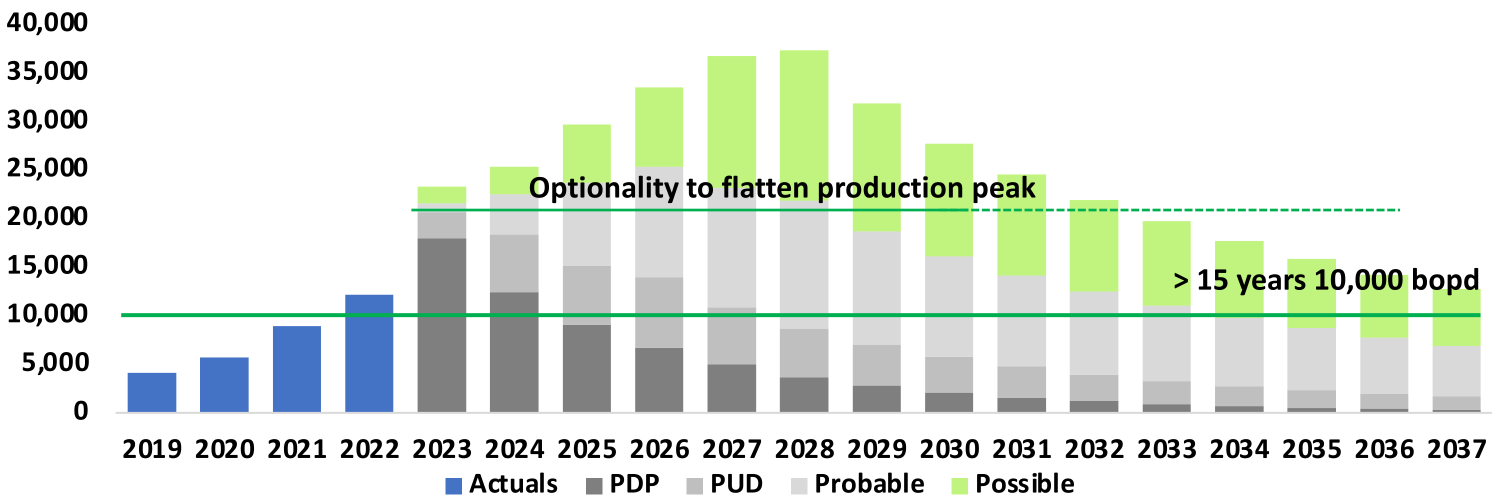
PetroTal

Reserves summary (mmbbl)



- 2P and 3P **recovery factors of 24% and 28%,** delivered in four years from zero production
- Booked 2P well count at **29 wells** allowing continuous multi year development programs
- 2022 **2P EUR (ultimate recovery) now over 100 mmbbls**

Netherland Sewell ("NSAI") production profile (bopd)



- **~15 years of production > 10,000** bopd under 3P case
- Peak production **of 37,000 bopd** plausible
- Ability to flatten peak production into **multi year production profile** of 20,000 to 25,000 bopd

Key reserve metrics (USD millions)

Case	OOIP mmbbl	Reserves mmbbl	Recovery Factor	A-tax NPV(10)	F&D USD millions	F&D/bbl	Recycle Ratio ($45/bbl netback)
1P	329	46	17%	$784 ($0.9/share)	$229	$4.9	9x
2P	445	97	24%	$1,509 ($1.75/share)	$404	$4.2	11x
3P	632	168	28%	$2,468 ($2.86/share)	$624	$3.7	12x

- **All categories of F&D/bbl < $5.0/bbl** generating a recycle ratio of 9-12x at $85/bbl Brent
- **Billion dollar 2P** after tax valuation
- **Fundable 3P program** out of existing cash flow

See footnotes in March 2023 Presentation on website

2023 financial and operational guidance

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Summary in USD millions	2020	2021	2022	2023
	actual	*actual*	***Actual***	***Budget (Feb 2023)***
Production (bopd)	**5,674**	**8,965**	**12,200**	**~14,000 - 15,000**
Brent ($/bbl)	$42	$71	$99	~$85
Net operating income	**$29**	**$105**	**$274**	**$256**
G&A	($11)	($14)	($20)	($34)[1]
Net derivative impact/other	$5	$11	$2	($2)
Pre Tax Adjusted EBITDA	**$23**	**$102**	**$256**	**$220**
Capex	($42)	($82)	($94)	($125)
Accrued tax[2]				**($40)**
Free funds flow **(pre debt service)[2]**	**($19)**	**$20**	**$162**	**$55**
Net debt (surplus)	**32**	**55**	**(74)**	**N/A**

[1] Includes $7.2 million in social and community related G&A costs

[2] Tax planning in Feb/Mar 2023 may confirm higher NOLs and a lower tax burden by up to $20 million in budget base case

2023 after tax free funds flow matrix (USD millions)

Yearly sales (bopd) →

Contracted average Brent USD/bbl ↓

	10,500	12,500	14,500	16,500	18,500
$110	**$66**	**$100**	**$133**	**$166**	**$197**
$105	**$55**	**$86**	**$118**	**$148**	**$177**
$100	**$44**	**$73**	**$102**	**$131**	**$158**
$95	**$33**	**$60**	**$87**	**$113**	**$139**
$90	**$21**	**$46**	**$71**	**$96**	**$119**
$85	**$10**	**$33**	**$55**	**$78**	**$100**
$80	**($1)**	**$20**	**$40**	**$61**	**$80**
$75	**($12)**	**$6**	**$25**	**$43**	**$61**
$70	**($23)**	**($8)**	**$9**	**$25**	**$41**

In 2023 PetroTal can defer up to $40 million of capex in these scenarios

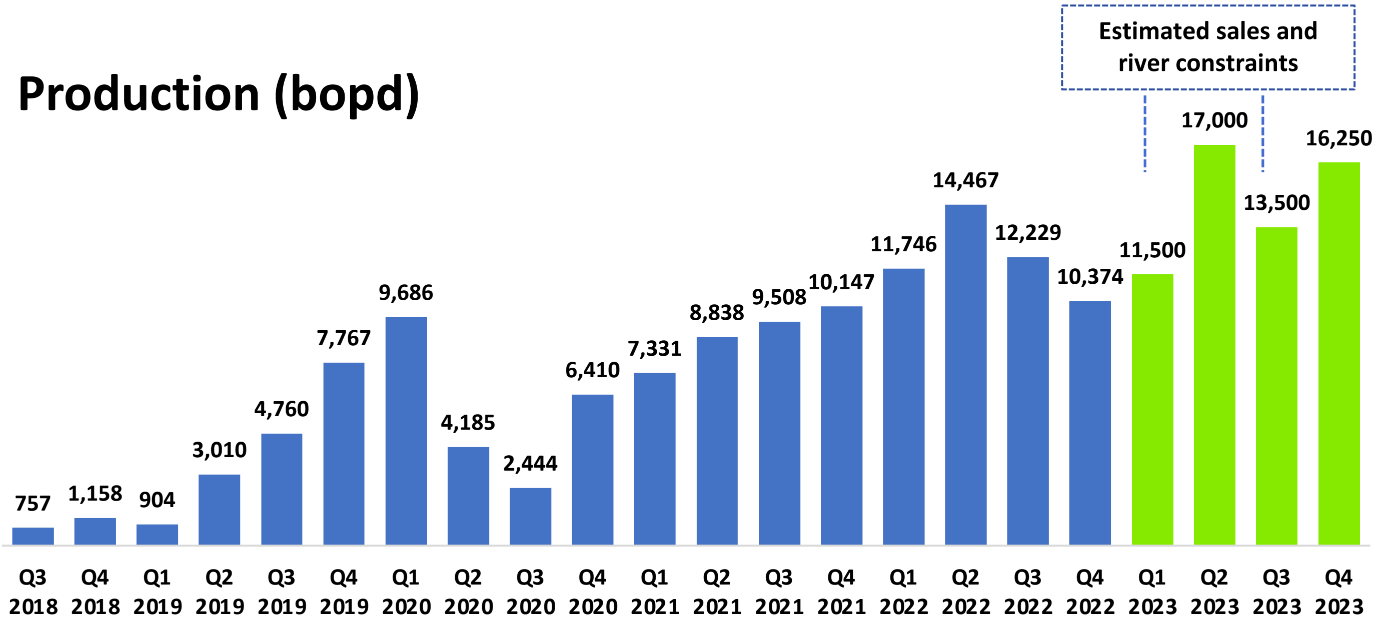
Post development, maintenance Capex is $25 million per year

Matrix assumes a $125 million Capex program, 5% employee tax, corporate tax, and 2.5% social trust royalty

Free cash flow matrix notes:

- *Assumes a base run rate G&A range of approximately $27 million plus $7 million of social and community related G&A costs*
- *Assumes an estimated $40 million in corporate tax and use of all loss carry forwards*
- *Also assumes no derivative true up impacts or deductible interest expenses*

Production (bopd)



See footnotes in March 2023 Presentation on website

2023 budget highlights

- Average 2023 production of **~14,500 bopd (midpoint)** assuming no ONP sales
- Adj. EBITDA **at ~ $220 million**
- **$125 million of 2022 CAPEX includes:**
  - Three new wells on production and one additional water disposal well **($69 million)**
  - L2 West platform **($11 million)**
  - Erosion mitigation **($9 million)**
  - Additional production and water handling equipment **($36 million)**

PetroTal led solution to social equality

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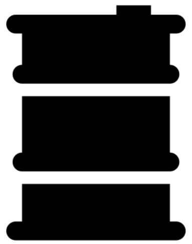
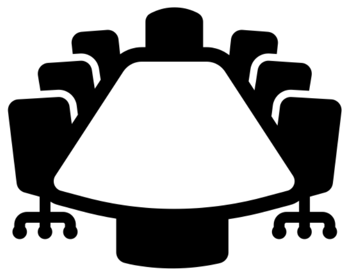


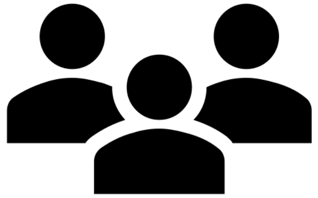
- 2.5% of fiscalized production
- Part of working table
- Communication hub for all parties



Third party trust directors

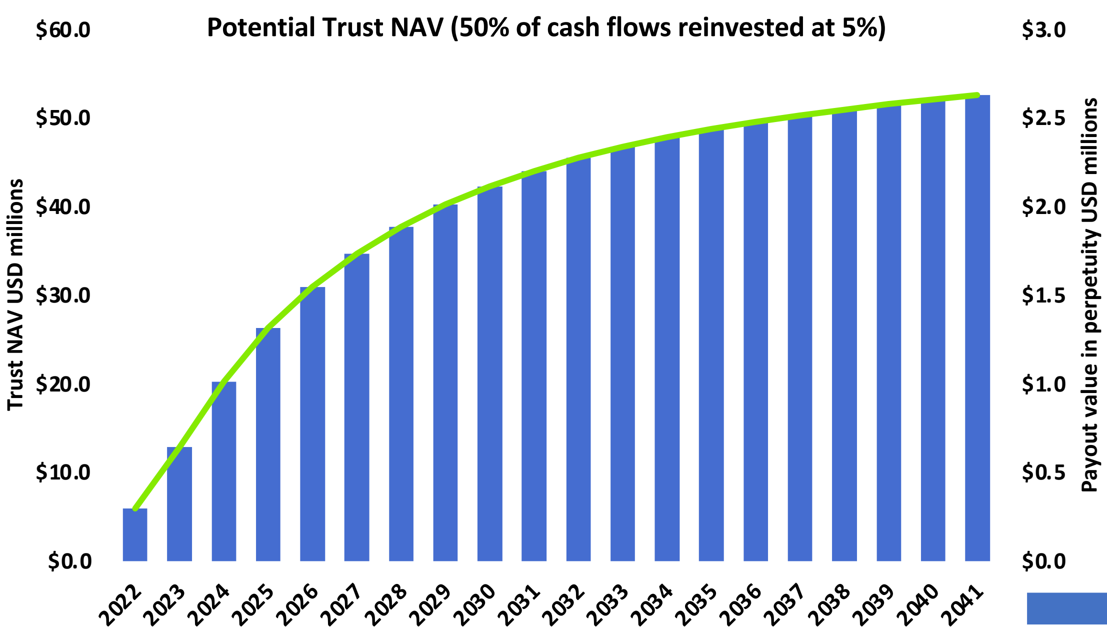
Operations management and accountability

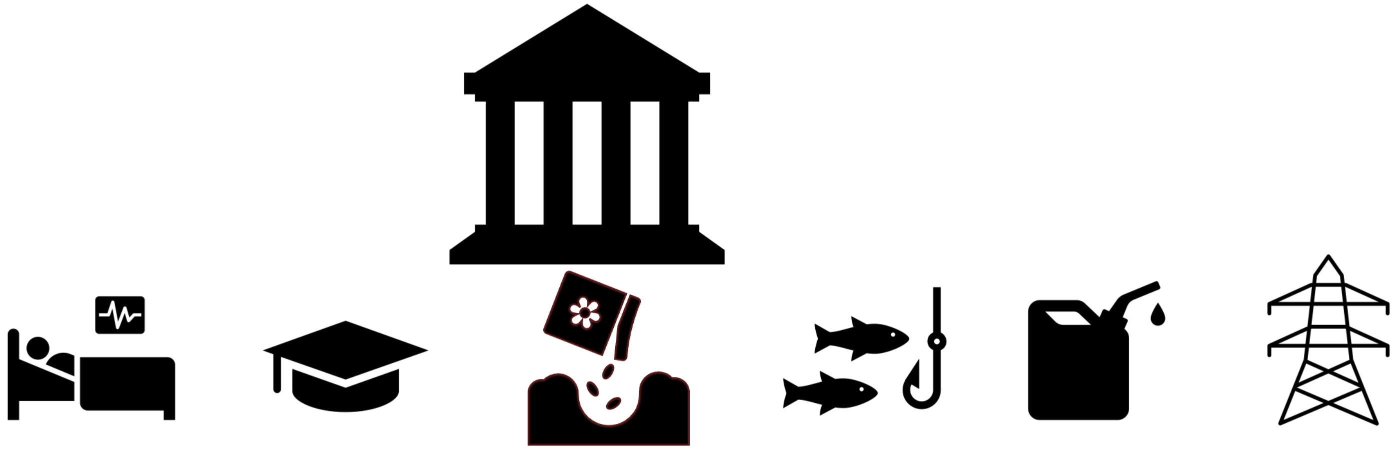
Working table (group)



- Comprised of community reps and supported by Ministry of Energy and Mines
- Formulate policies, project recommendations and administration

Invest 50% in projects and 50% in trust investment vehicle to generate income in perpetuity





Trust legal structure, policies, administration

Invest 100% of the investment income in projects

See footnotes in March 2023 Presentation on website

ESG leadership

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Four Pillars of Sustainability

SUSTAINABLE DEVELOPMENT GOALS

SASB SUSTAINABILITY ACCOUNTING STANDARDS BOARD

GRI

Carbon footprint
11.4 kg/bbl scope 1 in 2021

Commitment to giving back (Social Trust)
2.5% of fiscalized production
Transparently administered
Unified addendum signed aligning government, PetroTal, community

Preservation of Pacaya Samiria National Reserve
$3.5 million funding agreement for a 20 years monitoring study

0 **Zero hydrocarbon oil spills in 2021**

See the latest ESG report at www.petrotal-corp.com

See footnotes in March 2023 Presentation on website

PetroTal facilitates community empowerment

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Medical

Funded and installed X-ray, odontology, maternity ultra sound, and vison related equipment

Nursery ward created

SDG # 3

Education

> 40 student pre and post grade sponsorships

~3,000 school kits for elementary students

Technology

Computers and IPADS provided to students

SDG # 4 & 5

Water

Clean water management and monitoring facilities

Power

Diesel for power

Solar panel projects

Bridge construction

Significant dock work

Breakwater installations for erosion mitigation

Landmarks

Bretaña library upgrades

Recycling infrastructure

Community centers

SDG # 6,7,9

Hire/Train Local

Training for 65 women to manufacture and sell organic fiber products

Trained 28 workers at technical institutes

No expats employed in Peru

Farming & Agriculture

Supply chain support for 420 farmers and their local products

Buyer of excess produce

Job Creation

> 500 temporary jobs created since July 2018

Fishing

Sustainable fishing projects

Commercial ice makers

Installed fishing cages for fishing projects

SDG # 8

SDG = Sustainable Development Goal
Per the UNDP (United Nations Development Program)

See footnotes in March 2023 Presentation on website

Development locations

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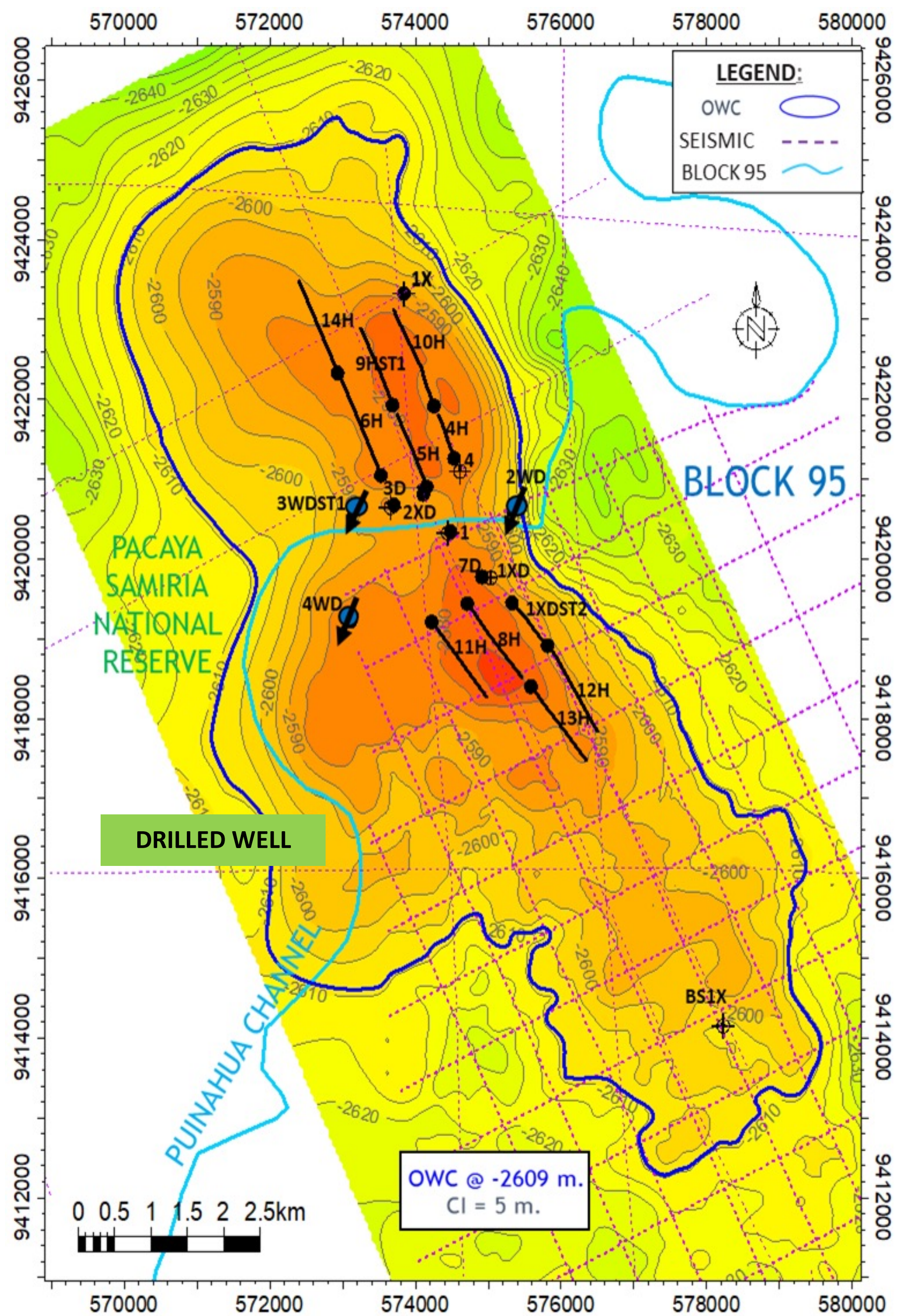
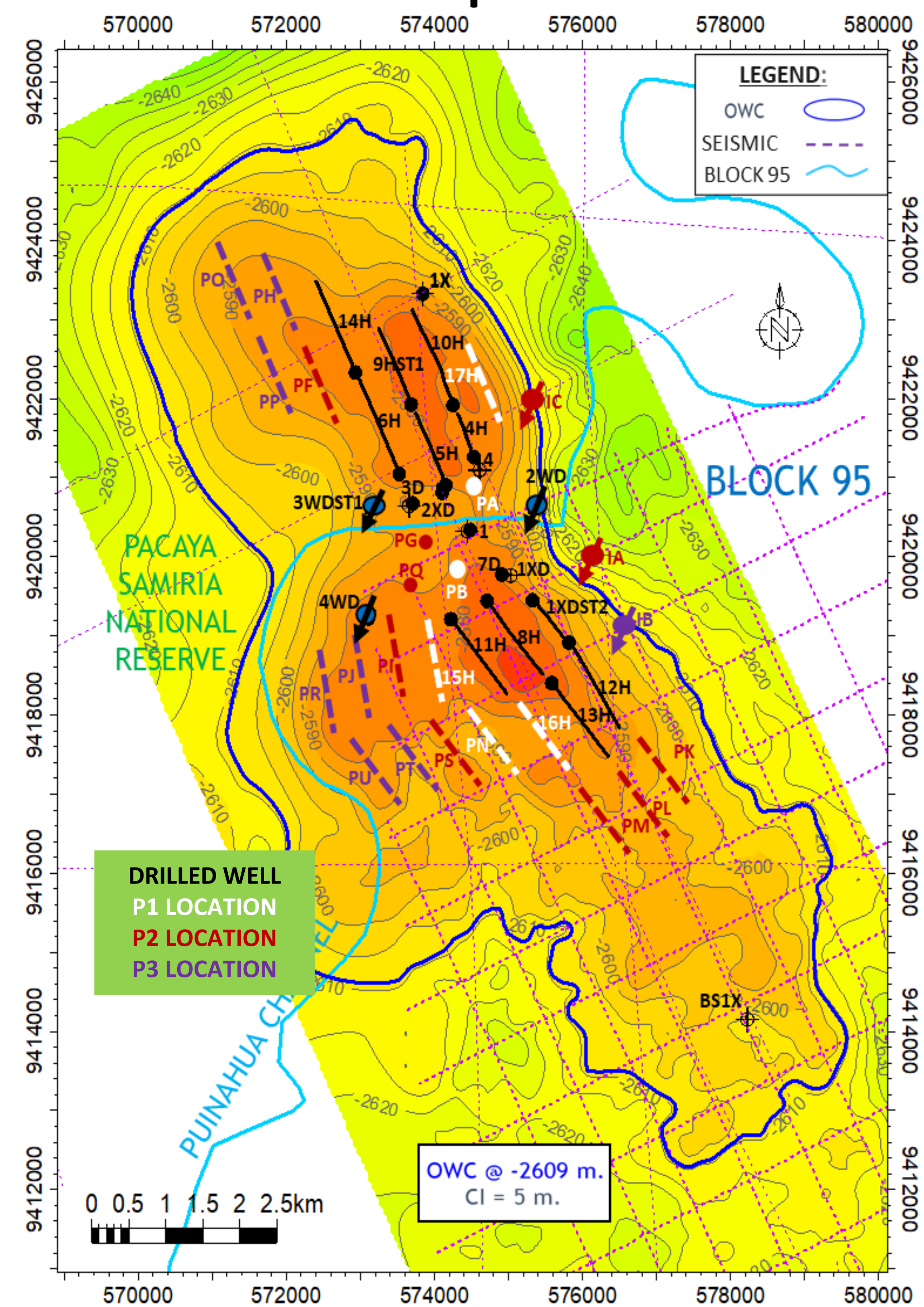
Technical characteristics

- Well defined four-way structure bounded by a reverse fault to the east – prolific geologic trap system
- Field size of **6,000 hectares** (6,000 city blocks)
- Vivian reservoir - Massive fluvial sands with excellent reservoir quality
  - Accountable for almost 70% of the oil production in the Marañón Basin in Peru
  - **Strong aquifer support** and water control using AICDs technology assures pressure maintenance and high volumes of oil recovery
- Analogous fields in the basin have **recovery factors of 22-42% vs Bretaña at 24%** - possible Bretaña upside recovery factor of incremental 10-25%
- **3P and 2P reserves case have 36 and 29 producing wells.** Potential exists for further infill drilling and "proving up" probable and possible drilling locations

Current field state

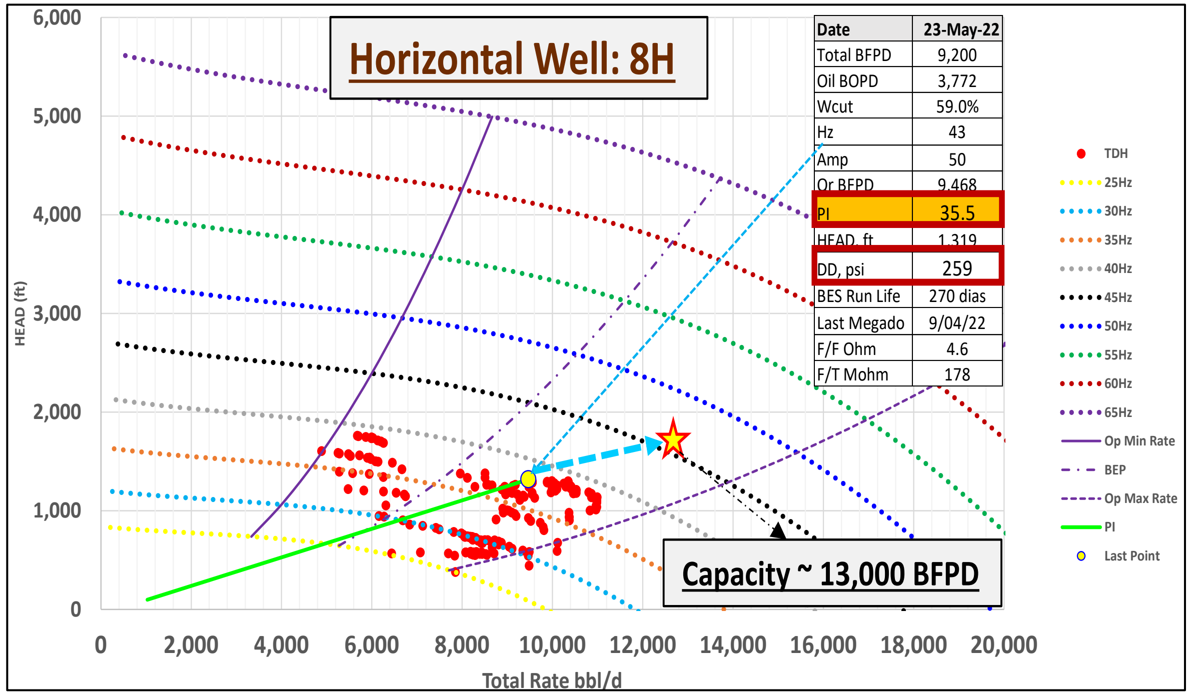


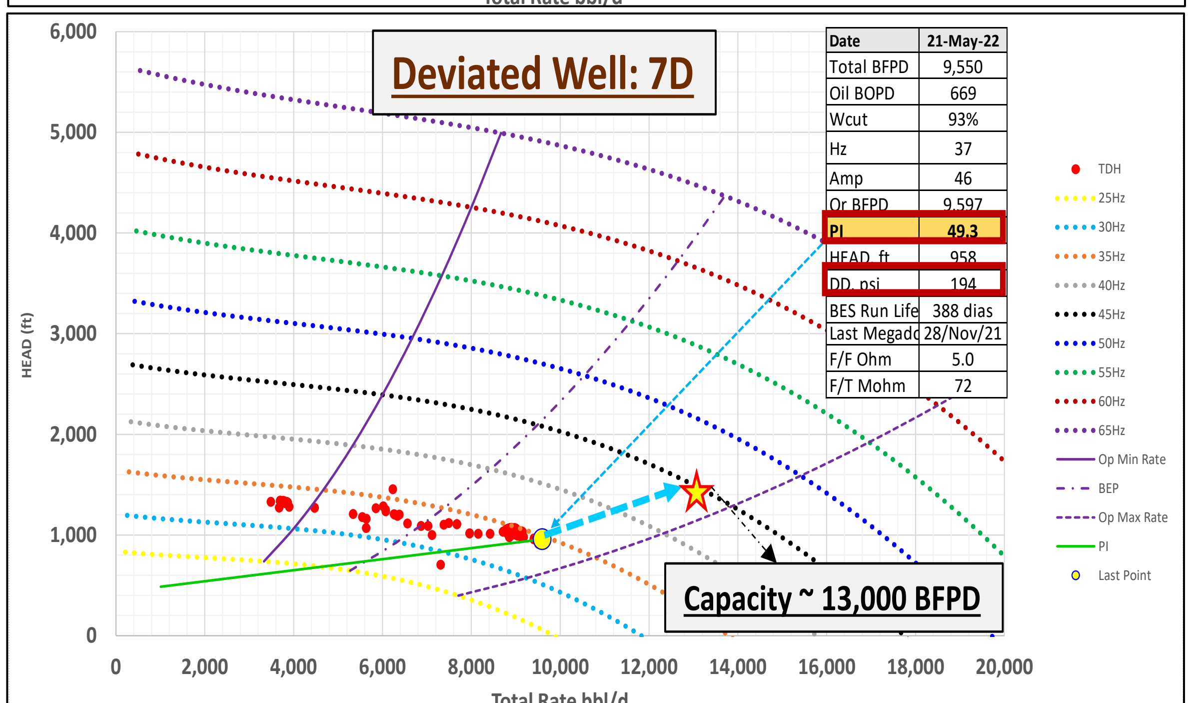
Full field development



Building a factory to process fluids

PetroTal





Water disposal and management are critical for long term strategy

Building a factory to process fluids is required because Bretaña will eventually produce crude oil with large water cuts

With 29 wells at an average 10,000 bfpd per well, Bretaña will process 290,000 bfpd:

- At a 10% oil cut, this is equivalent to 29,000 bopd
- At a 5% oil cut, this is equivalent to 14,500 bopd
- At a 3% oil cut, this is equivalent to 8,700 bopd

The above is possible due to:

- Bretaña's excellent well productivity
- Efficient use of AICD valves in horizontal wells to optimize oil and water production
- Optimum electro-submersible pump ("ESP") performance that allow us to maximize overall fluid production

The data to date shows that we can outperform due to:

- Well's high productivity index (PI > 30 bfpd/psi)
- Low pressure draw down (DD < 300 psi) that delays water channeling
- Observed draw down is less than 10% of reservoir pressure

The ESPs are:

- Working at low frequencies due to the wells' high PI's and motor loads of less than 50%
- Operating under optimum conditions according to the respective pump performance curves
- Expected to exceed 3 years of run life
- Able to lift 13,000 Bfpd, either from horizontal or deviated wells

Bretaña could eventually lift 286,000 bfpd in the 2P case, and 377,000 bfpd; which at 10% oil cuts would produce 28,600 bopd and 37,700 bopd, respectively

Three commercial sales routes

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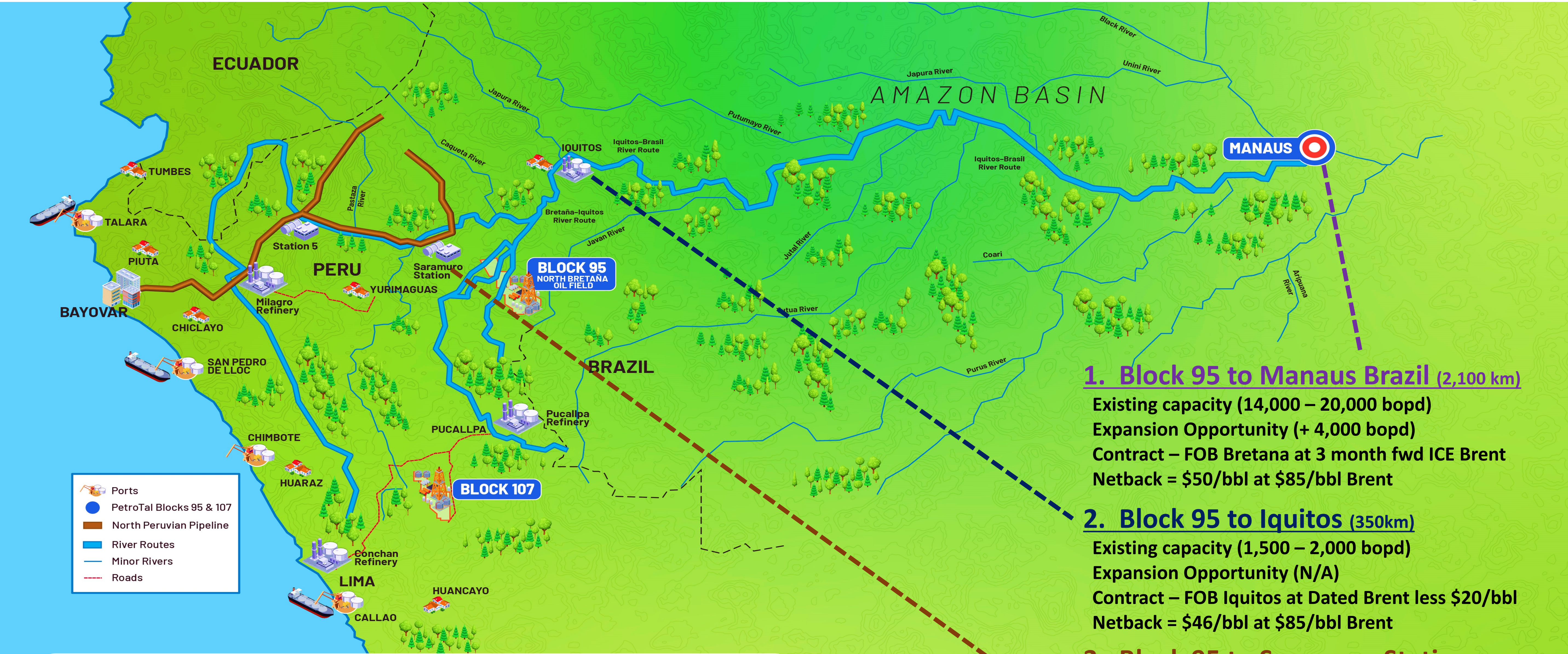


1. Block 95 to Manaus Brazil (2,100 km)

Existing capacity (14,000 – 20,000 bopd)
Expansion Opportunity (+ 4,000 bopd)
Contract – FOB Bretana at 3 month fwd ICE Brent
Netback = $50/bbl at $85/bbl Brent

2. Block 95 to Iquitos (350km)

Existing capacity (1,500 – 2,000 bopd)
Expansion Opportunity (N/A)
Contract – FOB Iquitos at Dated Brent less $20/bbl
Netback = $46/bbl at $85/bbl Brent

3. Block 95 to Saramuro Station (500km)

Existing capacity (0 – 25,000 bopd)
Expansion Opportunity (N/A)
Contract – FOB Saramuro at 8 month fwd ICE Brent
Netback = $45/bbl at $85/bbl Brent

Route to market strategy and targets

1. Optimize 1.5 million of available and moving barging capacity
2. Reduce round trip time for Brazilian route to under 50 days
3. Explore sales options to Pucallpa refinery and or direct barging access to pump station 5
4. Use ONP, if economically viable, to accommodate sales volumes above 20,000 bopd

See footnotes in March 2023 Presentation on website

Operational track record

PetroTal

Well	Initial Production	Initial max daily rate	Normalized production time	Cuml. Oil (Mar 23)	Payout	Cuml. NOI
Well 8H ($12 million capex)	Oct 2021	8,752 bopd	10.0 months	1.4 mmbbls	1.3 months	$75 million
Well 9H ($15 million capex)	Jan 2022	9,357 bopd	9.6 months	1.0 mmbbls	1.5 months	$53 million
Well 10H ($12 million capex)	Mar 2022	10,199 bopd	8.5 months	1.0 mmbbls	0.5 months	$53 million
Well 11H ($14 million capex)	July 2022	10,603 bopd	4.6 months	0.9 mmbbls	0.8 months	$48 million
Well 13H ($14 million capex)	Oct 2022	8,708 bopd	2.7 months	0.4 mmbbls	1.0 months	$21 million
Well 12H ($15 million capex)	Dec 2022	7,600 bopd	1.3 months	0.2 mmbbls	2.0 months	$11 million

~$82 million invested

~$261 million recovered to date

3.2x investment recycled in under 10 months of normalized producing time

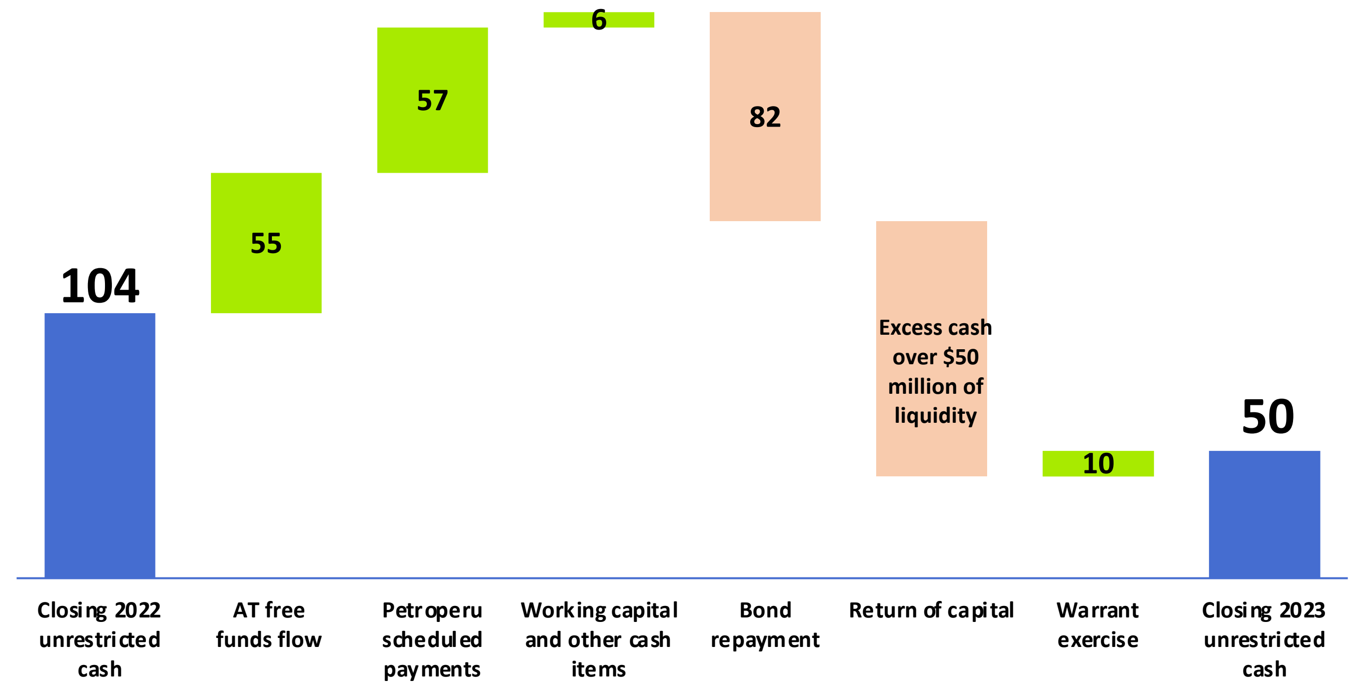
See footnotes in March 2023 Presentation on website

Financial summary

Financial summary (USD millions)

Key financial figures	2018	2019	2020	2021	2022
Total Cash	**26.3**	**21.1**	**9.1**	**74.5**	**120.0**
Total receivables	8.6	24.0	15.6	5.4	120.0
Net derivative liability (asset)	-	0.4	4.0	(36.7)	(20.3)
Short and long term debt	-	55.0	52.6	171.8	186.1
Adjusted net debt (surplus)	**(27.4)**	**10.4**	**31.9**	**55.3**	**(74.2)**
Decommissioning	11.1	17.6	21.1	22.2	13.4
Total Equity	77.5	121.1	137.2	204.3	399.0
NOI	**5.1**	**41.9**	**28.9**	**104.9**	**273.5**
G&A	(6.1)	(10.7)	(10.7)	(14.3)	(20.0)
EBITDA (NOI – G&A)	**(1.0)**	**31.2**	**18.2**	**90.6**	**253.5**
Net debt / EBITDA	**N/A**	**0.3x**	**1.8x**	**0.61x**	**N/A**

2023 cash sources and uses (USD millions)



Announced return of capital program

Dividends

May/June 23 — Based on Q1 2023 cash

Aug/Sept 23 — Based on Q2 2023 cash

Nov/Dec 23 — Based on Q3 2023 cash

~$0.015/share

$0.060/share (annualized)

13.9% yield ($0.45/share USD)

~$14 million per quarter

Buybacks

May/June 23 — **May/June 24**

10% of free float = ~60 million shares

Buyback cap based on volume restrictions = (~24 million shares)

Estimated amount of buybacks over next 12 months = ~36 million shares

~$14 - ~$20 million per year (4.5% of market capitalization)

Key highlights

- Currently **debt free**
- **Reinstated dividend and buyback plan**
- **Low decommissioning liability** from low well count and small field footprint
- Ability to **flex accounts payable** and use vendor financing
- Robust 2022 return on capital employed metrics at **47%**
- **~$70-$80 million (annualized) returning to shareholders (19% of market cap)**

See footnotes in March 2023 Presentation on website

Disclaimers

Forward-Looking Information

Certain information included in this presentation constitutes forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “estimate”, “propose”, “project” or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information in this presentation may include, but is not limited, statements about: the Company’s corporate strategy, objectives, strengths and focus; potential exploration and development opportunities; processing capacity, including pursuant to a proposed expansion of central processing facilities (CPF#2); expectations and assumptions concerning the success of future drilling, development, transportation and marketing activities; storage capacity; access to diversified markets, including pursuant to multiple export routes; intention of engaging joint venture partners to drill the Osheki prospect; the performance, economics and payouts of new and existing wells; decline rates; recovery factors; the successful application of technology and the geological characteristics of properties; capital program and capital budgets, including revised 2023 guidance and budget; future production levels and growth, including 2023 exit production, 2023 average production; cash flow; debt; shareholder return strategy; primary and secondary recovery potentials and implementation thereof; potential acquisitions; regulatory processes; drilling, completion and operating costs; commodity prices and netbacks; realization of anticipated benefits of acquisitions; hedging program; NPV-10 valuations; the performance of the management team and board; and ESG and CSR activities and commitments. Statements relating to “reserves” and “prospective resources” are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves or prospective resources described exist in the quantities predicted or estimated and that the reserves or prospective resources can be profitably produced in the future. Without limitation of the foregoing, future dividend payments, if any, and the level thereof, is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, free cash flow financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of PetroTal to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness.

The forward-looking information is 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, reservoir characteristics, recovery factor, exploration upside, prevailing commodity prices and the actual prices received for PetroTal’s products, the availability and performance of drilling rigs, facilities, pipelines, equipment, other oilfield services and skilled labor, royalty regimes and exchange rates, 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, the Company’s growth strategy, general economic conditions, prevailing commodity prices and future debt and equity financings. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, stock market volatility, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration, production and transportation; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety, environmental and regulatory risks), commodity price and exchange rate fluctuations, actions of OPEC and OPEC+ members, 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, and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. In addition, the Company cautions that current global uncertainty with respect to the spread of the COVID-19 virus and its effect on the broader global economy may have a significant negative effect on the Company. While the precise impact of the COVID-19 virus on the Company remains unknown, rapid spread of the COVID-19 virus may continue to have a material adverse effect on global economic activity, and may continue to result in volatility and disruption to global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company. Please refer to the risk factors identified in the Company’s most recent annual information form and management’s discussion and analysis which are available on SEDAR at www.sedar.com. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking information. The forward-looking information contained in this presentation is made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward-looking information contained in this presentation is expressly qualified by this cautionary statement.

Financial Outlook

This presentation contains future-oriented financial information and financial outlook information (collectively, “FOFI”) about PetroTal’s prospective results of operations, production, enterprise value, payout of wells, CAPEX, net debt, cash flow, EV/cash flow, free cash flow after debt service, capital efficiency, balance sheet strength, netbacks, EBITDA, net debt to annualized EBITDA, NPV-10, EUR, operating costs, break-even Brent oil price, royalties, corporate tax, tax pools and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumption outlined in the Non-GAAP measures section below. FOFI contained in this presentation was approved by management as of the date of this presentation and was provided for the purpose of providing further information about PetroTal’s anticipated future business operations. 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.

Forward looking CAPEX and OPEX assumptions in this presentation are consistent with the NSAI Reserve Report as at Dec 31, 2022 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.

Disclaimers (continued)

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Oil and Gas Advisories

Crude Oil. All references to "oil" or "crude oil" production, revenue or sales mean "heavy crude oil" as defined in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Brent refers to Intercontinental Exchange "ICE" Brent.

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, 2022 (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 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.

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.

Disclaimers (continued)

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.

However, to PetroTal's knowledge, such analogous information has not been prepared in accordance with NI 51-101 and the COGE Handbook and PetroTal is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. 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.

Initial Production Rates. Any references in this document to test rates, flow rates, initial and/or final raw test or production rates, early production, test volumes and/or "flush" production rates are useful in confirming the presence of hydrocarbons, however, such rates are not necessarily indicative of long-term performance or of ultimate recovery. Such rates may also include recovered "load" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for PetroTal. In addition, the resource play which may be subject to high initial decline rates. Such rates may be estimated based on other third party estimates or limited data available at this time and are not determinative of the rates at which such wells will continue production and decline thereafter.

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.

Mean Estimate. *R*epresents the arithmetic average of the expected recoverable volume. It is the most accurate single point representation of the volume distribution.

All figures in US dollars unless otherwise denoted.

Disclaimers (continued)

PetroTal

Non-GAAP Financial Measures, Oil and Gas Metrics and Other Key Performance Indicators

This presentation contains certain financial measures, as described below, which do not have standardized meanings prescribed by generally accepted accounting principles (“GAAP”). In addition, this presentation contains metrics commonly used in the oil and natural gas industry and other key performance indicators (“KPI”), financial and non-financial, that do not have standardized meanings under the applicable securities legislation. As these non-GAAP financial measures and KPI are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used. It should not be assumed that the future net revenues estimated by PetroTal’s independent reserves evaluators represent the fair market value of the reserves, nor should it be assumed that PetroTal’s internally estimated value of its undeveloped land holdings or any estimates referred to herein from third parties represent the fair market value of the lands. These terms have been calculated by management and 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. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare PetroTal’s operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be relied upon for investment or other purposes. “Operating netback” is calculated by dividing net operating income by barrels sold in the corresponding period. The Company considers operating netbacks to be a key measure as they demonstrate Company’s profitability relative to current commodity prices. “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. “Net debt” means long term debt plus derivative obligation plus accounts payable less total cash and accounts receivables.“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. “EBITDA” means net operating cash flow less G&A. “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 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. “FDC” means future development costs. “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. “Operating cash flow” is revenue less royalties less field operating expenses (field netback). “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. “Half-cycle” means CAPEX related to drilling, completion, and equipping. “Mid-cycle” means half-cycle CAPEX plus costs to acquire land/leases. “IRR” is the internal rate of return, the discount rate required to arrive at an NPV equal to zero. Rates of return set forth in this presentation are for illustrative purposes. There is no guarantee that such rates of return will be achieved in the future. “Recycle ratio” is calculated as operating netback divided by F&D and is a measure for evaluating the effectiveness of the Company’s re-investment program. “Sustaining CAPEX” is the estimated capital required to bring on new production which offsets the natural decline of the existing production and keeps the year-over-year production flat.

Abbreviations

Bbl	Barrel	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
bopd	barrel of oil per day	Free Funds Flow	Adjusted EBITDA less CAPEX or as defined in footnotes
k bopd	Thousand barrel of oil per day	FFO	Funds flow from operations
F&D	Finding and development costs	Adj. EBITDA	Earnings before interest, taxes, depreciation, amortization, and after derivative adjustments EBITDA is Adj. EBITDA prior to derivative impacts
NIBD	Net interest bearing debt	Ha	Hectares
		PDP	Proved Developed Producing Reserves
Mmbbl	Million barrels of oil	1P	Proved Reserves
NGL	Natural gas liquids	2P	Proved + Probable Reserves
bbo	Billion barrels of oil	3P	Proved + Probable + Possible Reserves