Investor Presentation

Feb 2024 Update

PetroTal

PetroTal Overview

Corporate Summary	USD Millions
Trading Price Feb 1, 2024	$0.57/share USD
Basic Shares (millions)	917
Market Cap	**$523**
(Debt less cash) Q4 2023 estimate	($90)
Enterprise Value Q4 2023	**$433**
EV/2024 Adjusted EBITDA(2)	2.2x
2024 Guidance bopd	16,500 – 17,500
Corp. Derivatives	0 mmbbls
ONP Derivatives $72/bbl average	2.4 mmbbls
Current Production (bopd)	20,450(1)

(1) Average of Jan 2024
(2) 2024 Adjusted EBITDA at $200 million using $77/bbl Brent. See footnotes and disclaimers for financial definitions.

Company Value Proposition

Significant development running room and upside

Material reserves, production growth & free funds flow yield

Largest Peruvian oil producer

Outstanding operational performance

Waterflood pressure support (naturally occurring)

Robust heavy oil EBITDA margins

ESG leadership in Peru

Small field footprint (<30 acres)

6.96 kg/bbl in scope 1 emissions in 2022

Zero spills and volume discharge in 2022

Company History

2018
958 bopd
(greenfield)

2019
4,131 bopd
(330% growth)

2020
5,675 bopd
(37% growth)

2021
8,956 bopd
(58% growth)

2022
12,200 bopd
(19% growth)

2023
estimate
14,248 bopd
(17% growth)

2024

2024 PRODUCTION GUIDANCE: 16,500-17,500 bopd
(~20% production growth over 2023)

INVEST: approximately $135 million of capital in 2024

PRODUCED: >17 million barrels (inception – Feb 2024)

CASH GENERATION: ~$200 million of adjusted EBITDA in 2024

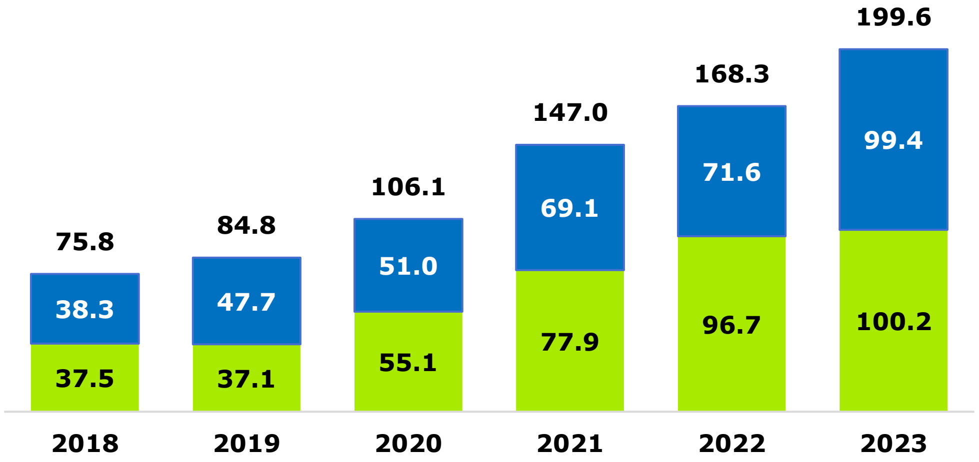
COMMERCIALIZE: adding two additional route to markets in 2024 (Ecuador OCP and Yurimaguas)

PRODUCTION CAPACITY: ~24,000 bopd

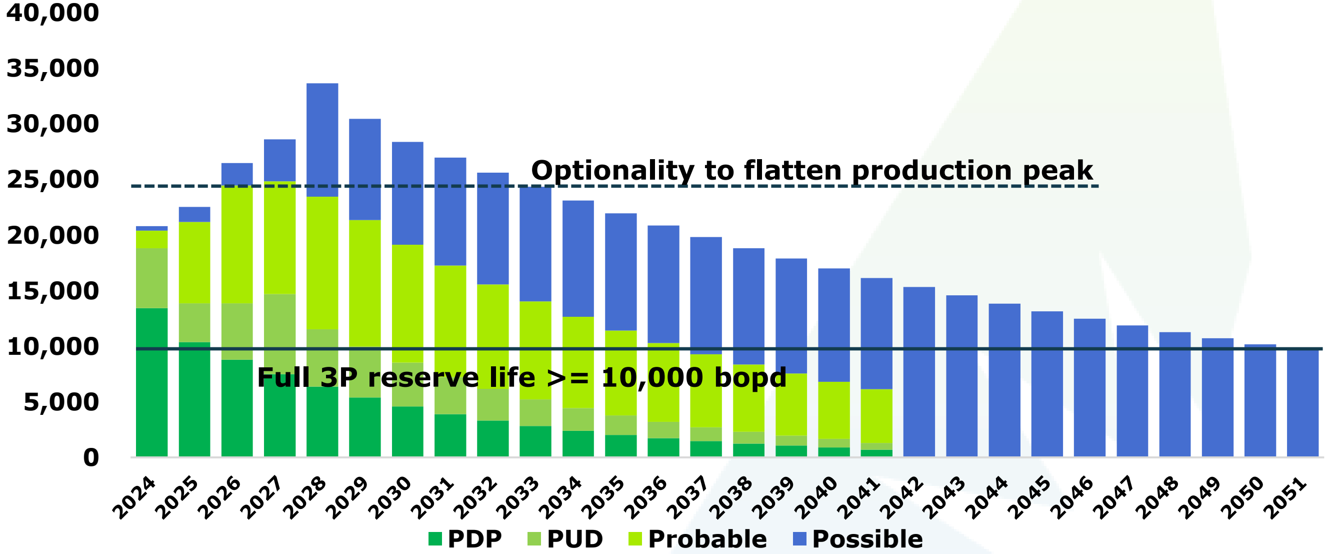
RETURN OF CAPITAL: returning an estimated $66 million of value through dividends and buybacks in 2024 with possibility of excess liquidity sweep amounts

Bretaña 2023 YE Reserves Summary

Reserves Summary (mmbbl)



Netherland Sewell (NSAI) Production Profile (bopd)



Key Highlights

- 2P and 3P **recovery factors of 26% and 34%,** delivered in six years from zero production
- 2023YE **2P EUR now at 117 mmbbls**
- **Full reserve life > 10,000** bopd under 3P case
- Peak production **of 34,000 bopd** plausible
- Ability to flatten peak production into **multi year production profile** of 20,000 to 25,000 bopd
- **Billion dollar 2P** after tax valuation at $1.8/share

Key Reserve Metrics (USD millions)

Case	Wells	OOIP mmbbl	Reserves mmbbl	Recovery Factor	A-tax NPV (10) (USD/share)	F&D USD millions	F&D/bbl	Recycle Ratio ($45/bbl netback)
1P	23	326	48	19.7%	$888 ($1.0/share)	$125	$6.4	7x
2P	32	442	100	26.3%	$1,639 ($1.8/share)	$551	$7.7	6x
3P	36	595	200	34.3%	$2,508 ($2.8/share)	$768	$4.5	10x

Short-Term Strategy with Long-Term Results

Debt-free balance sheet

- **Debt free near top of the pricing cycle** to maximize free cash flow to **equity holders**
- **De-risk balance sheet** long term
- **Ability to access debt capital** if pricing cycle turns bearish

Execution of 2P and 3P development plans

- Drilling **2P and 3P** development locations **without unnecessary overcapitalization** of facilities and infrastructure
- Varied development pace that will generate a long-term production profile of > **10,000 bopd for 15+ years**

Returning free cash flow to shareholders

- Implemented a structured and **accretive share buyback program**
- **Established a quarterly dividend program paying US$0.015/share with a cash sweep enhancement** that can be maintained over the long term

Securing additional sales routes

- Additional sales route, including the **reactivation of the ONP route**, will allow the Company to **avoid production constraints** in the dry season, **diversify credit risk**, and **unlock long term exploration** strategies for Blocks 95/107

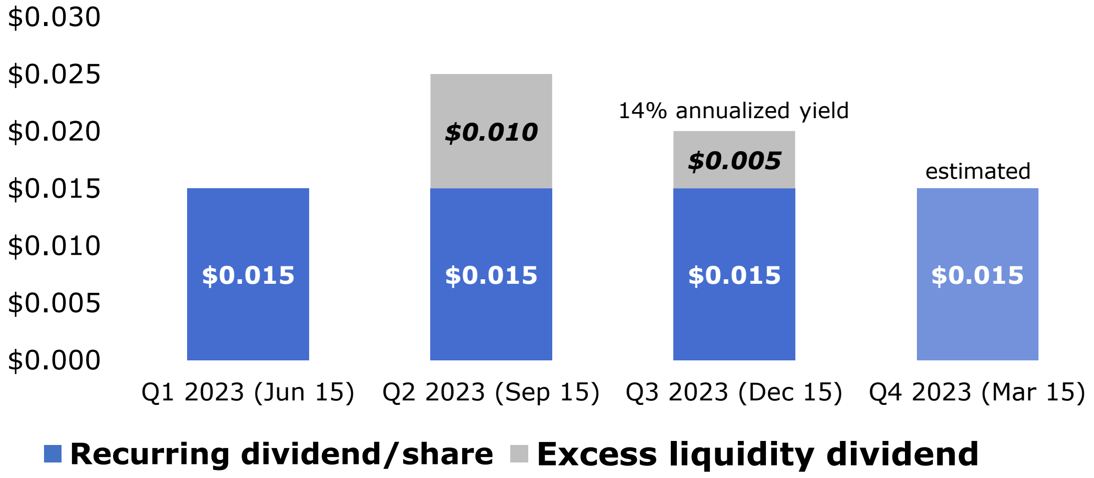
See footnotes for additional details and definitions

Return of Capital Overview

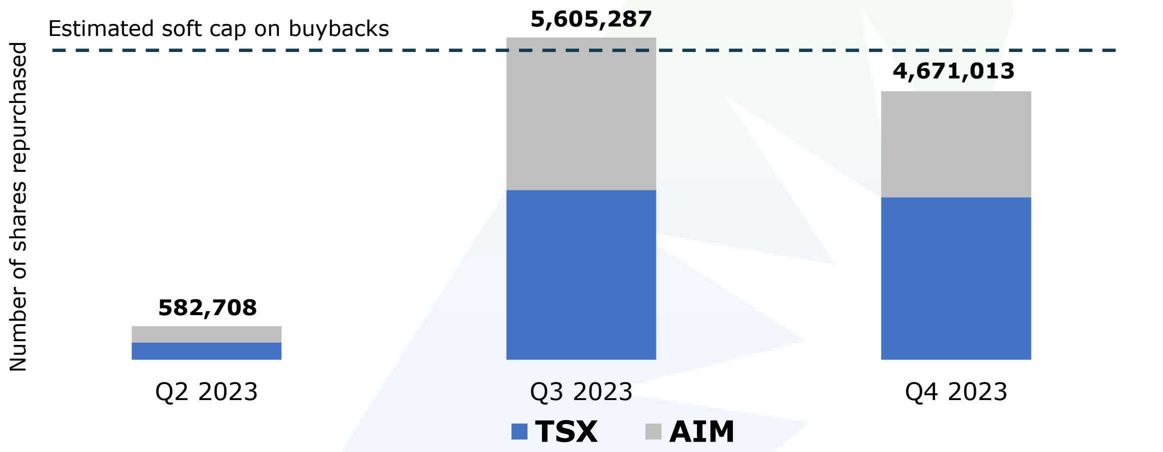
Dividends
$51 million returned *through Dec. 31, 2023*

Buybacks
$6.5 million returned *through Dec. 31, 2023*

Dividends Paid (USD/share)
Annualized yield based on $0.57/share USD



Share Buyback History
Buyback cap estimated using a $0.57/share USD



Dividend Policy
1. Pay a quarterly $0.015/share base dividend that is sustainable through low oil price environments
2. If economically viable on a forward-looking basis, increase the Company’s base dividend by an amount equal to excess liquidity over $60 million
3. Liquidity is existing cash available at dividend approval date that may be adjusted by portions of unused credit capacity and or future capital/working capital needs

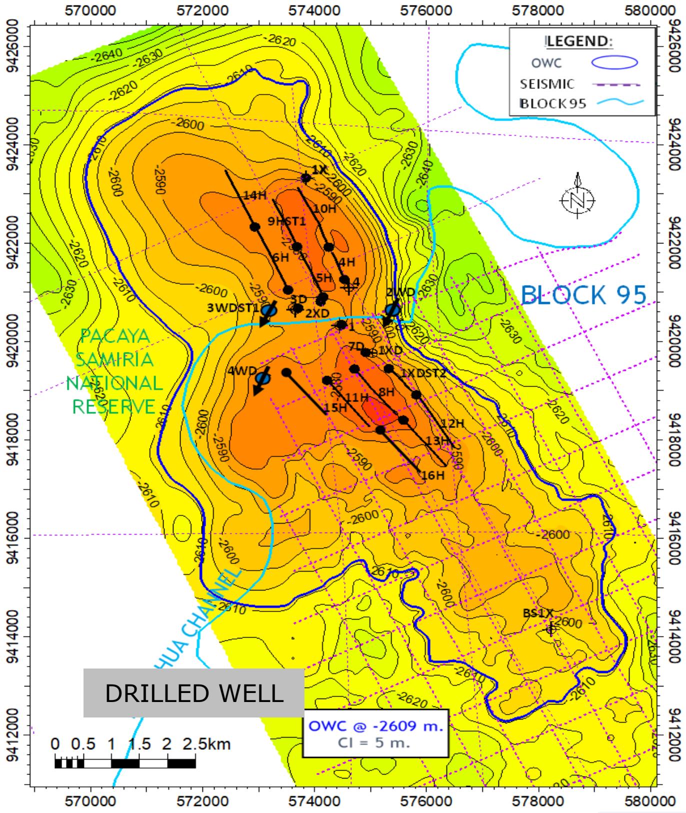
Buyback Policy
1. Buyback approximately 10% of the Company's public float subject to further volume and liquidity constrains set forth by the TSX and Company
2. Target approximately $3.0 million in buybacks per quarter totaling an estimated 4.0-5.0 million shares

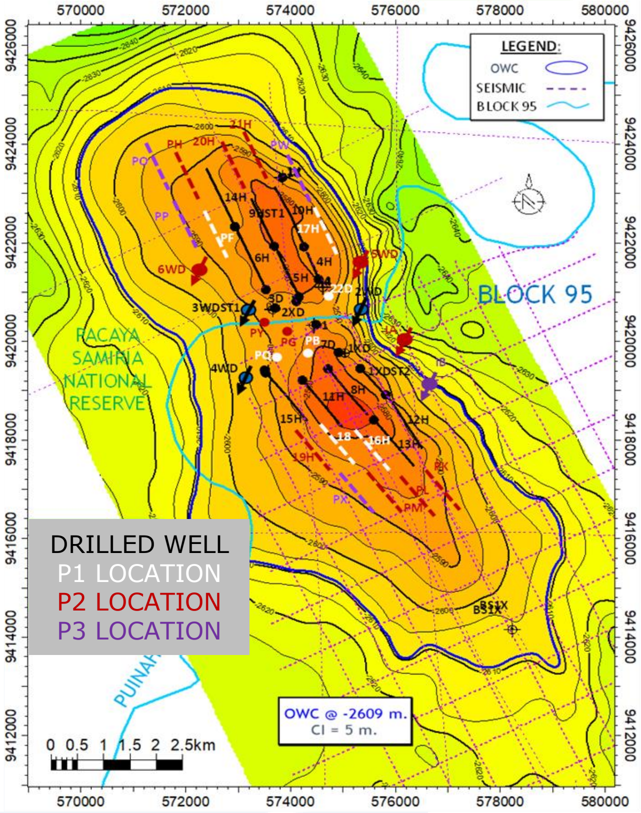
See footnotes for additional details and definitions

Development Locations

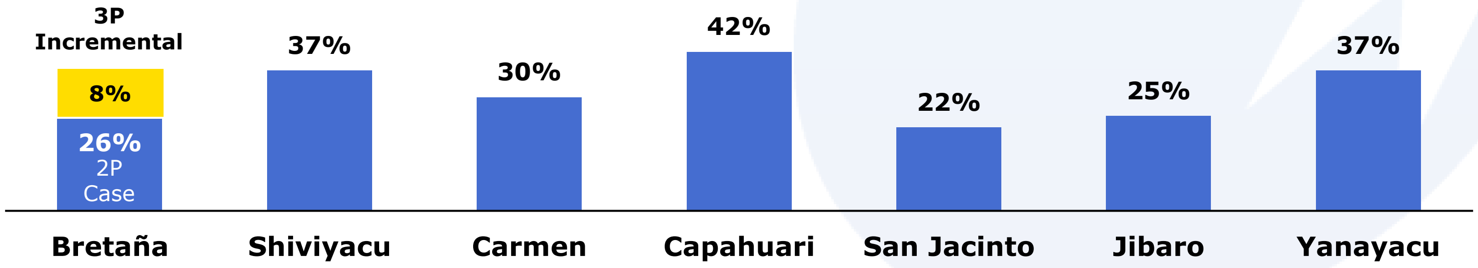
Technical Characteristics

- Well defined (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 AICD technology assures pressure maintenance and high volumes of oil recovery
- Analogous fields in the basin **have recovery factors of 22-42% vs Bretaña at 26%** – possible Bretaña upside recovery factor of incremental 10-25%
- **17 drilled oil wells plus 6 PUD locations**
- **2P and 3P reserves case have 32 and 36 producing wells.** Potential exists for further infill drilling and "proving up" probable and possible drilling locations





Analogous Field Recovery Factors



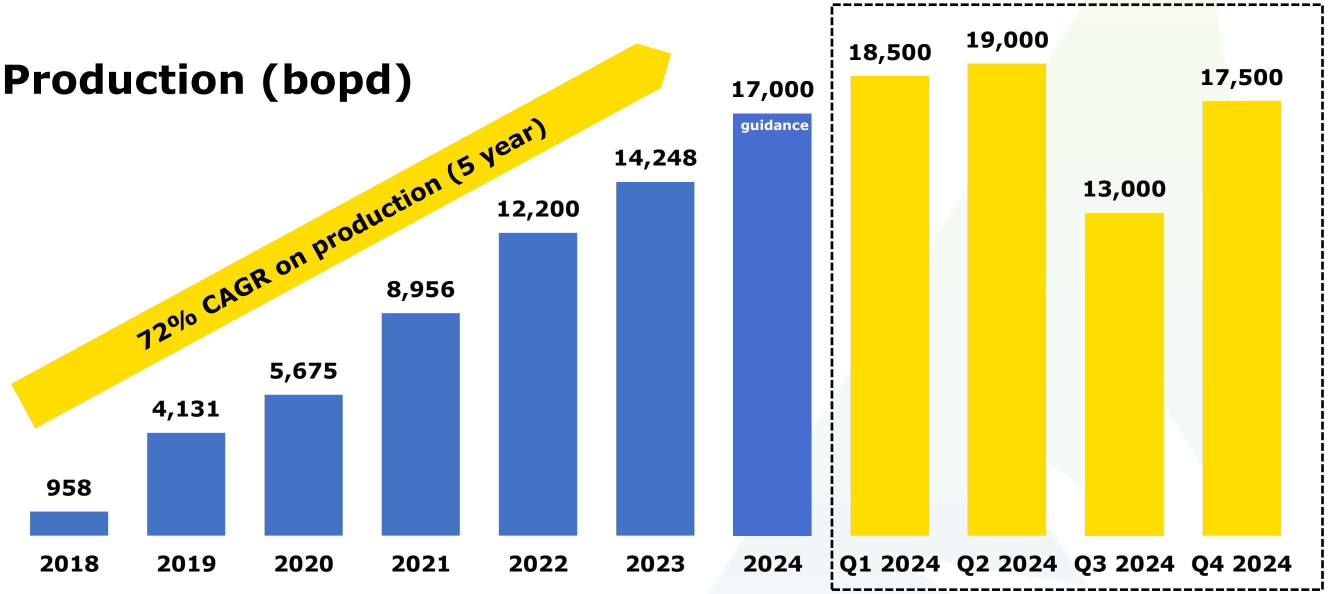
2024 Financial and Operational Guidance

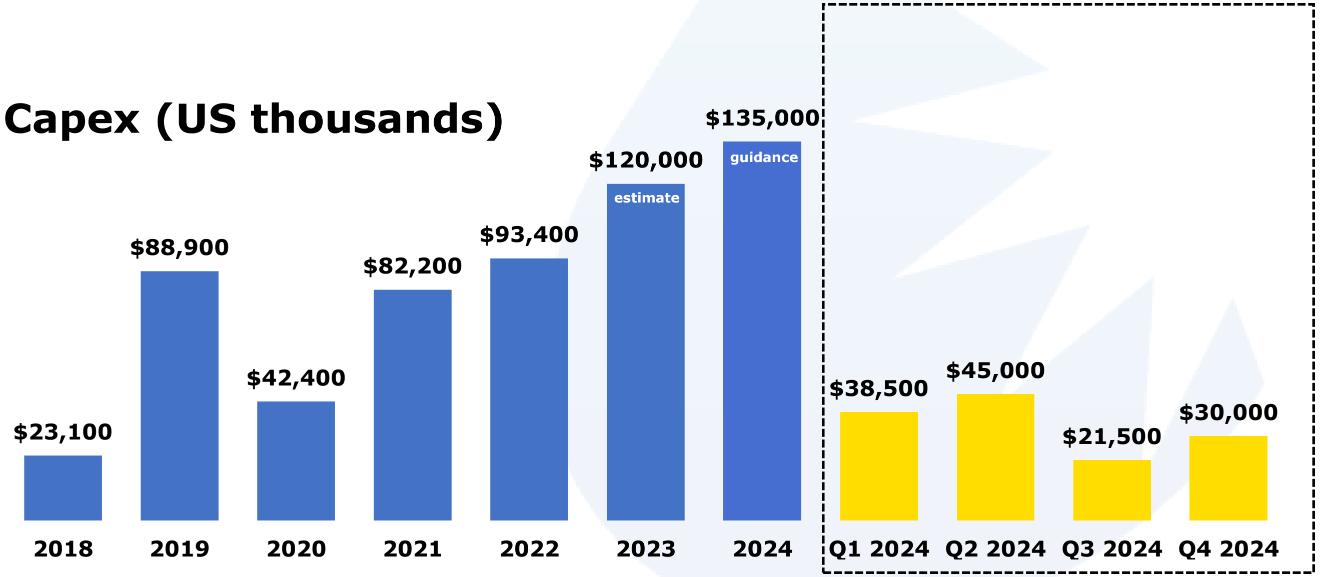
Summary in USD millions	2024
	(Jan 2024 guidance)
Production (bopd)	**~16,500–17,500**
Brent ($/bbl)	~$77
Net operating income	**$230**
G&A	($30)[1]
Adjusted EBITDA[2]	**$200**
Capex	($135)
Accrued tax and finance expense[3]	**($40)**
Free funds flow (pre return of capital)	**$25**
Working capital cash adjustments	$11
2024 generated distributable cash	**$36**

(1) Includes $4.2 million in social and community and $2.8 million in non cash G&A.
(2) See footnotes and non Gaap definitions.
(3) Amount reflects accrued taxes estimated for 2024 of $40 million. Cash tax payable in 2024 will be approximately $15 million.

Key highlights

- Drilling three and completing four new oil wells in 2024
- Commercializing two new route to markets (OCP/Yurimaguas)
- Spending $135 million in total Capex
- Initiating exploration programs in Blocks 95 and 107
- Generating $36 million of additional distributable cash in addition to the $90 million of unrestricted cash at Jan 1, 2024





2024 Bretaña Cash Flow Profile

Bretaña free cash flow 2024 (USD millions)

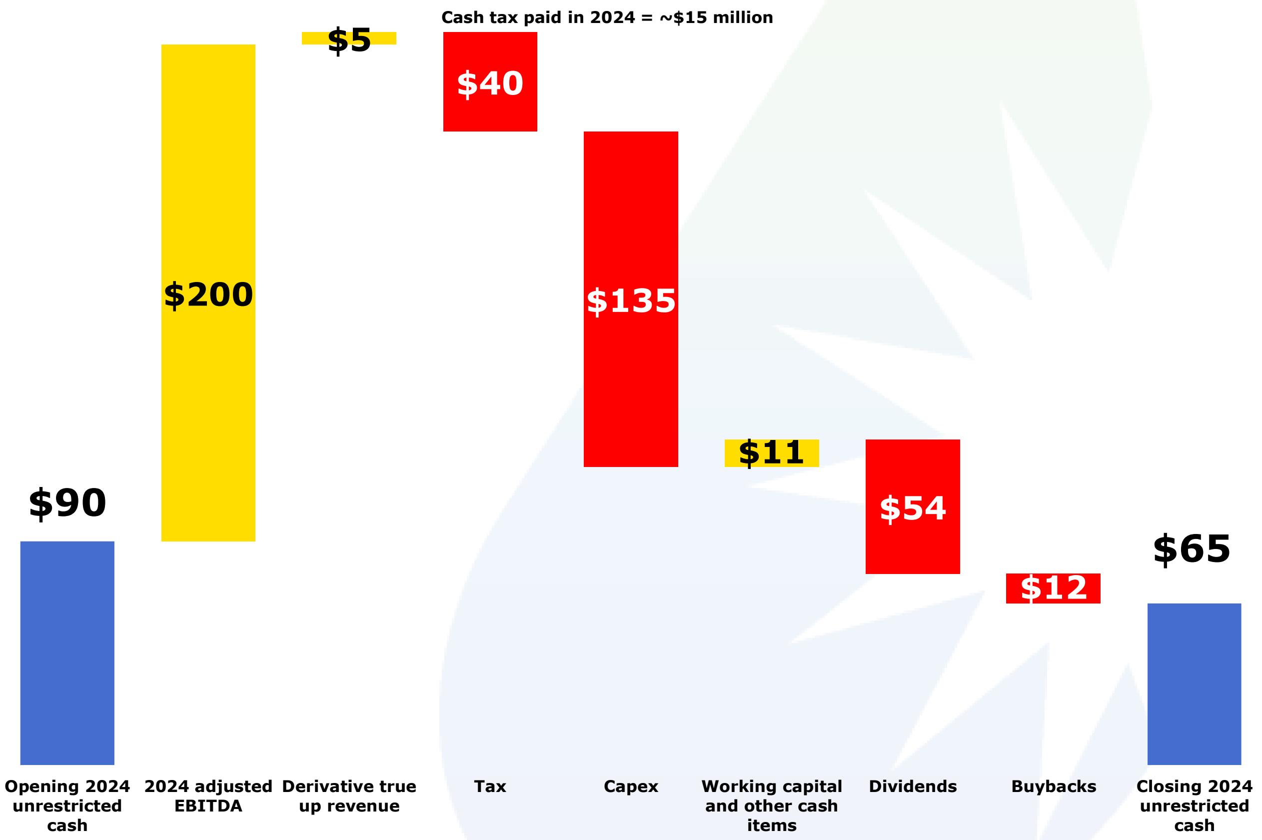
ANNUAL SALES (BOPD)

BRENT USD/BBL	13,000	15,000	17,000	19,000	21,000	23,000	25,000
$100	$79	$109	$139	$166	$192	$218	$243
$95	$65	$93	$120	$146	$170	$194	$218
$90	$51	$77	$102	$125	$148	$171	$193
$85	$37	$60	$83	$105	$126	$147	$168
$80	$23	$44	$65	$85	$104	$123	$142
→$77			**→$55**				
$75	$9	$28	$47	$65	$83	$100	$118
$70	($5)	$12	$28	$44	$60	$76	$92
$65	($19)	($5)	$10	$24	$39	$53	$67
$60	($33)	($21)	($9)	$4	$16	$28	$41

Free cash flow matrix notes and assumptions:

- Matrix assumes a full year of production and price
- A base run rate G&A range of approximately $30 million
- An estimated $15 million in cash tax in budget case (2024 accrued tax at $40 million with $25 million paid in early 2025)
- Company can defer up to $30 million in capex in shaded scenarios
- Post 2P development, maintenance capex is assumed at $25 million per year
- Matrix assumes a $120 million Capex program for Bretaña, 5% employee tax, 32% corporate tax and a 2.5% social trust royalty

2024 Total Cash Waterfall (USD million)



Active and Potential Sales Routes

Total Potential Capacity = 70,000 bopd

PetroTal will have commercialized additional sales routes prior to drilling its first exploration well in Block 95 assuming favorable seismic results

Available | In progress

	To	Status	Capacity	Timeline	Expandable
1	Station 1 direct	Petroperu credit N/A	25,000 bopd	N/A	TBD
2	Iquitos	Active	Up to 5,000 bopd	N/A	With blending
3	Manaus (Brazil)	Active	Up to 20,000 bopd	N/A	With dedicated storage
4	OCP (Ecuador)	Active pilot	5,000 bopd	2024 (pilot)	With additional barges
5	Station 5 direct	In progress	5,000 bopd	2024/2025	With facility investment
6	Yurimaguas	In progress	5,000 bopd	2024/2025	TBD
7	Lima via truck/barges	In progress	5,000 bopd	2024/2025	BioIFO opportunity

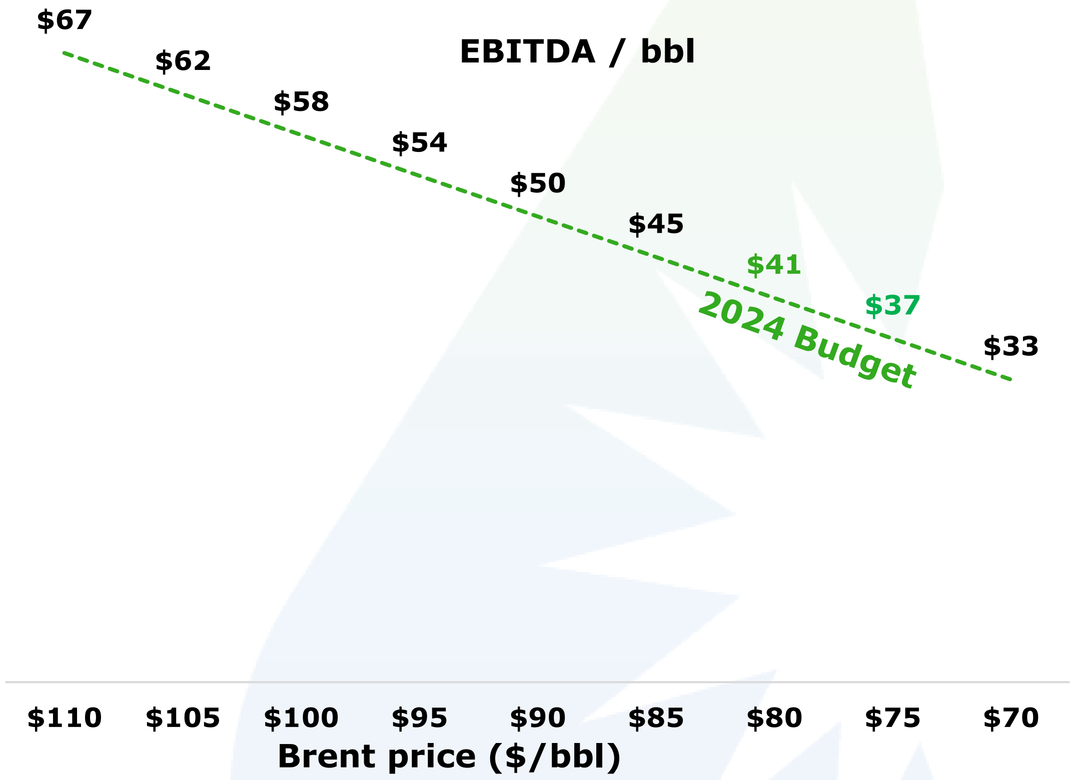
See footnotes for additional details and definitions

Netback Contribution by Sales Route

Run Rate Netback by Sales Route at 17,000 bopd ($/bbl)

Netback Summary $/bbl	Brazil	Iquitos	OCP / Yurimaguas (pilots)	Total	ONP (run rate)	OCP (run rate)	Yurimaguas (run rate)
Sales (bopd)	14,000	1,600	1,400	17,000	~20,000	~5,000	~5,000
Brent (@~$77/bbl)	**$77.0**	**$80.0**	**$77.0**	**$77.0**	**$74.0**	**$77.0**	**$77.0**
Differential *(estimated)*	($6.0)	($13.0)	($7.0)	($6.1)	($4.0)	($7.0)	($4.0)
Transportation *(estimated)*	($16.0)	-	-	($12.8)	($11.0)	-	-
Royalties and social trust	($5.5)	($6.0)	($5.5)	($5.8)	($5.0)	($5.5)	($5.5)
Net Revenue	**$49.5**	**$61.0**	**$64.5**	**$52.3**	**$54.0**	**$64.5**	**$67.5**
Lifting	($6.0)	($6.0)	($6.0)	($6.0)	($6.0)	($6.0)	($6.0)
Supervision & monitoring	-	($1.0)	($2.0)	($0.5)	($0.5)	($0.5)	($0.5)
Barging service inc. labor	-	($3.0)	($10.0)	($1.3)	($4.0)	($12.0)	($8.0)
Barging diesel	-	($1.0)	($2.0)	($0.2)	($1.0)	($1.0)	($1.0)
Pipeline & oil transfers	-	-	($5.0)	($0.9)	-	($3.0)	($2.0)
Trucking	-	-	($11.0)	($1.3)	-	-	($15.0)
Netback	**$43.5**	**$50.0**	**$28.5**	**$42.1**	**$42.5**	**$42.0**	**$35.0**
Cash portion of G&A	($4.1)	($4.1)	($4.1)	($4.1)	($4.1)	($4.1)	($4.1)
Normalized EBITDA	**$39.4**	**$45.9**	**$24.4**	**$38.0**	**$38.4**	**$37.9**	**$30.9**

Normalized EBITDA/bbl sensitivity at 17,000 bopd ($/bbl)



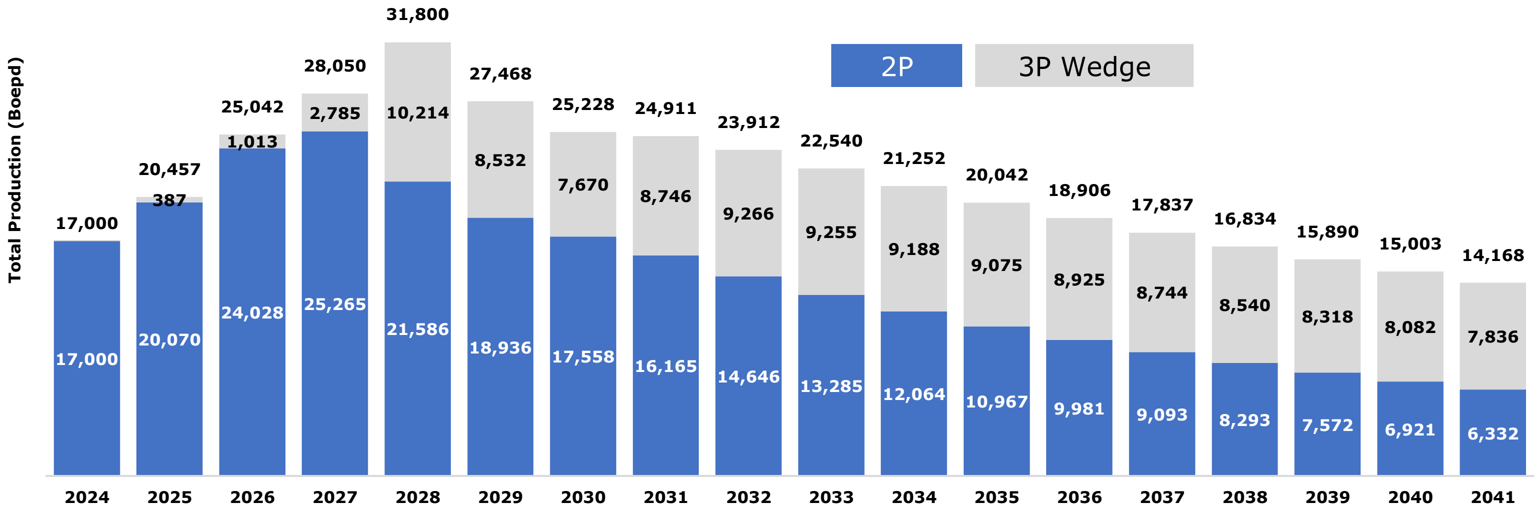
Key Highlights

- **Diluent not required**
- Table excludes erosion and community opex costs that are nonrecurring
- **>50% normalized EBITDA margins** at $80/bbl Brent
- **~80% of every dollar increase in Brent** falling to netback
- OCP and Yurimaguas estimated transportation includes oil transfer terminal fees, marketing fees, and secondary pipeline fees
- ONP, OCP and Yurimaguas run rate estimates are with commercial recurring volumes inclusive of opex scaling and cost synergies

See footnotes for additional details and definitions

Short-Term Strategy Generating Long-Term Cash Flow

Internally-generated (Bretaña only) Development Program (2P & 3P Reserve Estimates)(bopd)



2P Summary (USD millions)	2024	2025	2026	2027	2028	2029	2030	2031	'32-'41	Total
Exit well count	20	24	28	31	32	32	32	32	32	**32**
Funds flow @ $77/bbl Brent	$176	$215	$250	$272	$261	$221	$201	$184	$1,126	**$2,904**
Capex	(120)[4]	(136)	(120)	(109)	(55)	(22)	(21)	(19)	($116)	**($717)**
Dividends and buybacks	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	($634)	**($1,162)**
Discretionary free cash flow	**($10)**	**$13**	**$64**	**$97**	**$140**	**$132**	**$114**	**$99**	**$376**	**$1,026**
Cumulative ending cash (opening $90)	**$80**	**$93**	**$157**	**$254**	**$394**	**$526**	**$640**	**$739**	**$1,115**	**$1,115**

3P Summary (USD millions)	2024	2025	2026	2027	2028	2029	2030	2031	'32-'41	Total
Exit well count	20	24	28	32	36	36	36	36	36	**36**
Funds flow @ $77/bbl Brent	176	219	261	295	358	308	279	271	$2,014	**$4,182**
Capex	(120)	(145)	(133)	(144)	(134)	(36)	(33)	(32)	($241)	**($1,017)**
Dividends and buybacks	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	($634)	**($1,162)**
Discretionary free cash flow	**($10)**	**$8**	**$62**	**$85**	**$158**	**$206**	**$181**	**$173**	**$1,140**	**$2,003**
Cumulative ending cash (opening $90)	**$80**	**$88**	**$150**	**$235**	**$393**	**$599**	**$780**	**$953**	**$2,093**	**$2,093**

Summary	mmbbl
2P reserves (2041)	100
3P reserves (2051)	200

Key Highlights[1,2,3]

- Approximately **$1.0 billion** in **2P discretionary after-tax free funds flow** available to Company after returning **$66 million/year** to shareholders
- Approximately **$2.0 billion** in **3P discretionary free funds flow** available to Company after returning **$66 million/year** to shareholders
- Analysis includes **ongoing capital spending over and above the 2023 year ended reserve report estimates**
  - **Long term maintenance capex**
  - **Additional water handling**
  - **Erosion control initiatives**
  - **Investments into additional offtake routes/storage**
- $66 million annual return of capital fundable down to $58/bbl and $62/bbl Brent for 3P and 2P cases respectively on a long term basis

[1] Under a 2P development plan, $66 million return of capital per year is sustainable at a $27/bbl netback (~$62/bbl Brent) long term
[2] Under a 3P development plan, $66 million return of capital per year is sustainable at a $24/bbl netback (~$58/bbl Brent) long term
[3] Discretionary free funds flow is after tax free funds flow less dividends and buybacks
[4] $120 capex excludes ~$15 million of seismic and block 107 permitting

See footnotes for additional details and definitions

Long-Term Strategy

Achieve $2 billion in market capitalization via expansion

- Source **accretive M&A** opportunities in North and South America
- Source **inorganic block growth opportunities** in Peru
- Proceed with exploration development plans in **Blocks 95 and 107**

Achieve Bretaña production plateau

- **Drilling 3-4 wells per year** with little to no social related downtime
- Post-production plateau, maintain a production level that **optimizes infrastructure**
- Be the gold standard in Peru for **operational excellence as Peru's largest oil producer**
- Leverage our **diversified and commercially simple transportation strategy** allowing for cost savings over the long run

Materially meet or exceed ESG targets in Bretaña

- Realization and **completion of material carbon offset projects**
- **Biodiversity** related projects for preservation of the National Reserve Pacaya Samiria
- Management and funding of PetroTal's social trust with **economic development focus** in Puinahua

Return free cash flow to shareholders

- **Significant return of capital to shareholders via dividends and/or buybacks**

Optimize cost structure and operating synergies

- Make continued investments in field infrastructure projects that **lower operating costs** in an environmentally friendly way (diluent, power, and fuel focused)
- Target **20% to 30% OPEX reductions** post-production plateau in Bretaña via technology scaling

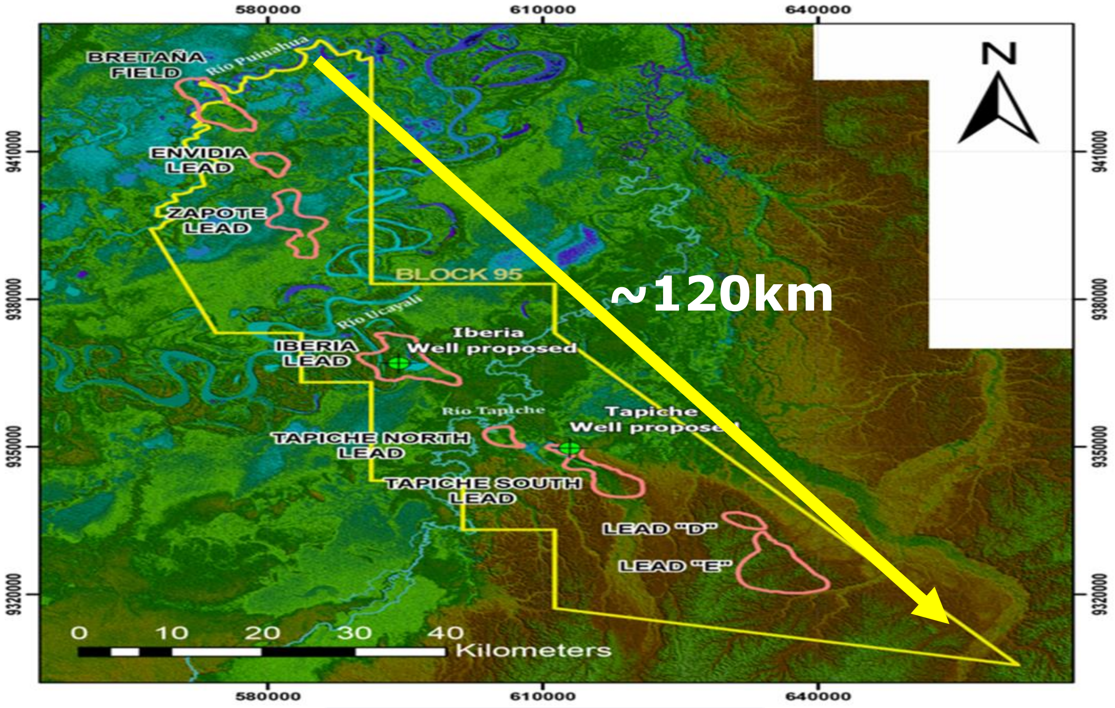
Block 95 Expansion Risked Spending Profile and Timeline

Drilling Schedule ($ millions)	Capex per well	Q1 24	Q2 24	Q3 24	Q4 24	Q1 25	Q2 25	Q3 25	Q4 25	Q1 26	Q2 26	Q3 26	Q4 26	Q1 27	Q2 27	Q3 27	Q4 27	Q1 28	Q2 28	Q3 28	Q4 28	Q1 29	Q2 29	Q3 29	Q4 29	Q1 30	Q2 30	Q3 30	Q4 30	Q1 31	Q2 31	Q3 31	Q4 31
Iberia	$20/well											x	x	x		x		x		x		x		x				+2 additional wells					
Tapiche Sou.	$20/well															x	x	x		x		x		x		x		x		x		x	
Lead E	$20/well																			x	x	x	x	x	x	+24 additional wells							
Zapote	$20/well																							x	x	x		x		x		x	
Discovery well / Water disposal	Seismic / Permits/ interpretation			$30 million								First production Commercial viability																+1 additional well					

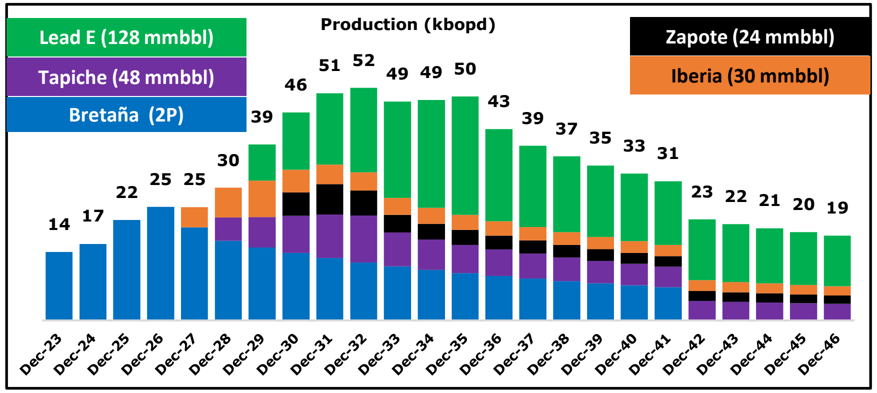
Block 95 Capex estimates (2024–2026)

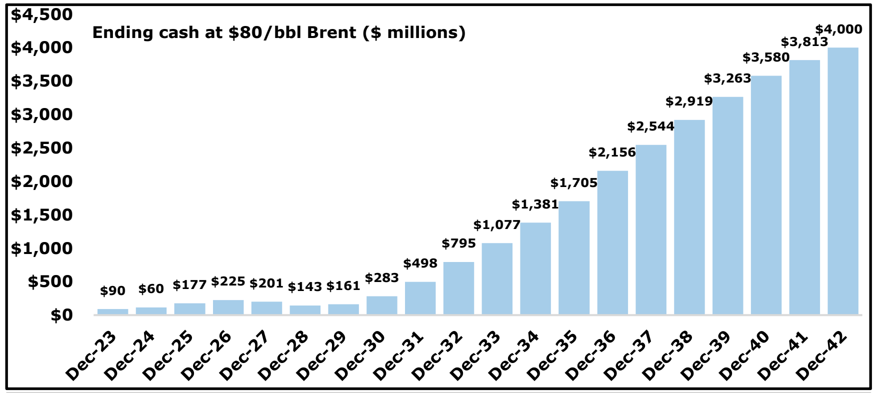
- **Risked dry hole Capex = ~$50-$70 million from 2024 – 2026**
  - ~$12 million in 2024 (seismic)
  - ~$18 million in 2025 (seismic)
  - ~$25-$30 million in 2026 (drilling)

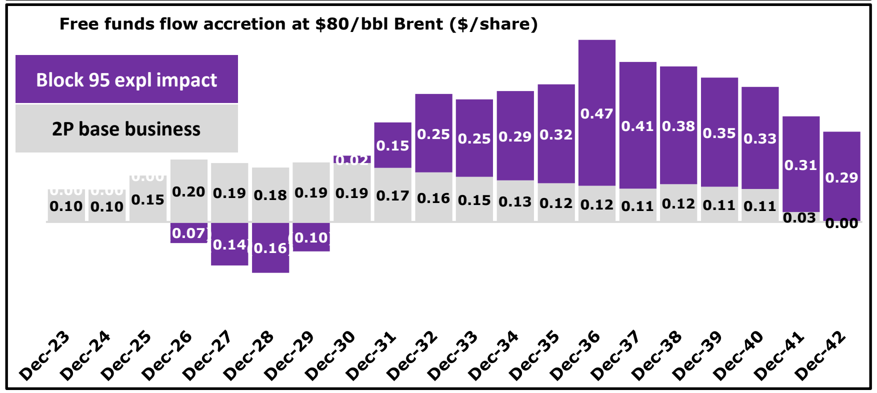
- **If deemed commercial → ~$10/bbl F&D for long term commerciality**



Profiling Bretaña and Block 95 Expansion (100% WI View @ $80/bbl Brent)







Summary		**5 YR**	**$/bbl**	**10 YR**	**$/bbl**	**15 YR**	**$/bbl**	**30 YR**	**$/bbl**
Oil produced	mmbbl	**39**		**119**		**203**		**327 (230 new)**	
Well count		31		66		78		78	
Avg production	**bopd**	21,070		32,572		37,057		29,832	
EBITDA	**millions**	**$1,631**	**$42**	**$4,997**	**$42**	**$8,628**	**$43**	**$14,230**	**$44**
Tax	"	($388)	($10)	($1,133)	($10)	($1,958)	($10)	($3,642)	($11)
Other	"	$30	$1	$30	$0	$30	$0	$30	$0
Funds flow	"	**$1,273**	**$32**	**$3,895**	**$33**	**$6,701**	**$33**	**$10,619**	**$32**
Capex	"	($798)	($20)	($2,485)	($21)	($3,203)	($16)	($3,263)	($10)
Change in debt	"	($80)	($2)	($80)	($1)	($80)	($0)	($80)	($0)
Change in equity	"	$8	$0	$8	$0	$8	$0	$8	$0
Dividends	"	($264)	($7)	($544)	($5)	($824)	($4)	($1,104)	($3)
Buybacks	"	($58)	($1)	($118)	($1)	($178)	($1)	($238)	($1)
Change in cash	"	$81		$675		$2,424		$5,942	
Ending cash	"	**$201**		**$795**		**$2,544**		**$6,062**	
Free funds flow	"	**$395**	**$10**	**$1,329**	**$11**	**$3,418**	**$17**	**$7,276**	**$22**

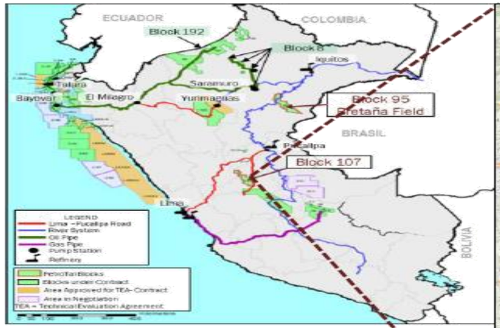
Key highlights

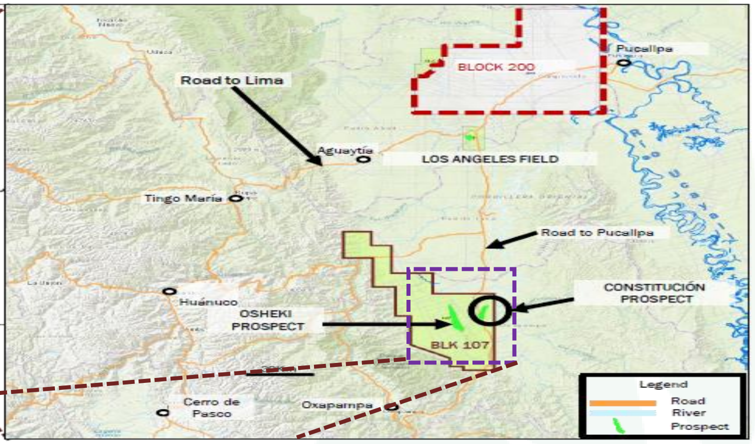
- **Minimum cash levels acceptable under an $80/bbl Brent scenario (long term price deck)**
- **Total ending cash in 2030 of ~$280 million (after dividend and buyback program)**
- **After tax free funds flow accretion neutral in mid 2033**
- **AT IRR > 40%**

Osheki-Kametza Technical Overview (Block 107)

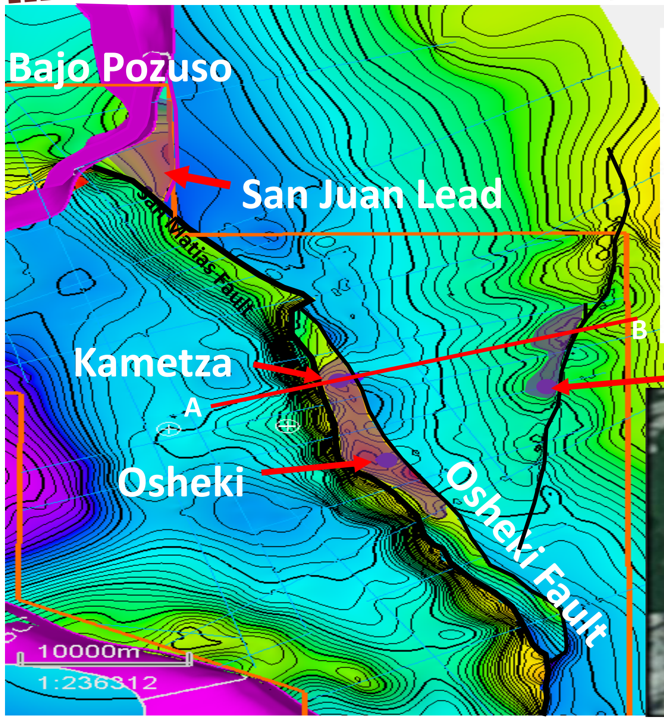
Unrisked prospects	Best estimate (mmbbl)	Mean (mmbbl)	Pg (%)
Osheki-Kametza	278.4	534.2	21 - 28
Constitución Sur	31.6	68.5	18 - 21
Unrisked leads	**Best estimate (mmbbl)**	**Mean (mmbbl)**	
Bajo Pozuzo	259.0	1,016.5	
Lead A	20.1	39.0	
San Juan	72.9	147.4	
Total	**662.0**	**1,805.6**	

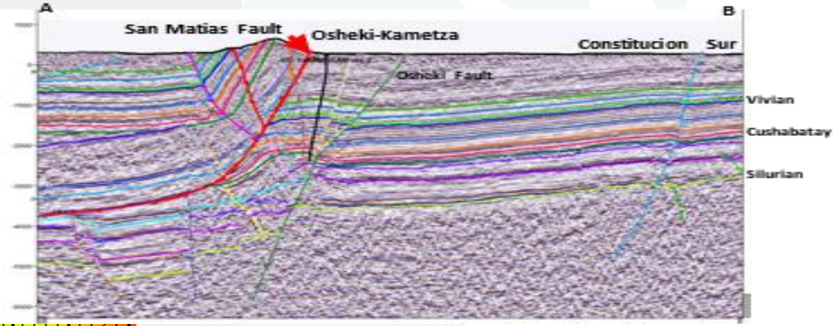
- 100% owned and operated block with > 252,000 hectares (> 622,000 acres), located in the Ucayali basin
- 3D geologic model supports Cretaceous reservoirs with oil charge from high quality Permian source rocks
- Two drillable prospects identified on 2-D seismic
  - Osheki-Kametza prospect
  - Constitución Sur prospect
- Recent reinterpretation of the seismic has shown that the Osheki prospect has two main structural culminations. To the south Osheki and to the north Kametza with a more accessible surface location.
- Due to smoother topography and dirt road access from main road to the Kametza surface location, the Osheki-Kametza prospect can now be drilled at an estimated cost of $28 million rather than the $40 million required to drill the Osheki surface location. Drilling costs for Constitución Sur are $22 million **(NPV neutral with tax benefits utilized by Block 95 if dry hole)**
- Exploration commitment to drill two exploration wells extended to 2025
- **PetroTal will seek a farmout partner** for the commitment wells or for longer term development after drilling the first well. Gran Tierra Energy has a 20% back-in interest in the block



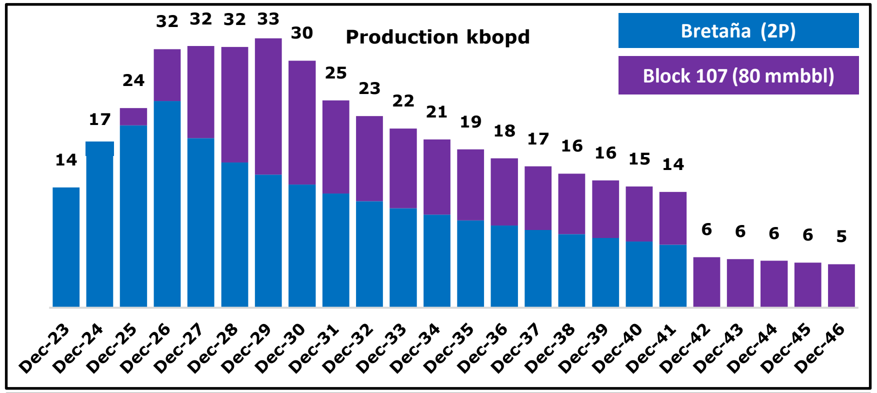


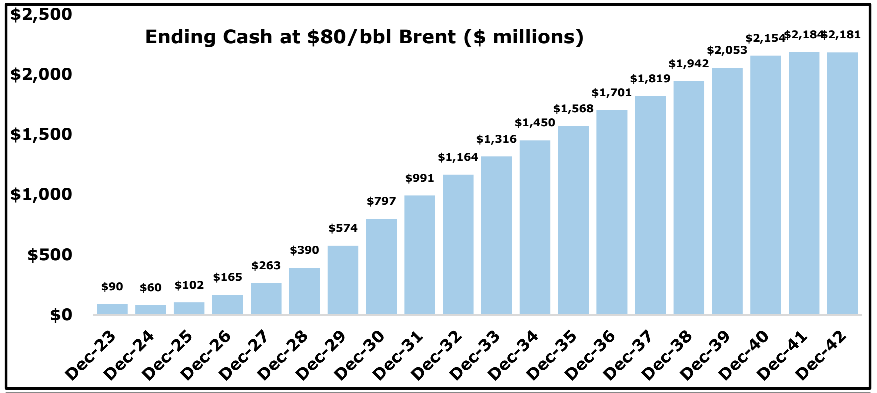
Depth Structural Map Cushabatay

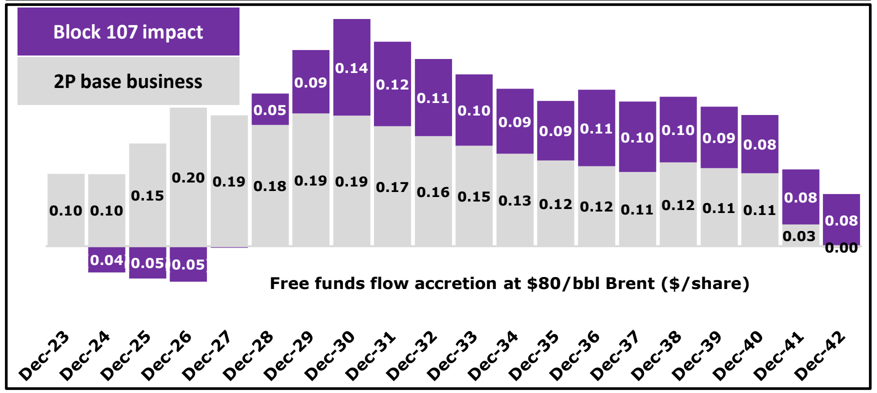




Profiling 2P Bretaña and Block 107 (100% WI View @$80/bbl Brent)







Summary		**5 YR**	**$/bbl**	**10 YR**	**$/bbl**	**15 YR**	**$/bbl**	**30 YR**	**$/bbl**
Oil produced	mmbbl	**45**		**97**		**133**		**176** (80 Block 107)	
Well count		42		56		56		56	
Avg production	**Bopd**	24,136		26,645		24,246		16,063	
EBITDA	**millions**	**$1,856**	**$41**	**$4,191**	**$43**	**$5,824**	**$44**	**$7,788**	**$44**
Tax	''	($446)	($10)	($1,029)	($11)	($1,482)	($11)	($2,150)	($12)
Other	''	$30	$1	$30	$0	$30	$0	$30	$0
Funds flow	''	**$1,440**	**$32**	**$3,192**	**$33**	**$4,372**	**$33**	**$5,668**	**$32**
Capex	''	($904)	($20)	($1,414)	($14)	($1,600)	($12)	($1,660)	($9)
Change in debt	''	($80)	($2)	($80)	($1)	($80)	($1)	($80)	($0)
Change in equity	''	$8	$0	$8	$0	$8	$0	$8	$0
Dividends	''	($264)	($6)	($544)	($6)	($824)	($6)	($1,104)	($6)
Buybacks	''	($58)	($1)	($118)	($1)	($178)	($1)	($238)	($1)
Change in cash	''	$143		$1,044		$1,699		$2,595	
Ending cash	''	**$263**		**$1,164**		**$1,819**		**$2,714**	
Free funds flow	''	**$457**	**$10**	**$1,698**	**$17**	**$2,693**	**$20**	**$3,929**	**$22**

Key highlights

- **Minimum cash levels acceptable under an $80/bbl Brent scenario (long term price deck)**
- **Total ending cash in 2030 of ~$1.2 million (after dividend and buyback program)**
- **After tax free funds flow accretion neutral in mid 2029**
- **AT IRR > 35%**

ESG Leadership

Four Pillars of Sustainability

- ENVIRONMENT
- GOVERNANCE
- SAFETY
- SHARED VALUE

Carbon footprint

- 6.96 kg/bbl scope 1 emissions in 2022 (decrease from 11.4 kg/bbl in 2021)

Commitment to giving back (Social Trust)

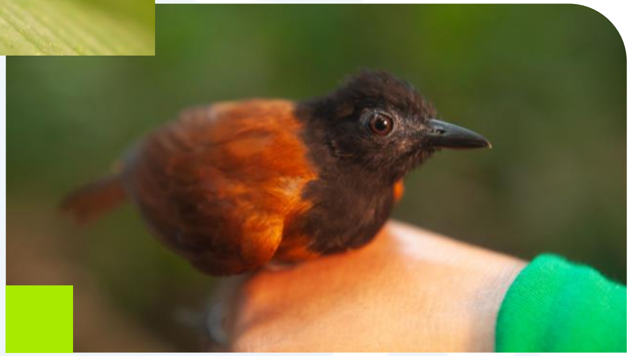
- 2.5% of fiscalized production
- Transparently administered
- Unified addendum signed aligning government, PetroTal, community

Preservation of Pacaya Samiria National Reserve

- $3.5 million funding agreement for a 20 year monitoring study

Zero hydrocarbon oil spills in 2022 & 2021






See the latest ESG Sustainability report at www.petrotalcorp.com

See footnotes for additional details and definitions

Appendix

Senior Management Team

Manolo Zúñiga, *Director, President & Chief Executive Officer*

- Native Peruvian with >30 years of experience in petroleum engineering
- Started career with Occidental Petroleum Corp ("Occidental") in Bakersfield & Block 192 in Peru
- Founder and former CEO of BPZ Energy
- Helped shape policies promoting oil investments in Peru, including the current long-term test regulation

Doug Urch, *Executive Vice President & Chief Financial Officer*

- Previously Executive Vice President, Finance and Chief Financial Officer of Bankers Petroleum Ltd
- Chartered Professional Accountant (CPA) and a designated member of the Institute of Corporate Directors (ICD)
- Director of PetroTal since inception and was Chairman of the Board from June 2018 until November 2019

Jose Contreras, *Senior Vice President, Operations*

- Over 25 years experience managing complex oil production and technical operations
- Various executive roles ranging from guiding international safety, security, and sustainability performance for projects and drilling; ensuring safe and efficient upstream and midstream onshore operations
- Mr. Contreras holds a Bachelor of Science in Chemical Engineering from the Universidad Central de Venezuela and a Master of Science in Petroleum Engineering and Project Development from the Institut Français du Pétrole

See footnotes for additional details and definitions

Board of Directors

Highly-Experienced Governance

Mark McComiskey, *Non-Executive Director and Chairman*

- Partner of Avaio capital with a focus on energy and digital infrastructure
- Founding Partner of Vanwall Capital and Managing Partner of Prostar Capital
- Former Principal of Clayton, Dubilier & Rice, Inc. and an associate at the law firm of Debevoise & Plimpton, LLP

Roger Tucker, *Non-Executive Director*

- CEO of Africa Oil
- Over 30 years working as a senior executive in the Energy Sector
- Work history in multinational major oil and gas companies, independent E&Ps and private equity investing

Eleanor Barker, *Non-Executive Director*

- President of Barker Oil Strategies since 2017
- Formerly worked in industry for Esso and Gulf Canada
- Former Oil and Gas Investment Analyst for over 30 years

Gavin Wilson, *Non-Executive Director*

- Investment Manager for Meridian
- Former founder & manager of RAB Energy & RAB Octane listed investment funds

Jon Harris, *Non-Executive Director*

- CEO of Gulf Keystone Petroleum
- Over 30 years senior leadership experience in international E&P Companies
- Masters of Engineering in Fuel and Energy from the University of Leeds, UK

Felipe Arbelaez Hoyos, *Non-Executive Director*

- Current Senior VP Hydrogen and CCS for BP
- Over 20 years of senior commercial and ESG experience in international oil and gas
- Masters of Mechanical Engineering and Finance

Emily Morris, *Non-Executive Director*

- Private corporate financial consultant in energy
- Over 20 years of investment banking experience in London
- Includes research, fund management, sales, and M&A advisory across resource sectors

Manolo Zúñiga, *Director, President and CEO*

- See bio on previous slide

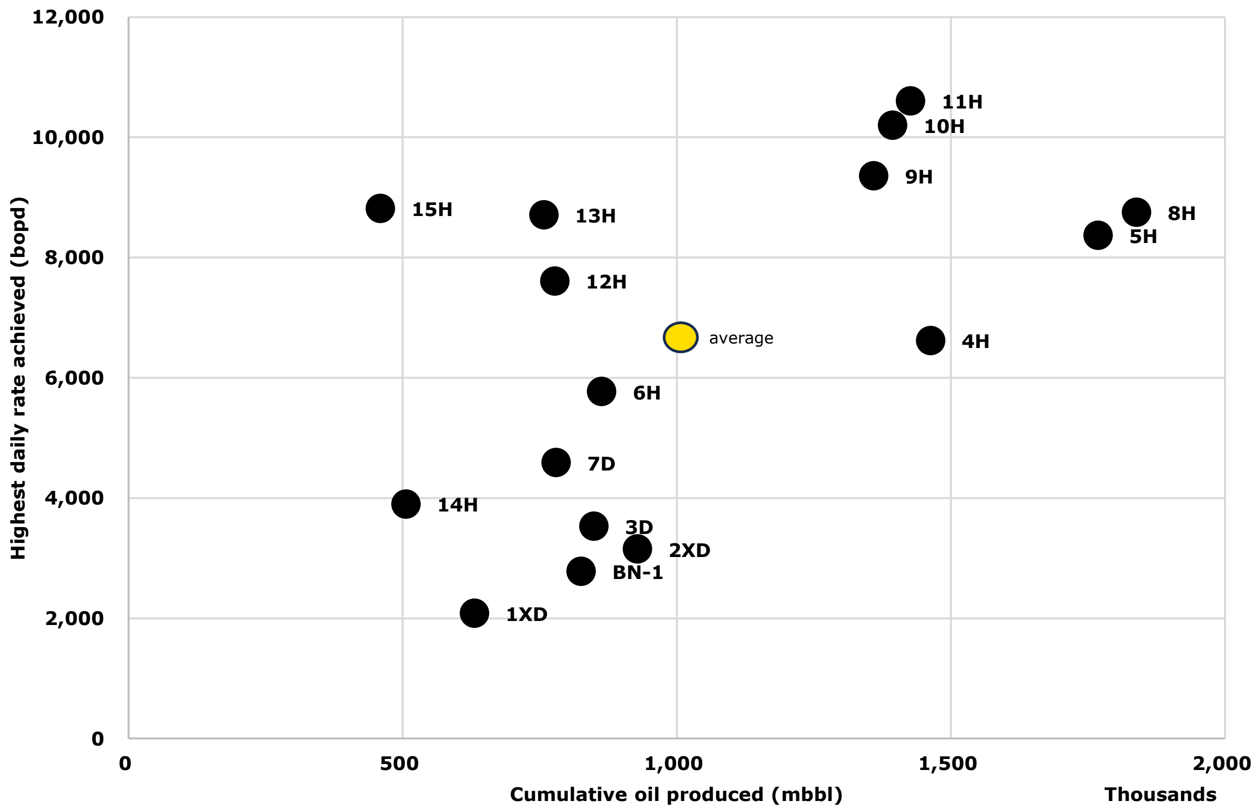
2024 Drilling Schedule

2024	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
Drilling capex (in millions)	**Q1 = $19**			**Q2 = $24**			**Q3 = $6**			**Q4 = $1**		
16H completion												
17H drill												
18H drill												
19H drill												
Rig Assessment/Upgrade												

- **$50 million drilling plan** that considers sales bottlenecks driving 20% production growth in 2024 (seasonal river changes and barging availability)
- **An additional $57 million** budgeted for various production and water facility projects to support current and future growth

Operational Track Record

Max oil rate vs cumulative oil (inception until Dec 31, 2023)



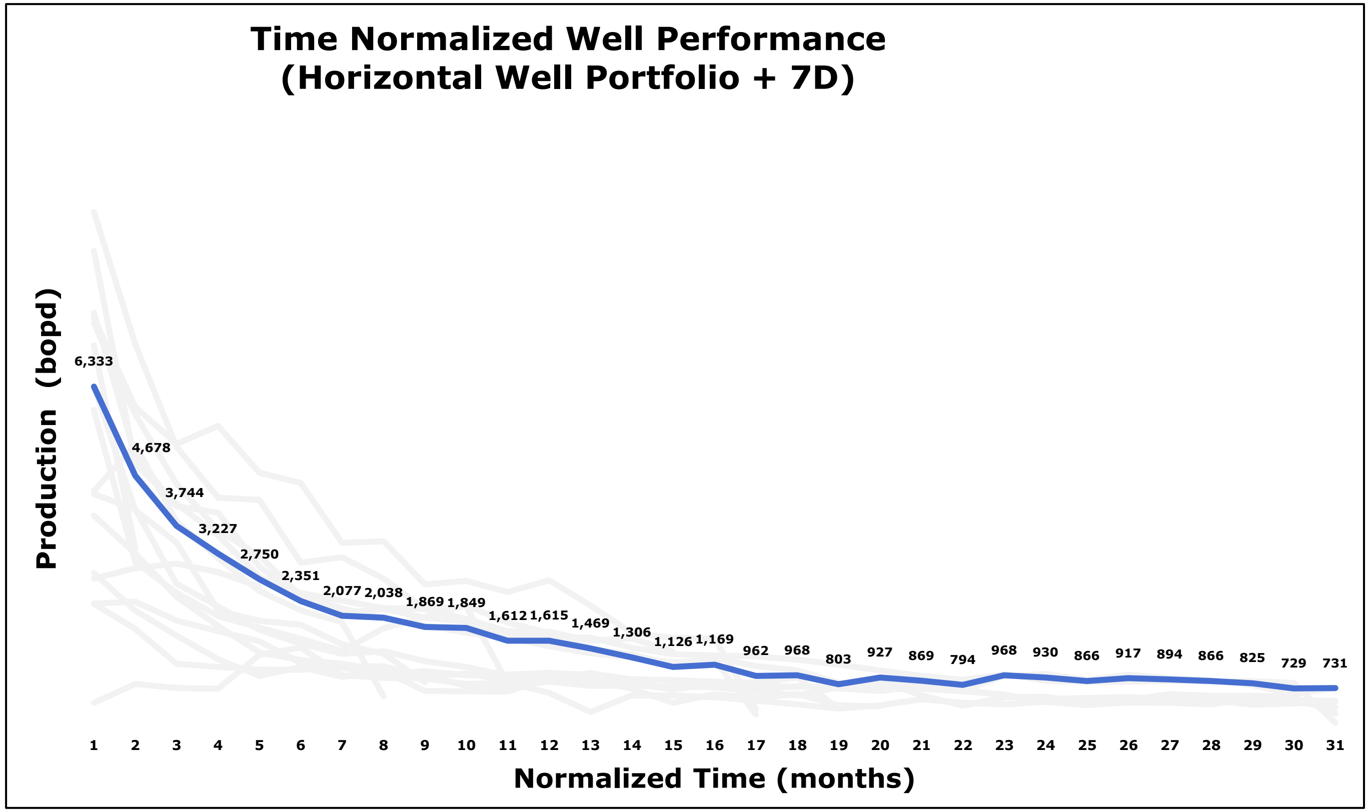
Well	Normalized Time [1] (months)	Cuml. Oil (bbls)	Well Payout (# of times)
1XD	32.4	631,196	>5x
2XD	30.5	928,174	>5x
3D	34.0	849,268	>5x
BN-1	31.0	825,911	>5x
4H	32.3	1,462,984	3.9x
5H	30.1	1,768,788	4.8x
6H	19.9	863,262	2.3x
7D	18.4	780,253	2.0x
8H	16.2	1,838,742	4.8x
9H	16.2	1,359,481	3.6x
10H	14.9	1,393,670	3.6x
11H	10.4	1,426,489	3.6x
13H	8.6	757,847	1.9x
12H	7.4	777,518	1.9x
14H	5.0	506,342	1.2x
15H	1.6	459,690	0.9x
Total		**16,629,615**	

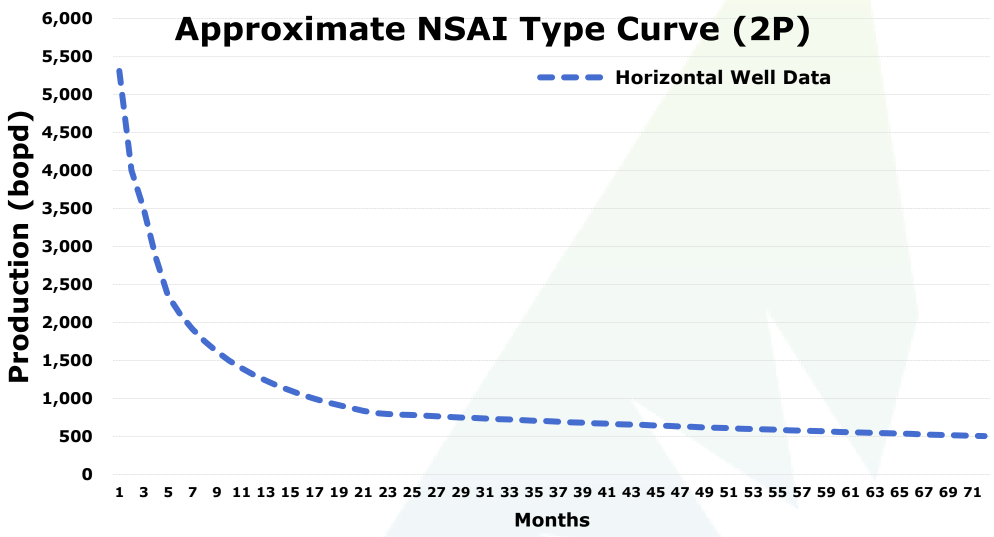
(1) Normalized time – continuous operating time added together excluding downtime

Key highlights

- > 16.6 million barrels produced until Dec 31, 2023
- Wells drilled since 5H are approaching 1.5 years of normalized producing life and have delivered nearly 10 million barrels of oil
- The Company's average producing well has generated 1 million bbls over the first 20 months of normalized time

Type Curve Profile





Summary	Horizontal (based on actual data)	Estimated 2P Ave (NSAI)	Deviated (based on actual data)
IP 90 (bopd)	4,900	3,830	2,019
IP 180 (bopd)	3,400	3,000	1,652
IP 365 (bopd)	2,600	2,290	1,300
EUR (mmbbl)	N/A	4.5	N/A
Capex ($ millions)	$14-$15	$14	$8-$10
Capital intensity (180 days)	$4,200	$4,667	$5,400
Payout ($80 Brent)	60-70 days	170 days	60-70 days
Profit to investment ratio	N/A	>5x	N/A

- 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

Building a Factory to Process Fluids

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

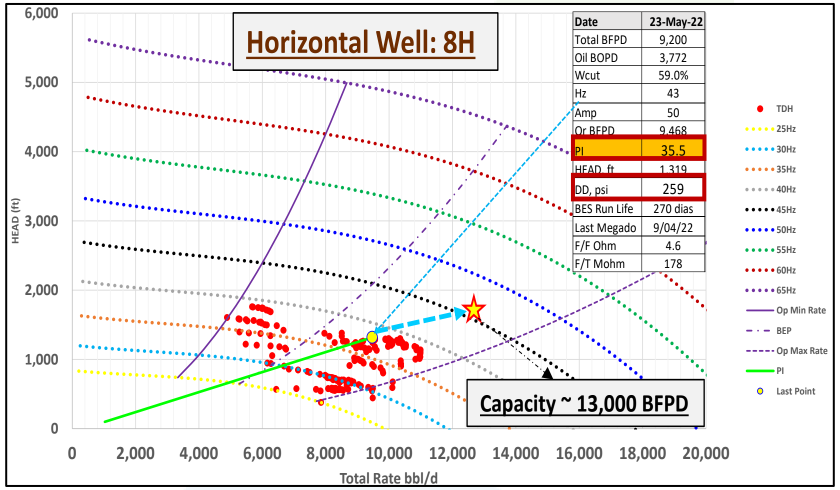
The data to date shows that we can outperform due to:

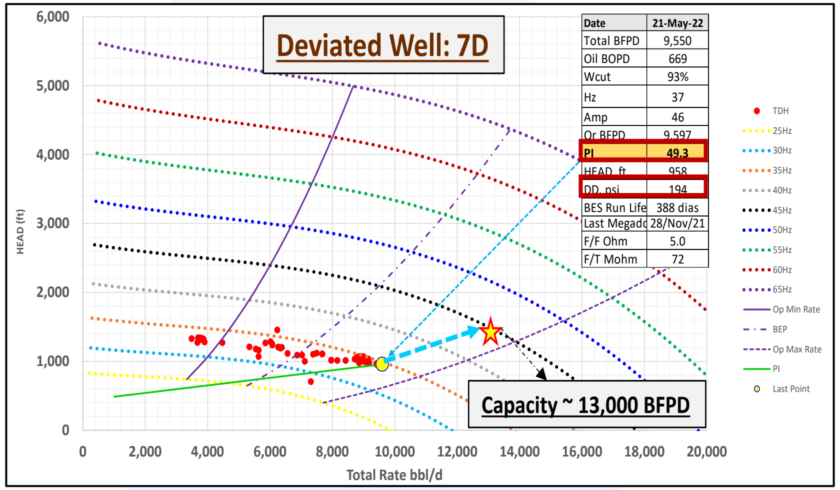
- Well's high productivity index (PI > 30 bfpd/psi)
- Low pressure draw down (DD < 300 psi) that delays water channeling
- Observed draw down is less than 10% of reservoir pressure

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

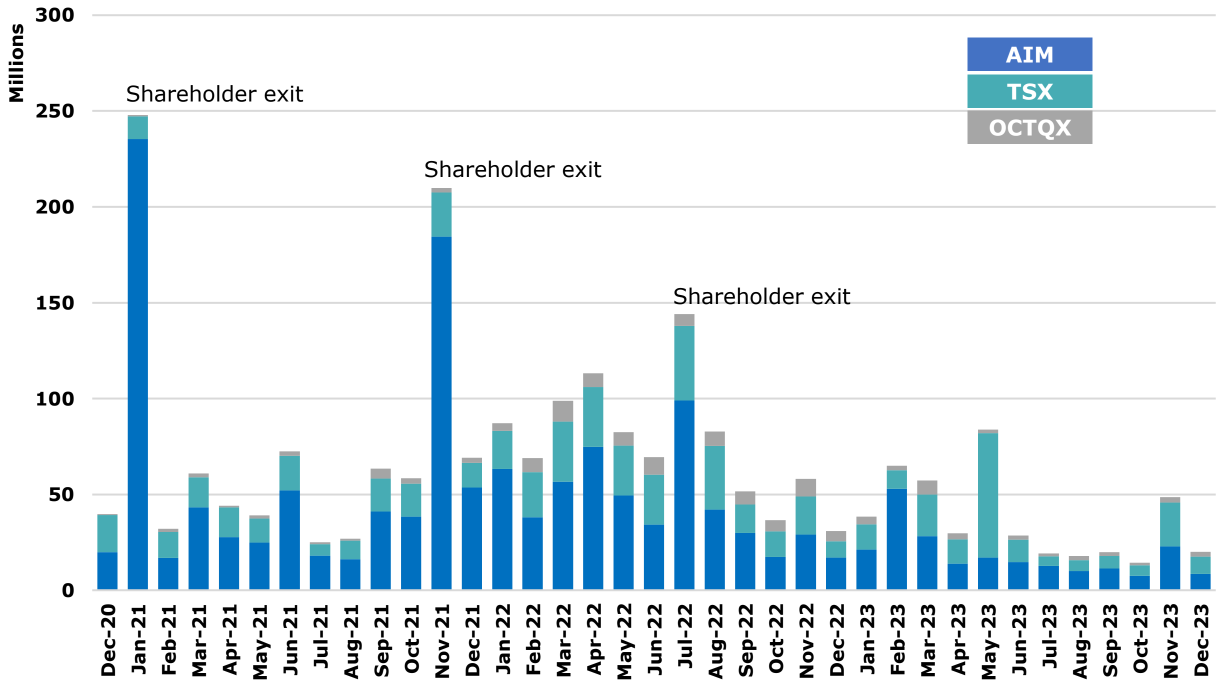
Bretaña could eventually lift 286,000 bfpd in the 2P case, and 377,000 bfpd; which at 10% oil cuts would produce 28,600 bopd and 37,700 bopd, respectively





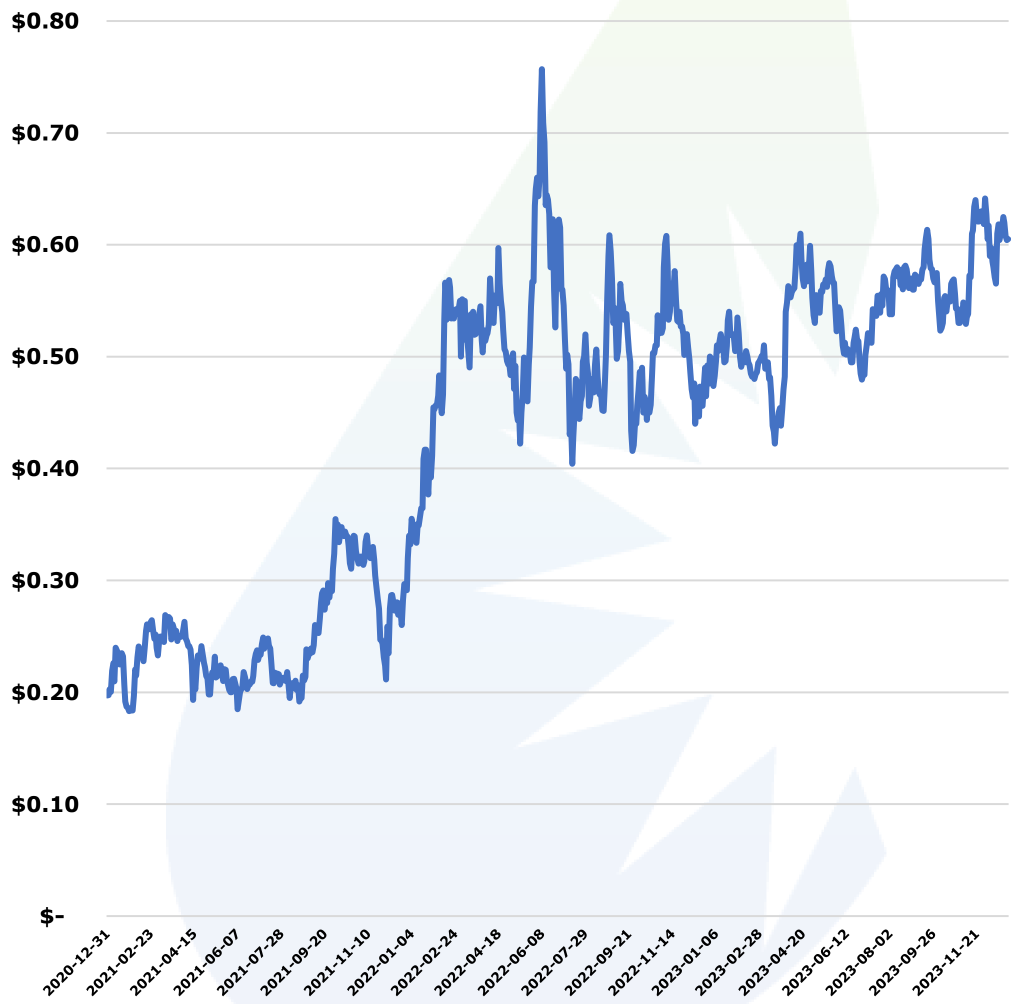
Share Price and Trading Summary

Tal and PTAL Total Trading Volume by Month (millions of shares)



Major shareholders	Shares owned	%
YF Finance	152,879,100	16.7%
Kite Lake	115,513,226	12.6%
Encompass	65,643,213	7.2%
Meridian Capital	54,668,057	6.0%
Fidelity International	42,315,097	4.6%
Total Basic Shares (Feb 5, 2024)	**917,618,900**	

PetroTal Share Price History (USD/share)



See footnotes for additional details and definitions

Extensive Facility Investments in Place

Significant Scalable Infrastructure in Place

- Investment of >$100 million achieves installed processing **capacity of ~24,000 bopd**
- Full field Environmental Impact Assessment (EIA) approved for continued development
  - Common well pad **minimizes footprint (11 hectares, 27 acres)** and increases efficiencies
  - Facility riverside location simplifies logistics
- **Can execute an alternative paced 2P program** with current infrastructure and additional water disposal
- Power generation fuelled by crude oil instead of diesel resulted in **+$100 million NPV(10)**

Facility Build History

Capacity Stage	Incremental Oil bopd	Installation	Incremental Water bwpd
Long-Term Testing Facility	8,000	Dec 2018	10,000
Central Processing Facility #1	8,000	Dec 2019	40,000
Central Processing Facility #2&3	8,000	Dec 2021 & Sept 2023	70,000
Central Processing Facility #3	N/A	Year end 2024	20,000
Total	**24,000**		**140,000**

See footnotes for additional details and definitions

Peruvian Operating Landscape

BBB/BBB+/Baa1 stable outlook (Fitch/S&P/Moody's)

- $4 billion in new notes issued late in 2020
- Country risk rating (EMBIG) of 143, the lowest in all Latin America

Rule of law – concession contracts

- Supreme decree governed contracts carrying through regime changes
- International arbitration resolution

Energy-friendly fiscal policy

- Second largest mining sector in the world
- Growing E&P sector with credible oil service companies in country (Baker Hughes, Petrex, Schlumberger)

Favourable royalty rates and social profit sharing

- ~7% at 20,000 bopd with no price scaling + 2.5% social trust payment
- The Peruvian govt. recently announced a $1.7 billion six-year plan to benefit local communities

Robust quality/sales economics

- Differentials range on heavy oil at $2-$5/bbl
- In country refining capacity to materially increase to over 90,000 bopd in 2022

Supportive Public Ministries

- Los Crudos members captured in fall of 2023 allowing for restart of ONP operations

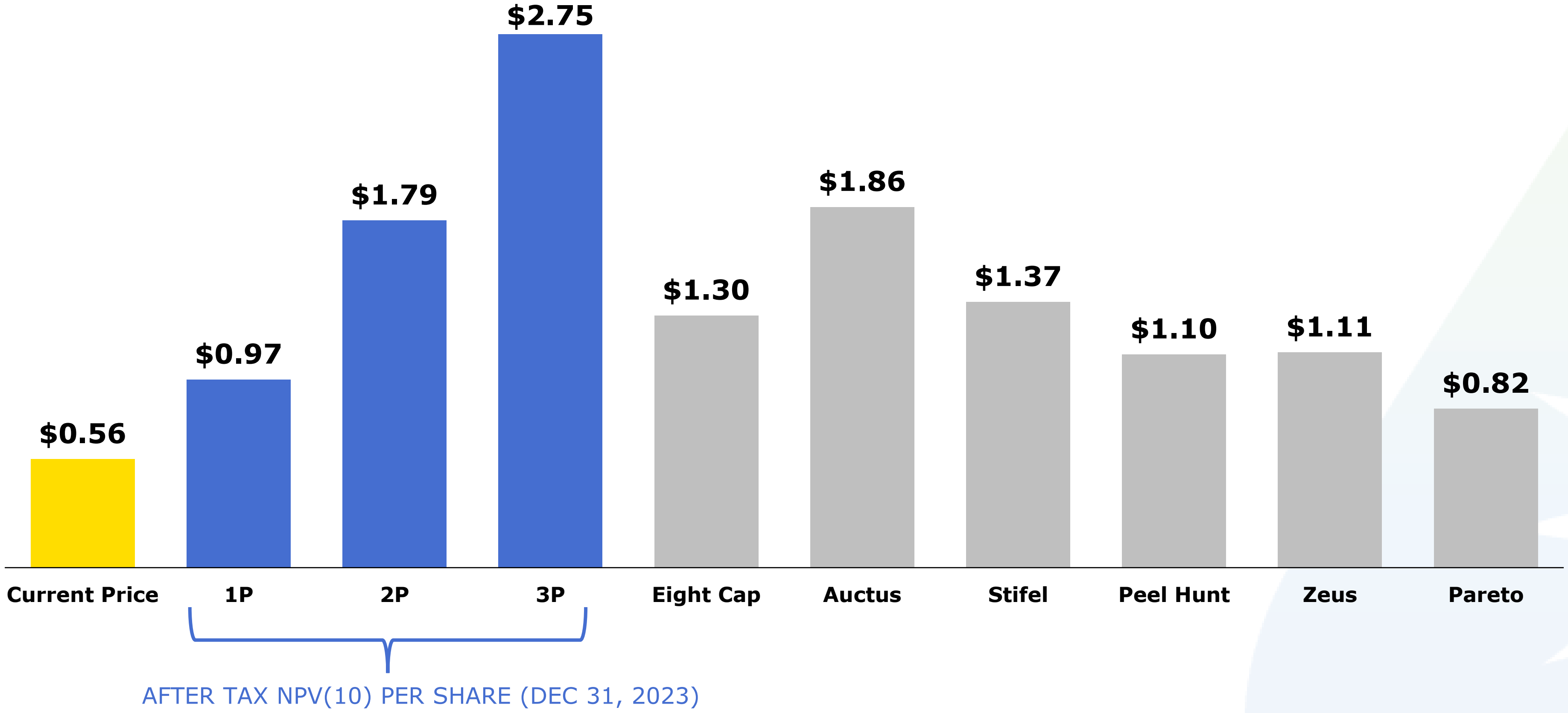
Talara Refinery (upgrade completed)

- $6 billion upgrade completed in Dec 2023
- Materially increasing in country demand for crude and pipeline stability
- Attracting international project capital
- Creating associated commercial opportunities for local producers

See footnotes for additional details and definitions

Analyst Coverage and Relative Target Valuation

TAL valuation and analyst target summary (USD/share)



Key Highlights

- Trading just over blowdown valuation (PDP valuation NPV10/share) per the Dec 31, 2023 year ended NSAI reserve report
- New investors can obtain 1P, 2P and 3P value for free by investing in PetroTal
- Average analyst risked target price at USD$1.26/share

Footnotes

Slide 2
1. Market capitalization as of Feb 1, 2024 using a 1.34 CAD/USD exchange rate
2. Cash less debt = Total cash less short- and long-term debt and lease liabilities
3. NSAI Reserves statement effective date December 31, 2023
4. Reflects contracted offtake of 1,300-2,000 bopd
5. PetroTal also holds a 100% WI in the high impact exploration onshore Block 107
6. See disclaimers – Non Gaap financial measures

Slide 3 / 19
1. Source – 2022 Sustainability Report

Slide 4
1. Production quoted in bopd is average for the year indicated
2. Adjusted EBITDA is NOI (net operating income)less G&A included realized derivative gains/losses

Slide 5
1. All reserve report references are per NSAI Reserves statement effective December 31, 2023. Recovery factors include historical production on top of estimate reserves (ultimate recovery)
2. NSAI reserve production profile does not reflect management's forecast and or budgeted production

Slide 7
1. Soft cap on buybacks refers to an estimated $3 million per quarter of possible buybacks approved by the Company's board
2. Cash sweep refers to the Company's ability to return liquidity to shareholders in excess of approximately $66 million which will also consider future capital and or working capital needs
3. All dividends and buybacks subject to board approval

Slide 8
1. Per the NSAI Reserves statement effective date 31 December 2023
2. AICD – Autonomous Inflow Control Devices

Slide 9/10
1. See disclaimers – Non GAAP financial measures
2. Yearly average sales to Iquitos and Brazil assumed at 1,600 and 14,000 bopd respectively. Sales to OCP and Yurimaguas start in Q3 and Q4 2024.
3. Net Operating Income ("NOI") = Revenue less differentials, transportation fees, commercial fees, royalties, and operating costs
4. After tax free funds flow defined as Adjusted EBITDA less tax less capex before any debt service or other cash costs (see disclaimers – Non Gaap financial measures)
5. Tax includes mandatory 5% employee tax
6. Net true-up revenue and derivative impact not included in after tax free cash flow matrix. After tax free cash flow matrix assumes a run rate Capex of $120 million per year (see table notes)

Slide 11
1. With CPF-2, Bretaña has 90k bbl of crude storage
2. Up to eighteen barges available between 10k and 30k bbls capacity to supply ONP and Iquitos refinery
3. Iquitos and Brazil offtake capacity markets are on a monthly basis, thus allowing for maximum recurring sales of 20,000-24,000 bopd of average production assuming no issues at the Puinahua Channel or in the field (high river levels)
4. In development routes are subject to Petroperu approvals and additional investment in required facility investments

Slide 12
1. Average Brent assumed at. Brazil commercial contract specifies Brent + 3 month pricing. Saramuro commercial contract specifies Brent + 8 month pricing (data not shown because not operational)
2. Production allocations by sales route are estimated and subject to material change depending on market conditions
3. Differential is estimated and subject to changes
4. Normalized EBITDA defined as Netback less G&A excluding material non recurring items (one time items) (See disclaimers non gaap financial measures)
5. 2024 G&A includes additional employee headcount
6. See disclaimers – Non Gaap financial measures

Footnotes, *continued*

Slide 13
1. Management internal forecast subject to change at any time based on changes to internal estimates, capex/development pace and type curves
2. Forecast has additional estimated capital over and above the Dec 31, 2023 NSAI Reserve Report
3. Assumes 3P case goes until 2051 (License extension)
4. Assumes 2P case ends in 2041 (no License extension)

Slide 15-18
1. Production, capex, and cash flow profiles are internal management estimates and have not been confirmed or reviewed by a third party reserve evaluator. They are subject to change at any time
2. See disclaimers (Non Gaap financial measures)
3. Assumes license contract ends in 2041 but is extended for Block 95 and 107 expansion opportunities
4. Assumes $80/bbl on a long term average basis

Slide 19
1. SDG refers to the United Nation's 17 goals for sustainable development (www.sdgs.un.org/goals)

Slide 23
1. Drilling schedule subject to changes based on field operating conditions
2. Dates are estimated
3. "Start date" refers to the start of drilling

Slide 24/25
1. Normalized time adds all hours of well operations together as if the wells were producing continuously to eliminate the impact of social and technical downtime
2. Cumulative NOI (net operating income)(see disclaimers – Non Gaap financial measures) is estimated based on financial statement netbacks at approximately the time of operation

Slide 26
1. Fluid and production figures are management estimates and performance is not guaranteed

Slide 27
1. Shareholders per Feb 5 2024 (AIM rule 26 per PetroTal website)
2. Trading data source per TSX, OTC QX and AIM ending Dec 2023 (1.34 CAD/USD)
3. On Nov 26, 2021 GTE sold an aggregate of 137,093,750 common shares in PetroTal

Slide 28
1. Includes associated infrastructure spending to CPF-2, such as power generation using crude oil as feedstock that helps lower lifting costs
2. When considering the Dec 31, 2023 3P volumes in the reserve report, additional injection capacity equipment is required

Slide 29
1. 2022 E&Y Peru Investment Guide. (Chile 147, Colombia 210, Brazil 255 country risk ratings)

Slide 30
1. CAD/USD = 1.34 and CAD/GBP = 1.7

Disclaimers

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 2024 guidance and budget; future production levels and growth, including 2024 exit production, 2024 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, Adj EBITDA, normalized 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 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.

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, 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 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.

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.

Disclaimers, *continued*

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. Represents 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*

OTHER READER ADVISORIES

FORWARD-LOOKING STATEMENTS: This press release 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 press release contains forward-looking statements pertaining to: PetroTal's intention to continue to develop the Bretana asset; the targeted 20% growth rate from 2023; PetroTal's forecast 2024 funds flow of $160 million; plans with respect to the Company's seismic program in the southern part of Block 95 including with respect to its intended duration and purposes; PetroTal's intentions to continue seeking a partner for co-investment for Block 107 and obtain development permits; the positioning of the Company in 2024; PetroTal's intentions with respect to its return of capital program (including that it will maintain a 12% yield and that the program will continue to consist of dividends at $0.015/share and buybacks of approximately $1.0 million/month 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; expectations surrounding the Company's 2.5% social fund including PetroTal's intended capital allocation of $9 million towards the fund; PetroTal's plans to defer drilling a water disposal well into 2025 and expectations regarding capacity within the Company's existing water disposal wells throughout 2024; estimated returns from the Company's 2024 dividend and buyback plan; drilling plans including with respect to the commencement and completion of drilling wells 17H, 18H, and 19H; intentions regarding well 17H, including in respect of timing and budgetary expectations; estimated payback from well 16H and the timing thereof; PetroTal's plans to continue to allocate capital to its long term preventative erosion control program; PetroTal's 2024 budget for the erosion control project and plans in respect thereof; the 2024 Capex budget; plans with respect to PetroTal's 2024 facilities program including anticipated key projects and expenditures in respect thereof; and PetroTal's expectations regarding 2024 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 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 necessary permits, 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. 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. 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, 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), 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 and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; changes in the financial landscape both domestically and abroad, including volatility in the stock market and financial system; and wars (including Russia's war in Ukraine, the Israeli- Hamas conflict and the Houthis attacks in the Red Sea). 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 are available 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.

SHORT-TERM RESULTS: References in this press release to peak production rates, current production rates, initial 14-day 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. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for PetroTal. The Company cautions that such results should be considered to be preliminary.

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").

SPECIFIED FINANCIAL MEASURES: This press release 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. 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. Please refer to the MD&A for additional information relating to specified financial measures.

FOFI DISCLOSURE: This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about PetroTal's 2024 fully funded budget and guidance, prospective results of operations, estimated growth rate, 2024 targets (including production and sales targets), 2024 average sales target of 17,000 bopd, initial 14 day production rate for well 16H of 6,000 bopd, production capacity, forecast funds flow of $160 million, free funds flow of $25 million and the components thereof including dividends and share buybacks and the targeted 12% return therefrom as well as derivative true up payments, erosion control and community expense, revenue, capex, average contracted brent, EBITDA, adjusted EBITDA, estimated closing 2024 cash and components thereof including estimated net working capital movements, forecast 2024 funds flow, free funds flow, free funds flow (after capex), payout of wells, estimated payback, netback, OPEX and the components thereof, G&A expenses and the components thereof, tax rates, Capex, royalty rates, future investments and capital allocation (including capital deployed towards any government and community amounts in 2024 such as the 2.5% social fund), net operating income, shareholder returns 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 press release was approved by management as of the date of this press release and was included 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 press release, 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 press release should not be used for purposes other than for which it is disclosed herein. All FOFI contained in this press release complies with the requirements of Canadian securities legislation, including NI 51-101. 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.

Disclaimers, *continued*

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
bopd	barrel of oil per day
k bopd	Thousand barrel of oil per day
F&D	Finding and development costs
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 derivative adjustments; EBITDA is Adj. EBITDA prior to derivative impacts
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


PetroTal
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