PetroTal en el Lote 95

Bretaña Norte:
de 39.8 a 96.7 mmbbls
de reservas 2P

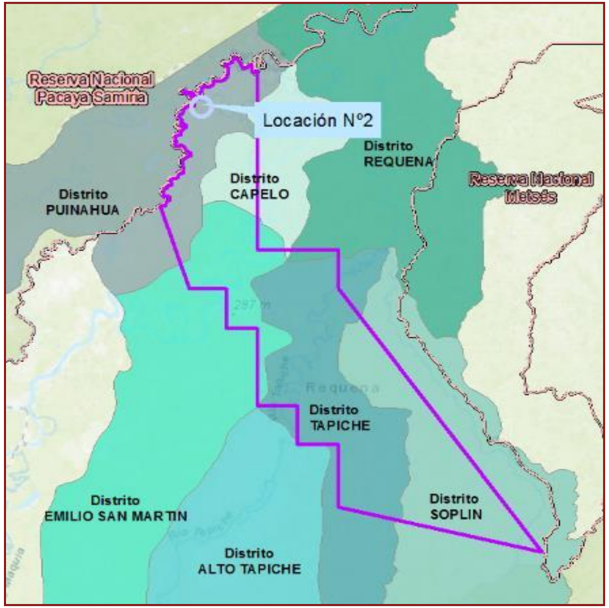
AMECOP

Oct. 23

PetroTal

LIDERADA Y OPERADA POR PERUANOS

Ubicación

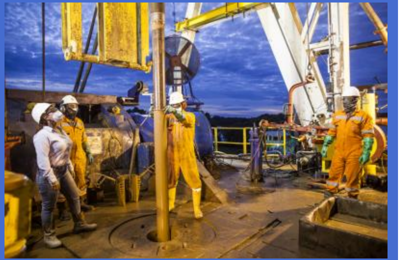


LOTE 95

- Hectáreas: **345 282** (853 210 acres)
- Región: Loreto
- Provincia: Requena
- Distritos (07): Puinahua, Capelo, Soplin, Emilio San Martín, Tapiche, Alto Tapiche y Requena.
- Zona de Amortiguamiento de la Reserva Nacional Pacaya Samiria
- **Yacimiento Bretaña Norte: Se ubica en el distrito de Puinahua**

Nuestra operación: Locación 2A

Seguridad con la que trabajamos



Cuidado y respeto del ambiente

Aliados del desarrollo

Locación 2A: 11.4 ha aprobados por EIA & ITS

Nuestra operación: Locación 2A

Resumen Técnico	
Prod. actual (al 22/10/23)	~21,500 bopd
Prod. potencial (al 22/10/23)	~24,000 bopd
Prod. Promedio 2023 (al 22/10/23)	13,750 bopd
Prod. Acumulada @ Dic 2022	11 mmbbls
EUR (Acum + Reservas 2P)	108 mmbbls
Pozos productores perforados	16
Pozos inyectores perforados	03
2P / 3P futuros pozos productores	29 / 36

Resumen Comercial	
Capacidad de almacenamiento	90,000 bbls
Capacidad de ventas a Iquitos	1,300 – 2,000 bopd
Capacidad de ventas a Brasil	14,000 – 18,000 bopd
Capacidad de venta a ONP	0 - 25,000 bopd
CPF-2 Capacidad de procesamiento	24,000 bopd

Campo Bretaña Norte (2023)

Nuestra historia como PetroTal

2017/2018

0 to 958 bopd

Activo de origen y capitalización inicial

- Adquisición a Gran Tierra en Perú
- Pozo reactivado: 1XD-ST2
- Producción de salida: 1,000 bopd
- Mejora de la infraestructura para procesar 5,000 bopd

2019

4,131 bopd
+ 330% growth

Demostrada credibilidad operativa

- 5 pozos adicionales y 1 pozo de inyección de agua.
- Puesta en marcha del CPF-1.
- 13,300 bopd al cierre de 2019
- Acuerdo de compra garantizado con Petroperú

2020

5,675 bopd
+37% growth

Recalibración y alineamiento debido a la Covid-19

- Perforación de pozo 6H a pesar de inicio de pandemia
- Tercera ruta al mercado a través de Brasil
- Estrategias de inversión flexibles para conservar liquidez y producción.

2021

8,956 bopd
+58% growth

Excelencia operacional
(20,000 bopd logrados)

- Cuatro pozos de desarrollo
- Estrategia acelerada de disposición de aguas
- Puesta en marcha del CPF-2
- Emisión de bonos por US$ 100 millones a tres años
- A mediados de diciembre se alcanzó 20,000 bopd

2022

12,200 bopd
+36% growth

Flujo de caja libre

- Mayor productor de petróleo en Perú
- Incremento del precio de la acción alcanzado: x3
- Tercera ruta de ventas establecida (Brasil)

- Cuatro pozos más en producción
- US$ 198 millones aprox. de flujo de caja libre estimado antes del servicio de la deuda
- Esfuerzo por amortizar la deuda a principios de 2023
- CPF-3 y otras obras de ampliación

Restablecimiento de la política de devolución de capital

2023

14 000 -15 000 bopd
+19% growth

Devolución de capital

- ~>14 millones de barriles producidos (al Q2-2023)
- Comienza el programa de dividendos y recompra

- Comercialización a nuevos mercados
- Perforación de 04 pozos desarrollo sin sobrecapitalización
- Retorno, dividendos y programa de recompra iniciado
- Devolución de un importante flujo de caja libre a los accionistas.

Desarrollo del campo Bretaña Norte

Oct. 2018

Mar. 2019

Mar. 2020

Jun. 2021

Jun. 2022

Abr. 2023

2017

- Dic. : Inicio de actividades de PetroTal Corp. en Perú

2018

- Jun. : Reactiva producción del pozo 1XD-ST2
  Facilidades de producción del Pre-early (Capacidad 1 kbopd)
- Nov. : Pruebas largas de producción (periodo retención)
  Facilidades de producción del Early (Capacidad 5 kbopd)
- Dic. : Declaración de comercialidad (28.12.2018)
  Fase de explotación. Contrato de Licencia hasta 30-Nov-2041.
  Piloto de venta de crudo hacia refinería Conchán – Lima.

2019

- Feb. : Perforación del pozo exploratorio 2XD
- Abr. : Inicia la perforación de 03 pozos desarrollo y 01 iny
- Jun : Piloto de venta de crudo hacia Bayovar vía Yurimaguas.
- Dic. : Comisionamiento de facilidades de producción CFP1 (cap. 16 kbopd)

2020

- Feb. : Perforación del pozo desarrollo 6H.
- May. : Cierre de operaciones por fuerza mayor pandemia
- Ago. : **Conflictividad social**
- Oct. : Reactivación de producción. **ONP paralizado**
- Dic. : Piloto de venta de crudo hacia Brasil

2021

- **Ene. : Planta de Generación con Crudo (ahorro significativo en Opex)**
- Mar. : Inicia la perforación de 04 pozos desarrollo y 01 inyector disposal.
- Dic. : Comisionamiento de facilidades de prod. CFP2 (cap. 24 kbopd)

2022

- Feb. : Primer productor de petróleo en el Perú
- Mar. : **Conflictividad social**
- May. : Inicia la perforación del pozo 11H
- Ago. : Inicia la perforación del pozo 13H
- Oct. : Inicia la perforación del pozo 12H
- Dic. : Inicia la perforación del pozo inyector 4WD

2023

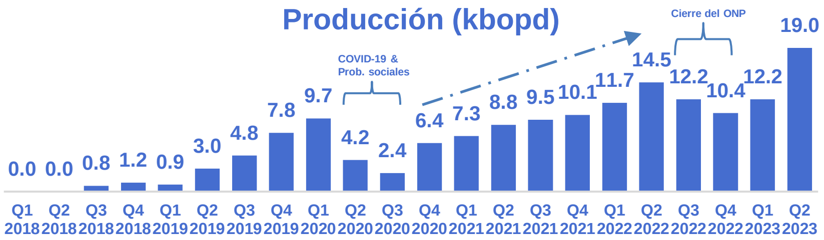
- Feb. : Inicia la perforación del pozo 14H
- Abr. : Inicia la perforación del 15H
- Oct. : Termina la construcción de la nueva Plataforma L2 Oeste

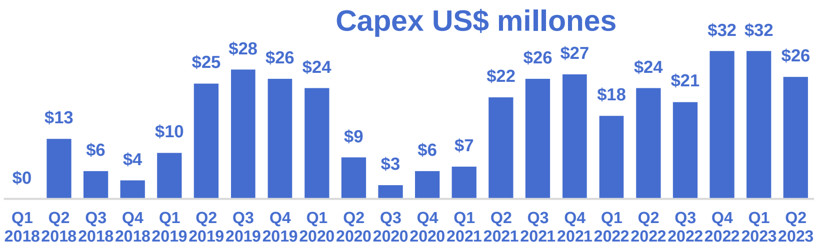
Desarrollo del campo Bretaña Norte

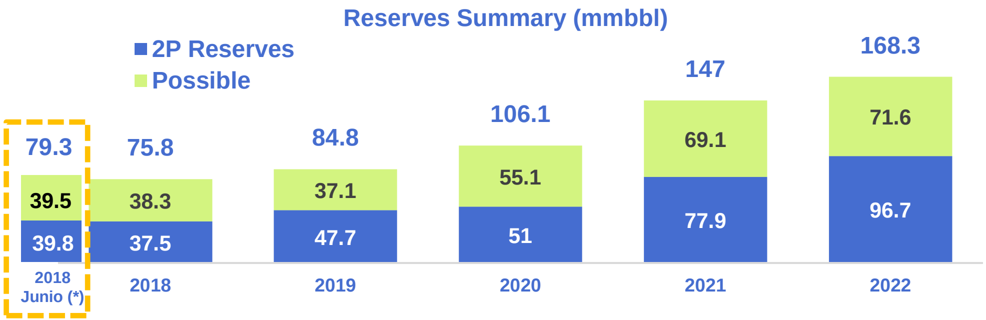
PetroTal

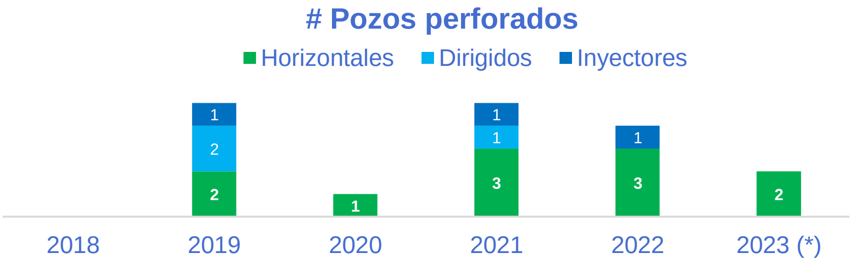
- **14.2 M de barriles producidos aprox. hasta 2T 2023**
- 7 trimestres consecutivos de crecimiento de la producción (4T 2020 – 2T 2022)
- Récord de producción diaria de 26 000 bopd aprox. (2022)

- US$ 390 millones aprox. en inversiones desde su creación para alcanzar una capacidad de producción de 20 000 bopd.
- Alta rentabilidad de los pozos (pagos a 30-60 días con US$ 14 millones/pozo)









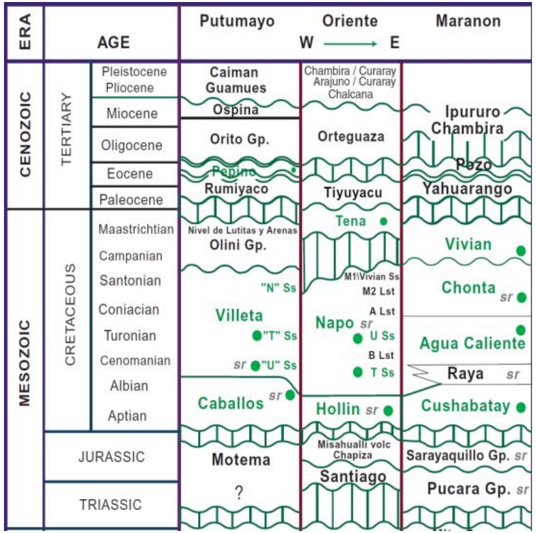
(*) A Set. 2023

- (*) Junio 2018: Asumían un factor de recuperación de ~12 % (2P) y ~16% (3P) según NSAI (31.12.2017)
- Dic 2022: Factores de recuperación 2P (24%) y 3P (28%), que se han conseguido en 04 años de operación.
- Los pozos 2P contabilizados son 29, lo que permite programas de desarrollo plurianuales continuos.
- 2022 2P EUR (recuperación final) por encima de 100 mmbbls.

17 Pozos perforados por PetroTal

- 11 Pozos productores horizontales.
- 03 Pozos productores dirigidos.
- 03 Pozos inyectores disposal

Geología regional

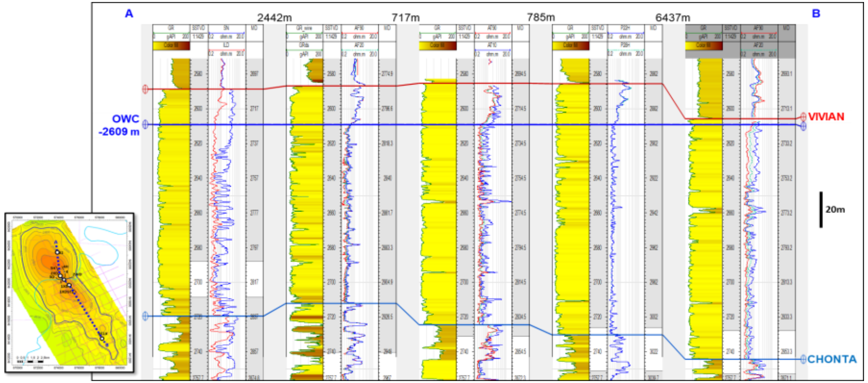


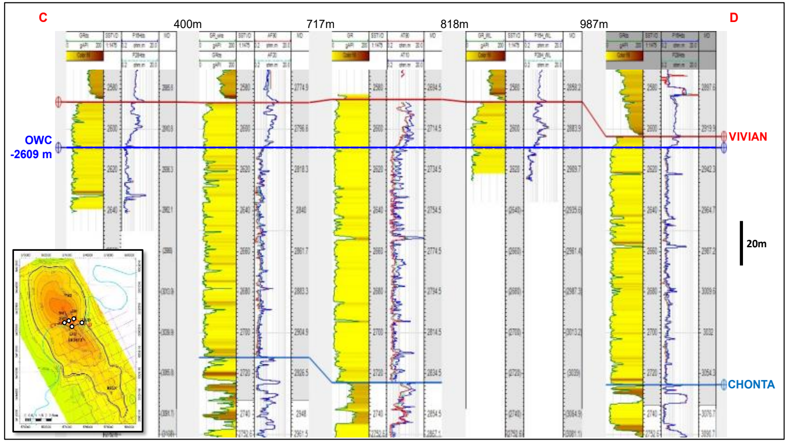
Aspectos técnicos Bretaña Norte	
Presión de reserv. @ WOC	3,942 psi
Temperatura	214 ^{0}F
API (PVT/Assay)	18.6 / 19.2
GOR	25 scf/bbl
Presión burbuja	320 psi
Oil FVF	1.056
Viscosidad @Tr.	23.6 cp
Densidad	0.895 g/cc
Permeabilidad	2,000 md
Porosidad	23 %
Saturación	38 %
Espesor neto	59 feet

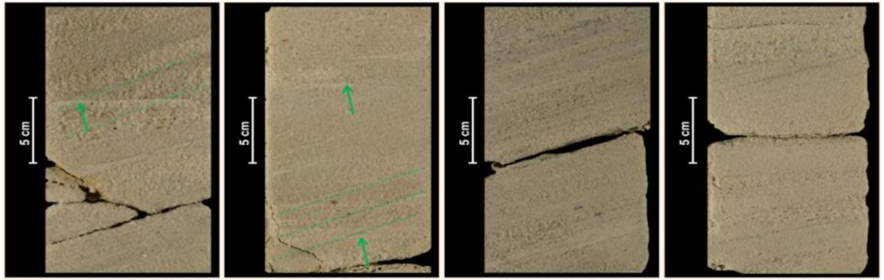
Cuenca Marañón: Puntos Clave

- Es la extensión sur de la cuenca de antepaís más grande que cubre el Putumayo (Colombia) y el Oriente (Ecuador
- Tiene una pila de sedimentos mayor a 6,000 m en el depocentro. Las rocas más antiguas reportadas son de edad Devónico, dentro de grabens
- El campo Bretaña es una estructura sutil ubicada en el margen sureste de la cuenca.
- Aunque la cuenca tiene dos sistemas petroleros probados, solo uno está presente en el Lote 95 (areniscas Vivian del Cretácico cargadas por la roca generadora del Jurásico Pucará)

Geología y petrofísica de Bretaña Norte







A.- Depth: 2900.80/2901.00 m. Nearest sample 3-8-20 P: 2901.02 m. Ø= 30.96%, K= 9585.64 mD

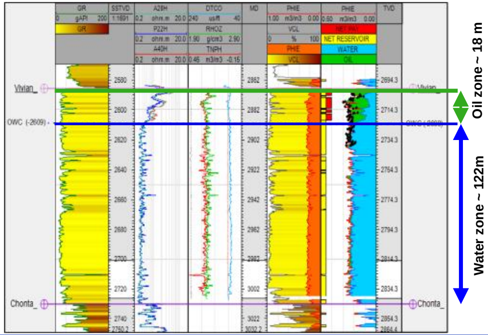
B.- Depth: 2902.88/2903.08 m. Nearest sample 3-10-26 P: 2902.85 m. Ø= 26.71%, K= 6105.82 mD

C.- Depth: 2903.60/2903.80 m. Sample 3-11-31 P: 2903.70 m. Ø= 26.37%, K= 6553.69 mD

D.- Depth: 2904.98/2905.18 m. Sample 3-12-37: 2905.10 m. Ø= 27.06%, K= 6487.75 mD

Areniscas cuarzosas de grano medio con estratificación cruzada plana.

- **Formación Vivian (productora de petróleo)**: Depósitos fluviales que consisten principalmente en un complejo de canales en un sistema fluvial entrelazado, con poca o ninguna evidencia de depósitos simples
- Los núcleos extraídos muestran que la saturación de agua irreducible es más baja de lo que se pensaba = **más petróleo móvil.**



RESERVOIR ZONE:
- GROSS = 144 m
- NET RESERVOIR = 135 m
- Phie (avg) = 23 %
- Vclay (avg) = 7 %
- K core (avg) = 1000 mD.

PAY ZONE:
- NET PAY = 18 m
- Phie (avg) = 24 %
- Vclay (avg) = 7 %
- Sw (avg) = 30 %
- OWC @ -2609 m.

CUTOFF:

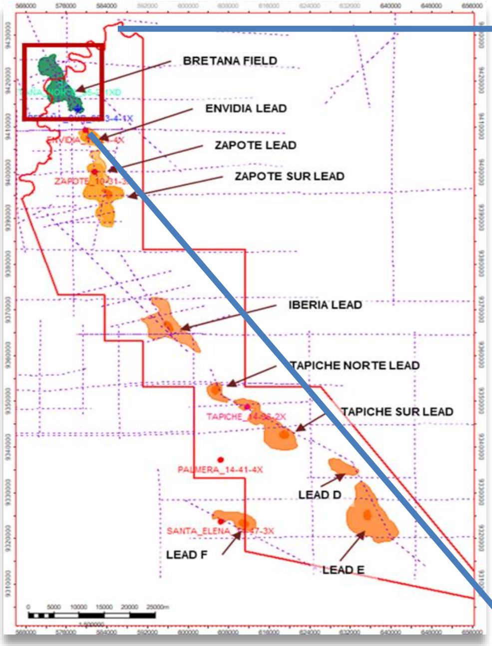
Phie ≥ 12 %
Vclay ≤ 30 %
Sw ≤ 60 %

Yacimiento de arenisca de muy buena calidad con heterogeneidades locales..

OWC basado en MDT y análisis de registros: -2609 mTVDss.

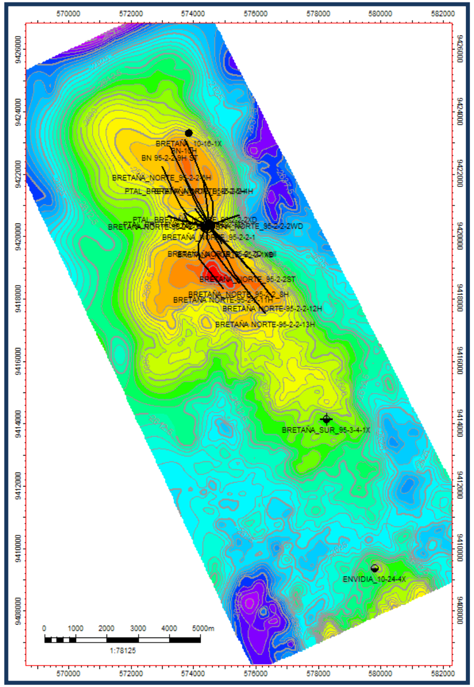
Modelo geológico del Lote 95

Lote 95

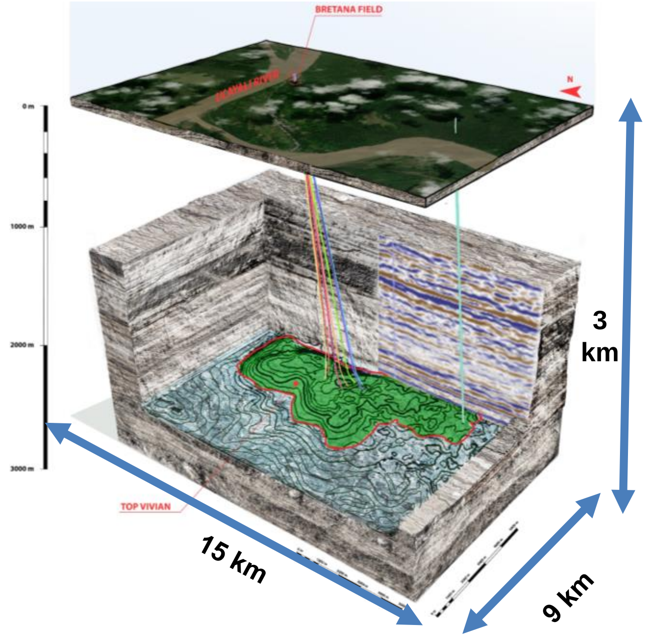


Campo Bretaña Norte - Locación 2A

Tope Formación Vivian



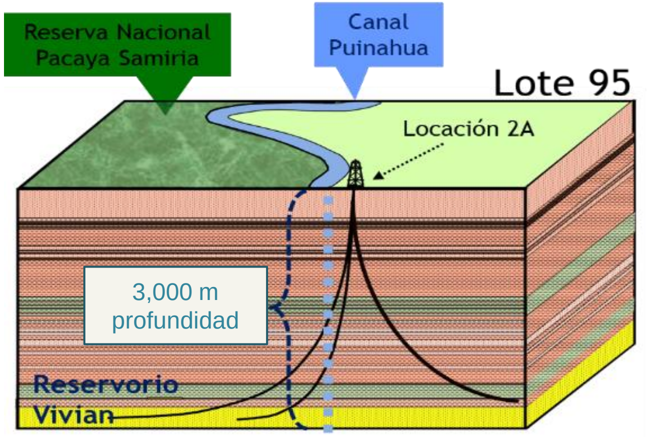
Intersección con topografía superficial Río Ucayali (Canal del Puinahua)



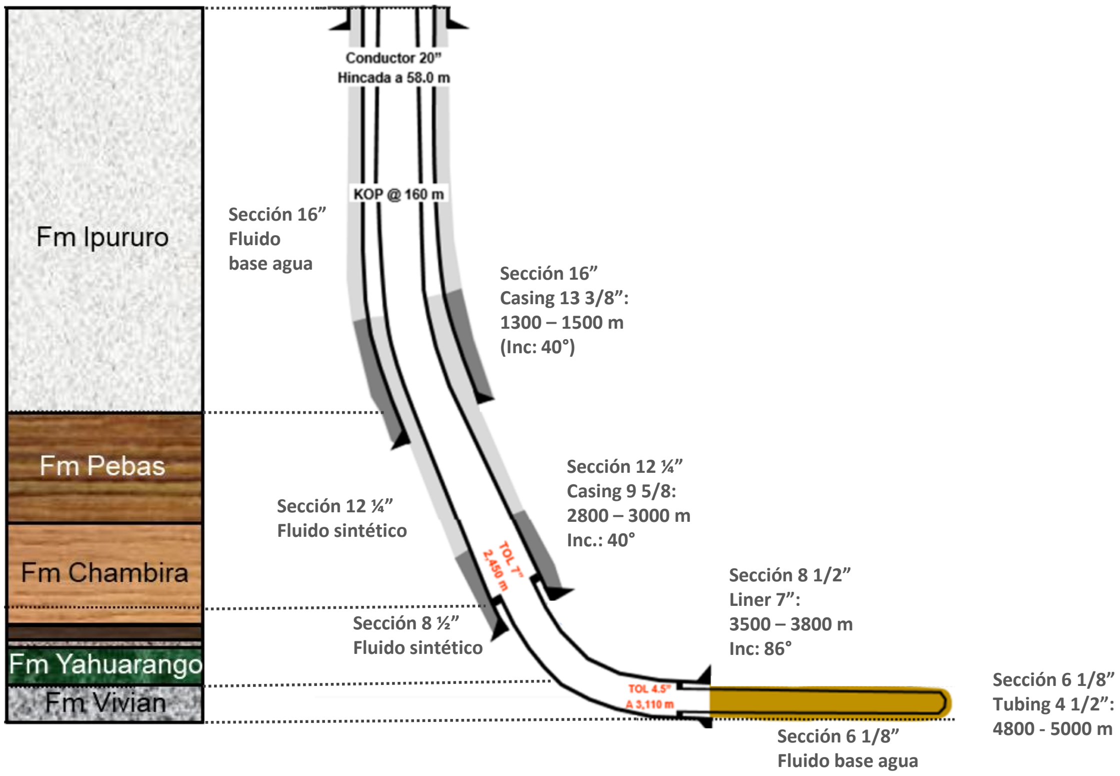
- La explotación de petróleo se hace a través de pozos dirigidos y horizontales en la formación Vivian a +/- 3 Km de profundidad vertical.
- 08 Leads exploratorios. Actualmente en trámite un EIA para la ejecución de 94 líneas sísmica 2D en varios de los leads del Lote 95.

Mínimo Impacto por la Perforación horizontal

Explotación de petróleo se hace a través de pozos dirigidos y horizontales en la formación Vivian a +/- 3 Km de profundidad vertical.



La perforación de pozos horizontales en el Lote 95 **no genera impactos** en la Reserva Nacional Pacaya Samiria.

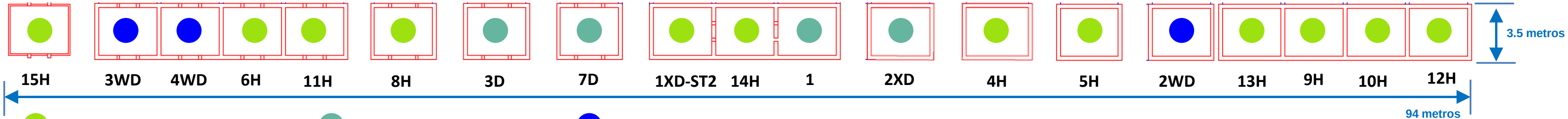


Minimizamos impactos al perforar en un solo PAD

Campamento

Plataforma L2

Oficina Company Man

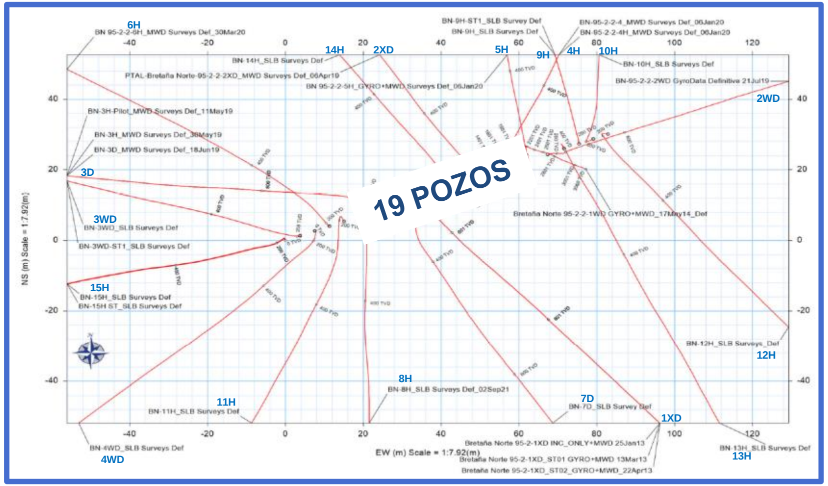


12 Pozos Horizontales

04 Pozos Dirigidos

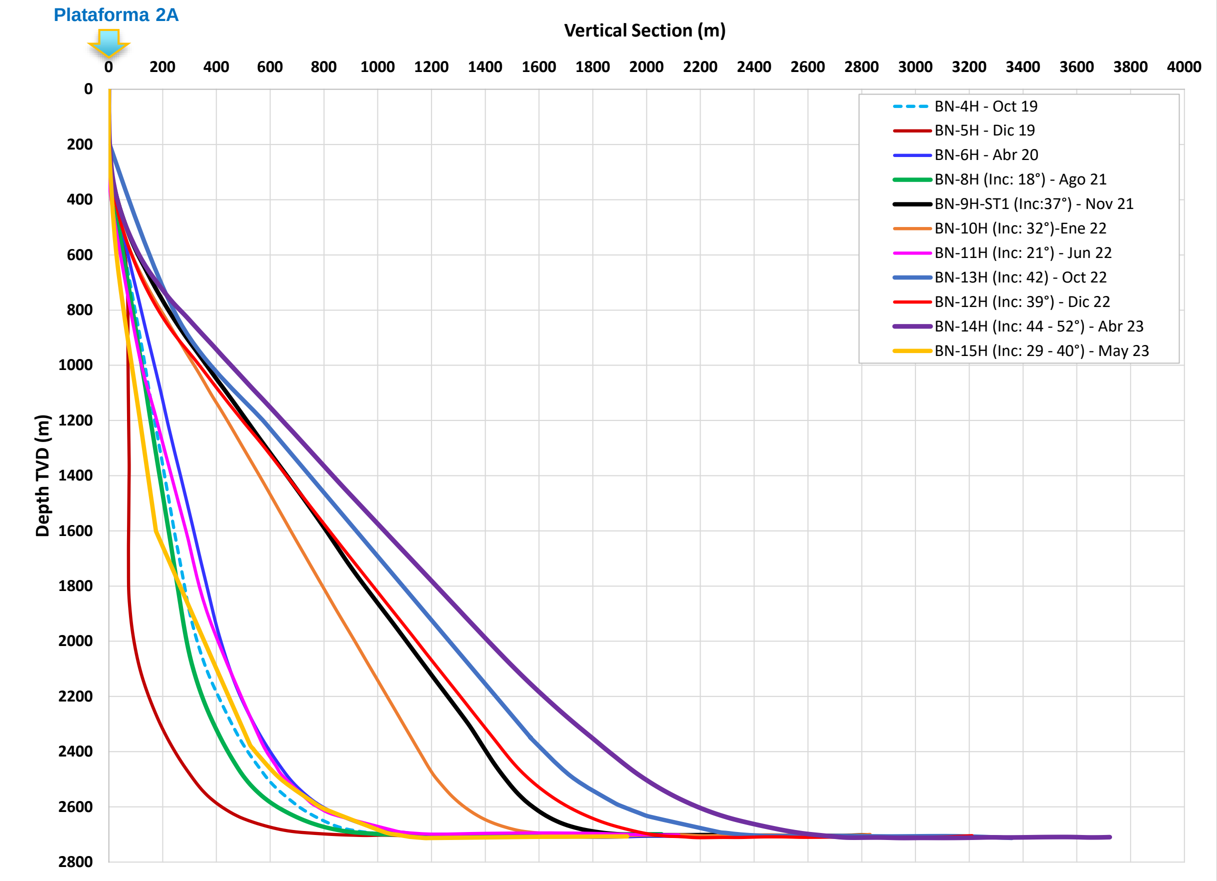
03 Pozos inyectores

Taladro T- 412, 2,000 hp.
Contratista: KCA DEUTAG



Diseño avanzado anticolisión en perforación direccional

Record en perforación horizontal en el Perú



WELL	MD, m	TVD, m	Vertical Section, m	Longitud Horizontal, m
4H	3,561	2,704	1,412	467
5H	3,937	2,706	1,630	863
6H	4,385	2,710	2,394	1,178
8H	4,200	2,677	2,056	1,137
9H	4,368	2,702	2,818	971
10H	4,542	2,700	2,831	1,202
11H	4,301	2,701	2,120	1,125
13H	4,864	2,713	3,359	1,152
12H	4,740	2,794	2,589	1,178
14H	5,137	2,710	3,723	1,133
15H	4,560	2,707	1,927	1,130

Pozos horizontales cada vez de mayor inclinación inicial.
Record longitud horizontal perforada 1,202 m

Geonavegación en las mejores arenas productoras

Imágenes

Porosidades

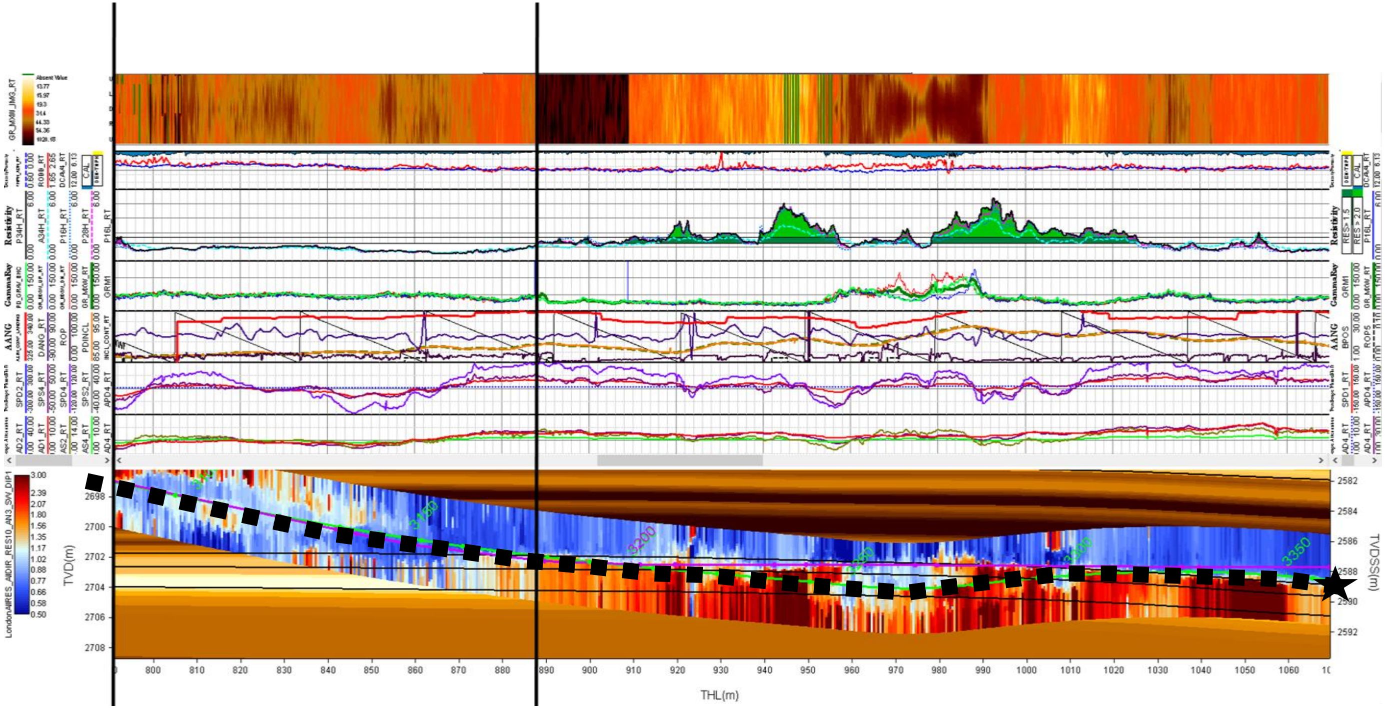
Resistividades

GR

Perforación

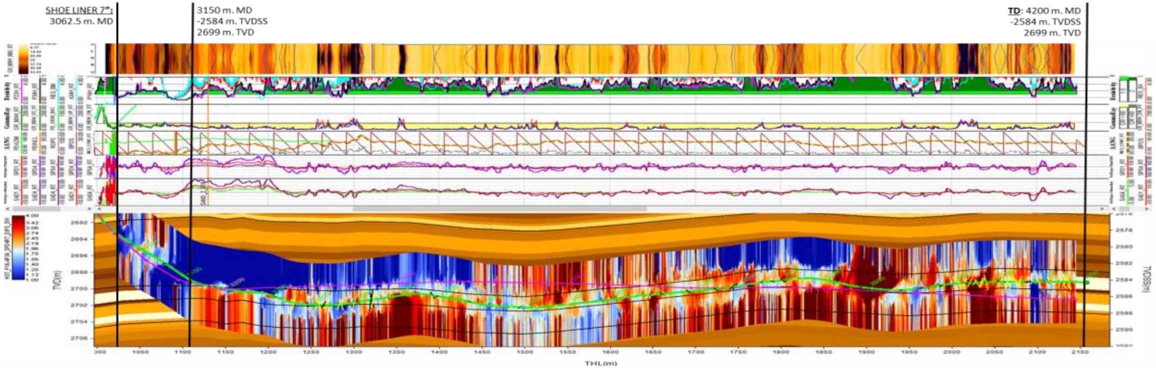
Curvas azimutales

Inversiones



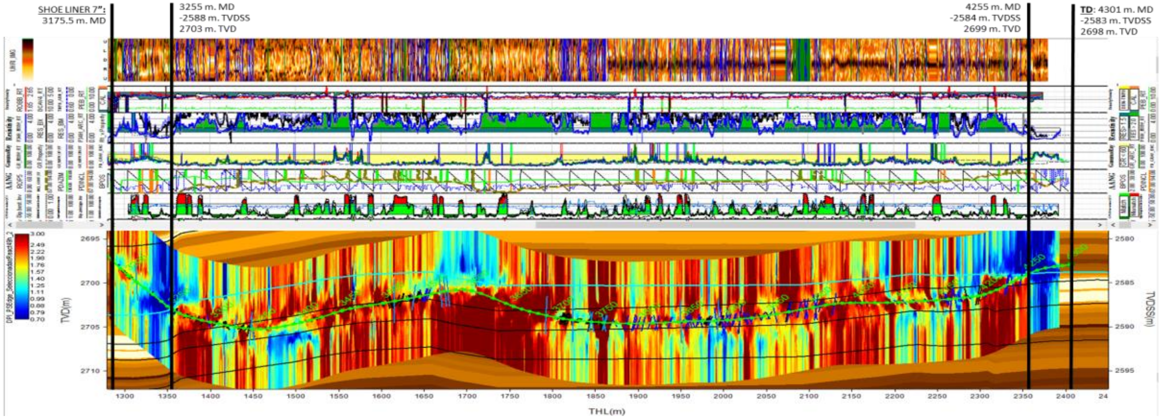
Incorporando últimas tecnologías en geonavegación

2019-2021



INTERVALO DE NAVEGACIÓN (m TVDSS): -2584 / -2587

2021-2022



INTERVALO DE NAVEGACIÓN (m TVDSS): -2583 / -2590

Optimización en la completación de pozos horizontales

Menos intrusión de agua ➡ Mayor recuperación de petróleo ➡ Menos reinyección de agua ➡ Menos consumo de energía ➡ Menos huella de carbono.

- Control de arena a través de la instalación de mallas de alta performance
- Restricción natural del ingreso del agua por tecnología de punta "AICD/AICV"

2019-2020

AICD disco

2021

AICD Hidrociclón

2022

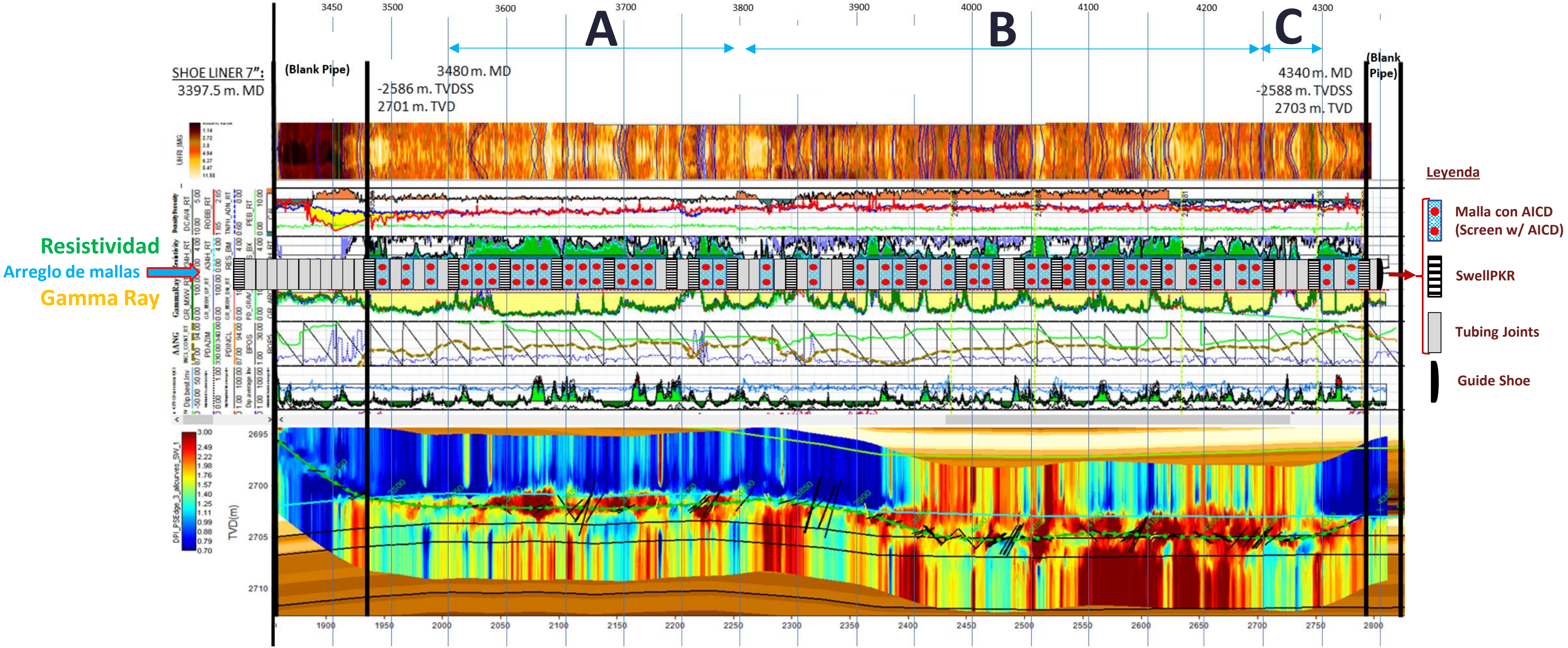
AICV

Innovando la industria

TECNOLOGÍA AICD

La implementación de la tecnología AICD consiste en la instalación de un conjunto de válvulas a lo largo de la zona productiva horizontal del pozo y que, mediante un principio físico de cambio de presión, logran de manera autónoma restringir la entrada de agua pero permiten la producción de petróleo.

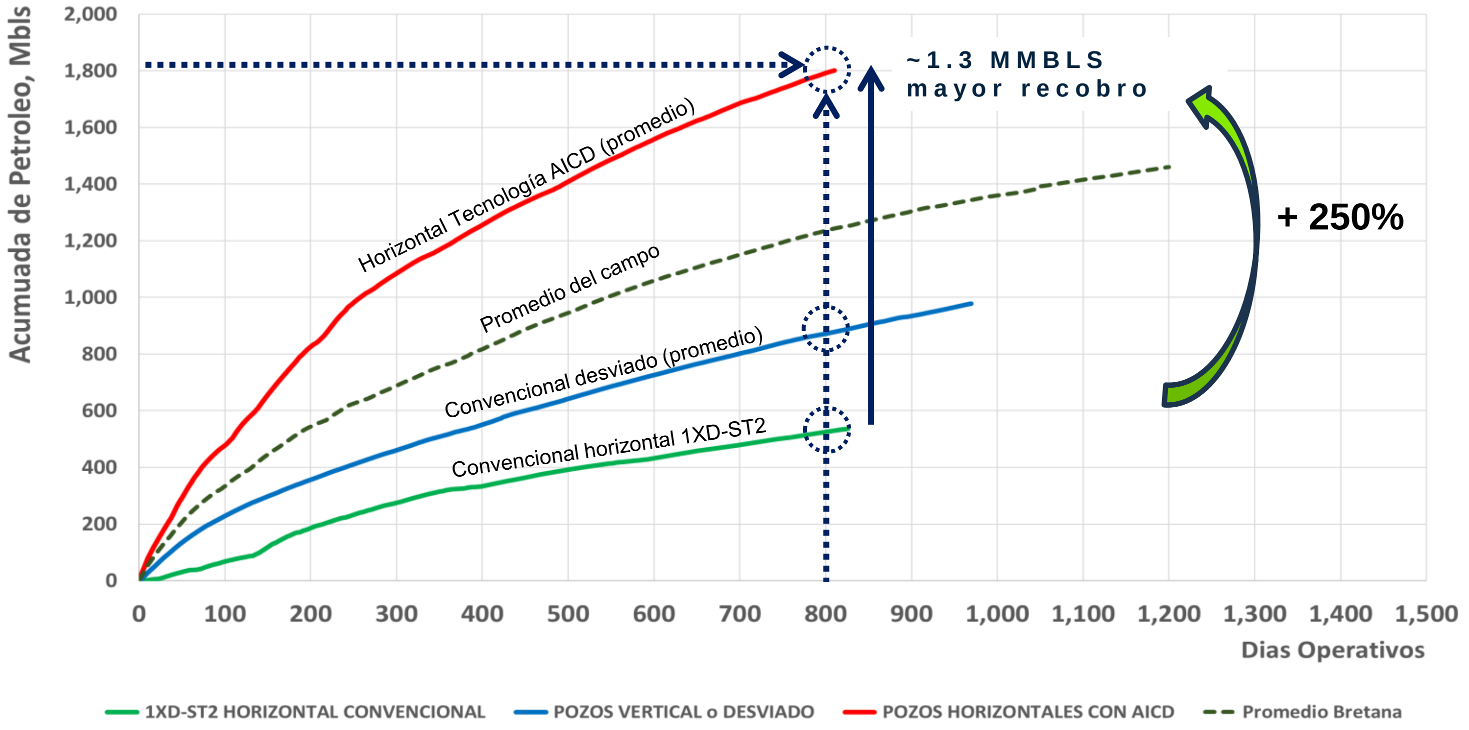
Optimización en la completación de pozos horizontales



- **Compartimentalizar es fundamental para optimizar trabajo de AICDs.**
- **Se procura mantener separadas las zonas de alta resistividad (A) (alta saturación oil – alta permeabilidad) con las de mediana (B).**
- **Se aísla (sin mallas, C) las zonas sin ningún potencial debido al peligro de producir arena muy fina.**

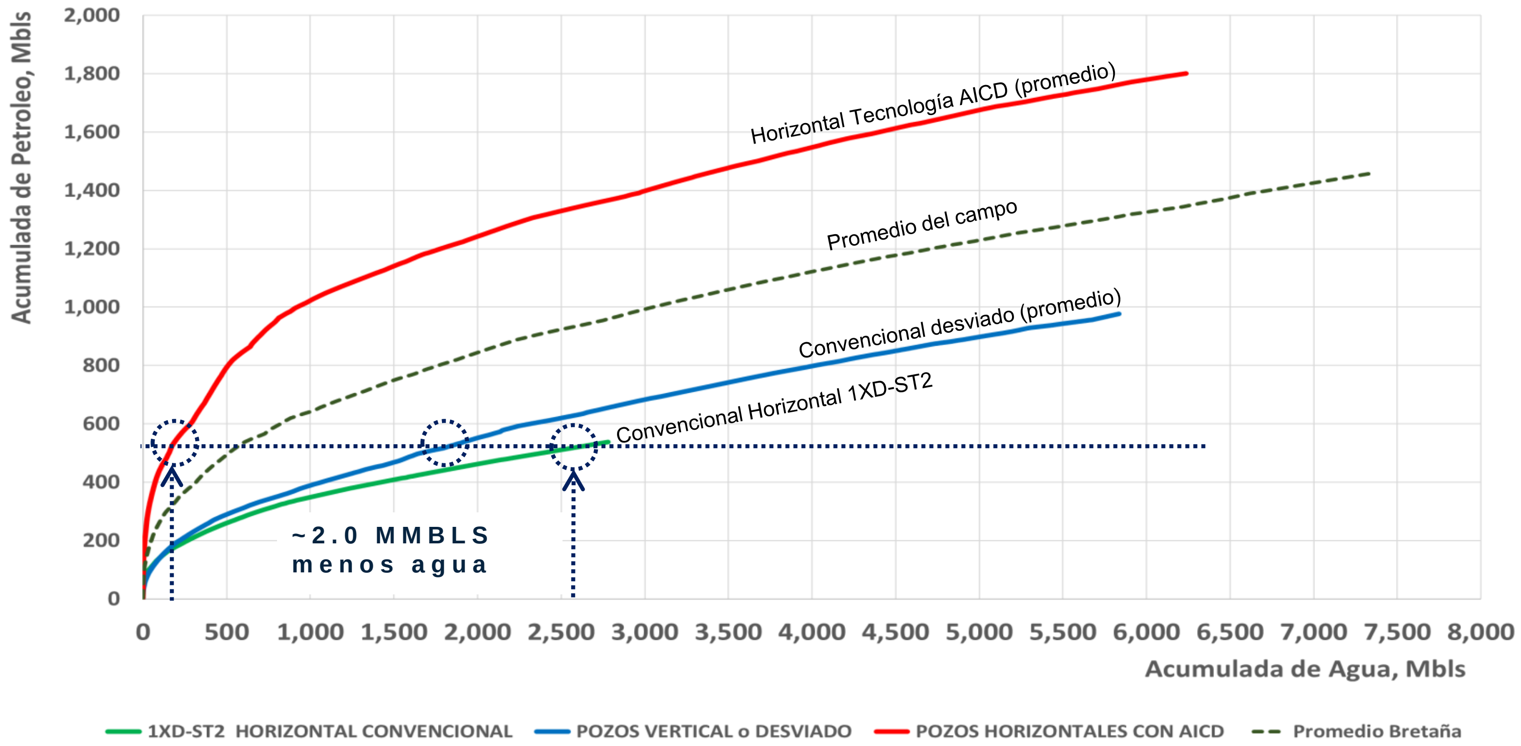
Maximizamos la recuperación de reservas

Incremento significativo en la producción de Petróleo



Minimizamos la reinyección de agua

Más producción de Petróleo con menos producción de Agua



Video

https://vimeo.com/petrotal/pozoshorizontales

PetroTal

vimeo Soluciones Funciones Recursos Ver Precio Comunicarse con Ventas Buscar videos, personas y más Iniciar sesión Unirse Nuevo vide

Perforación de pozos horizontales

hace 2 meses | Ver más

Más de PetroTal Perú

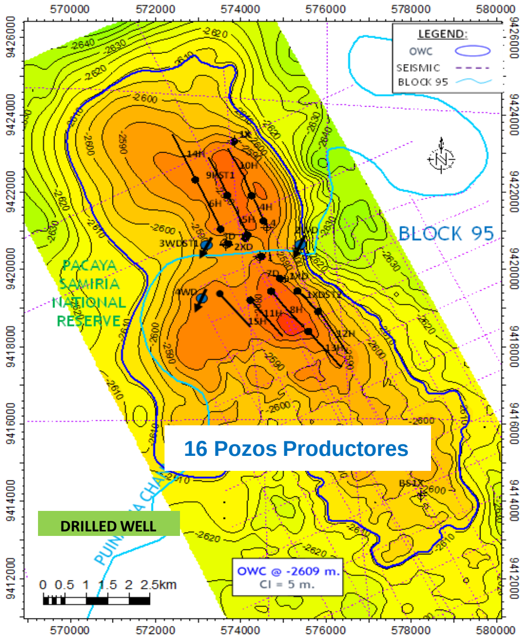
Reproducir de forma automática el siguiente video

Plan de desarrollo Bretaña Norte

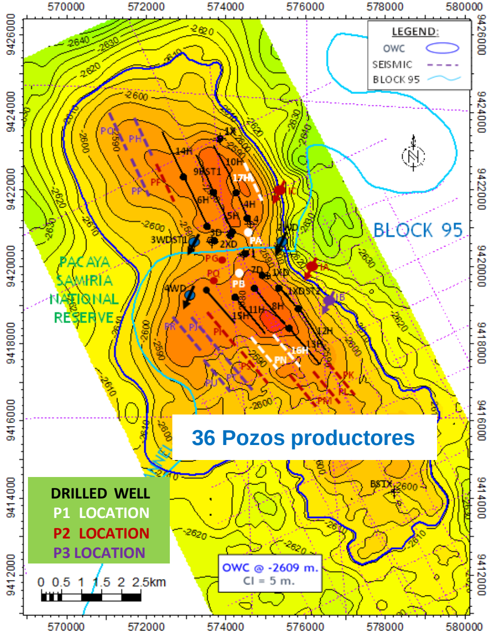
Características técnicas

- Estructura de cuatro vías bien definida limitada por una falla inversa al este.
- Tamaño del campo de 6.000 hectáreas
- Reservorio Vivian - Arenas fluviales masivas con excelente calidad de reservorio.
- Esta formación ha producido casi el 70% del petróleo en la Cuenca del Marañón en Perú
- El fuerte soporte acuífero y el control del agua utilizando la tecnología AICD aseguran el mantenimiento de la presión y altos volúmenes de recuperación de petróleo.
- Campos análogos en la cuenca tienen factores de recuperación de 22-42% vs Bretaña en 24% - posible upside en incrementar el factor de recobro en un 10-25%.
- Las reservas 3P y 2P tienen 36 y 29 pozos productores, respectivamente. Existe potencial para nuevas perforaciones infill y "probar" ubicaciones de perforación probables y posibles

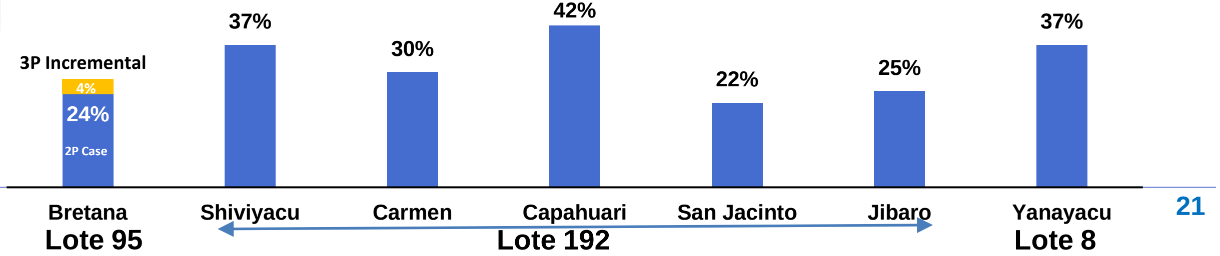
Ubicaciones perforadas actuales en el mapa



Desarrollo del campo completo en estructura

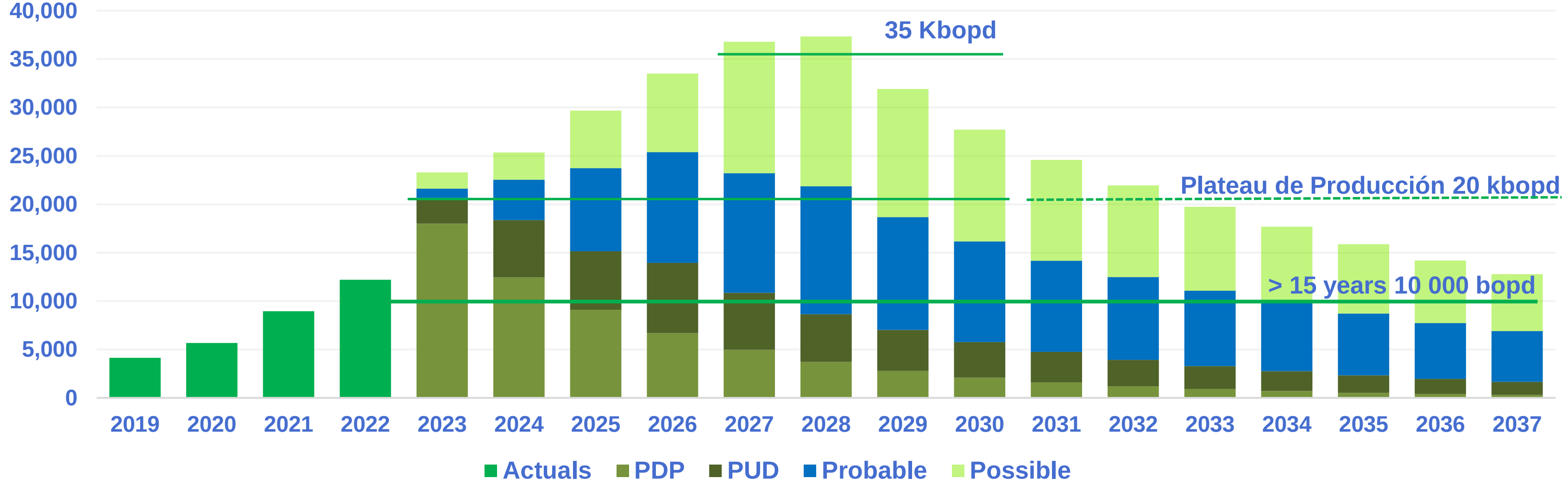


Factores análogos de recuperación



Bretaña Norte: Hacia los 35-40 mil bopd

Netherland Sewell (“NSAI”) perfil de producción (bopd)



- **~15 años de producción > 10 000 bopd** con las reservas 3P
- Pico de producción de **37 000 bopd** posible
- Posibilidad de aplanar la producción máxima en un **perfil de producción plurianual** de 20,000 a 25,000 bopd

Caso	Pozos	OOIP Mmbbl	Reservas Mmbbl	Factor de recobro
1P	21	329	46	17%
2P	29	445	97	24%
3P	36	632	168	28%

Futura expansión del Lote 95

Drilling Schedule	Capex per well	Q323	Q423	Q124	Q224	Q324	Q424	Q125	Q225	Q325	Q425	Q126	Q226	Q326	Q426	Q127	Q227	Q327	Q427	Q128	Q228	Q328	Q428	Q129	Q229	Q329	Q429	Q130	Q230	Q330	Q430	Q131	Q231	Q331	Q431
Iberia	$20/well													x	x	x		x		x		x		x		x						+ 2 additional wells			
Tapiche South	$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	
Dry hole capex $20 million/well	Seismic / Permits/ interpretation					US$ 30 millones								Primera producción																		+ 1 additional well			

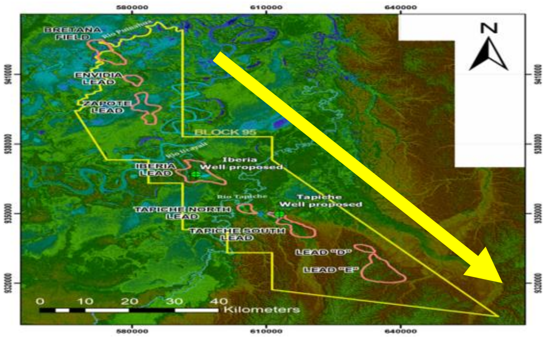
Capex estimado 2026 – 2035

Nuevos pozos = 49 x ~US$20 million = ~US$1000 million

Total facilities = ~$1,300 million
Total capital = ~$2,400 million

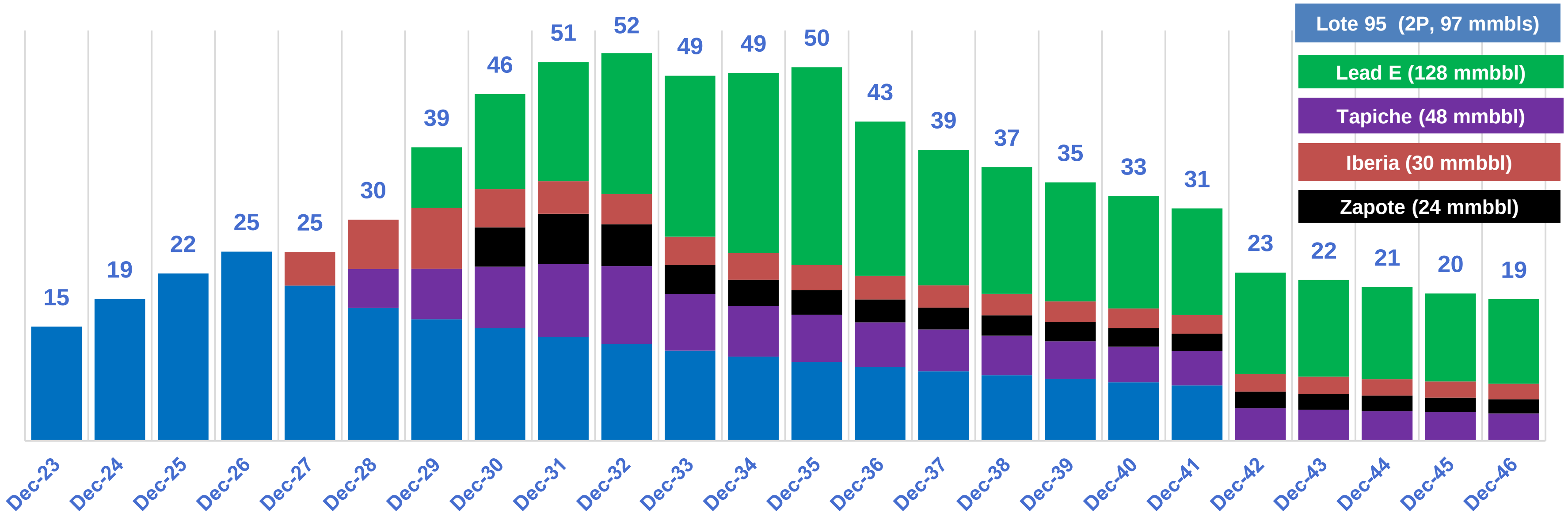
Gasto en instalaciones asociadas 2026 – 2035

- Dry hole/technical learning - US$160 million
- Seismic - US$30 million (2025 spend)
- Platforms - US$100 million
- Loading facilities/tanks - US$300 million
- Camps/clearing/construction (4 camps) - US$150 million
- Power Generation - US$250 million
- Water Disposal - US$200 million
- Abandonment/Environmental - US$100 million



Lote 95: Hacia los 50-60 mil bopd

Perfil de producción en kbopd



Recursos estimados 2C, Reporte Netherland Sewell (“NSAI”) a dic 2022.

¡PetroTal una compañía liderada y operada por peruanos, tratando de hacer grande al Perú!

Somos energía que genera bienestar

Gracias

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

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

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

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		