FEX

ENERGÍA QUE TRASCIENDE

ENERGÍA 2022

May 19, 2022

GEOLOGY & RESERVOIR

#FEXenergía

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Use of AICDs to increase the Recovery Factor in fields with a strong bottom aquifer: Bretana Field - Peru

Antonio Zegarra
Willy García

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REGIONAL LOCATION

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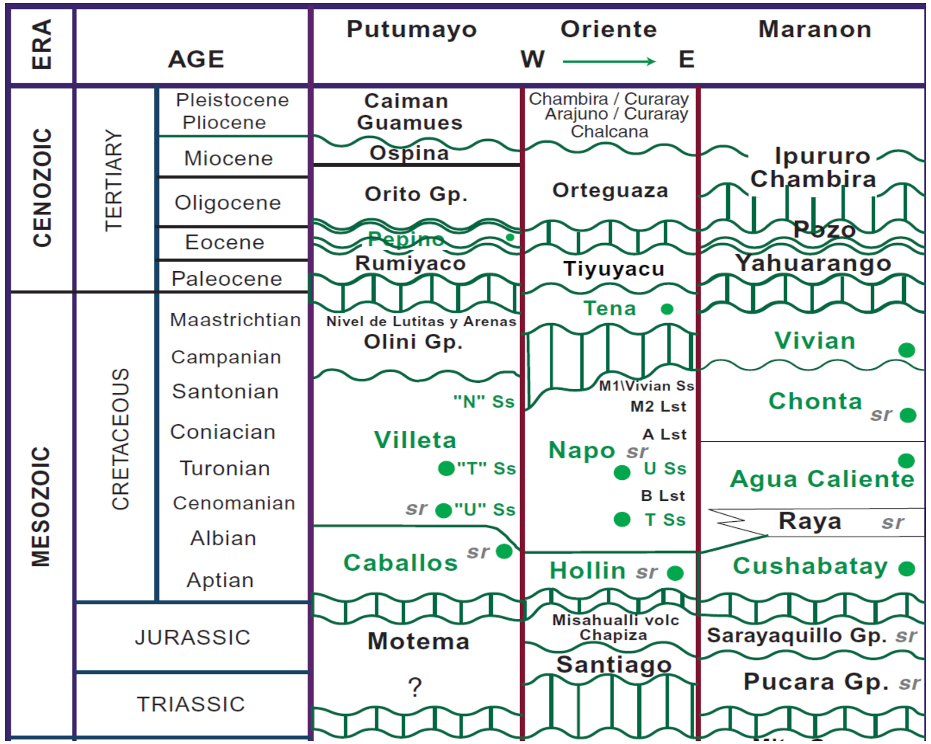

- The Marañon basin is the southern extension of a larger basin that covers the Putumayo (Colombia) and Oriente (Ecuador)
- Bretana Field is a subtle structure located on the south-eastern margin of the basin

LOCAL LOCATION

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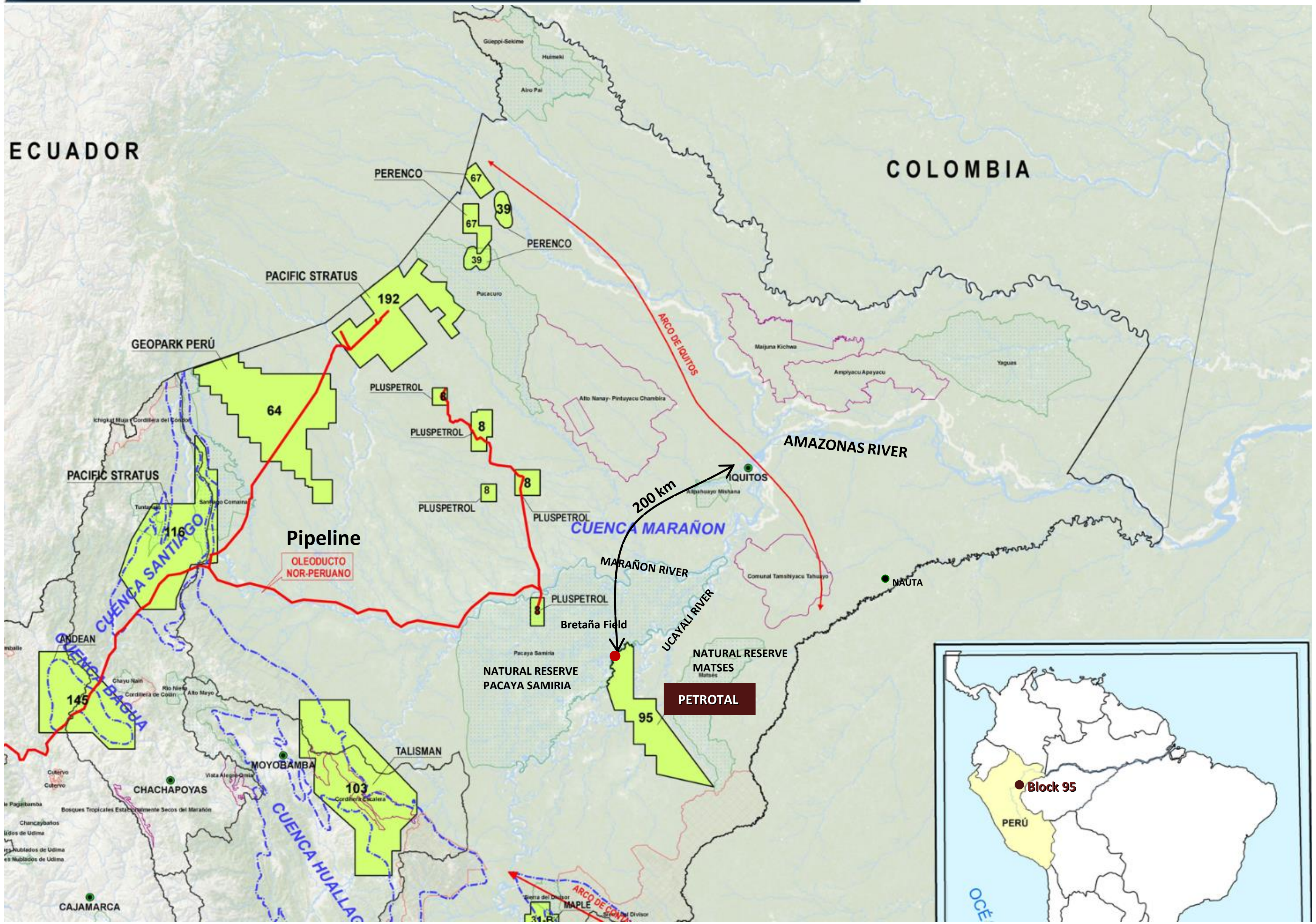

- The field it is located at the southern end of the basin
- Nearby fields to the Bretana asset have robust recovery factors with similar geologic characteristics

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STRUCTURE

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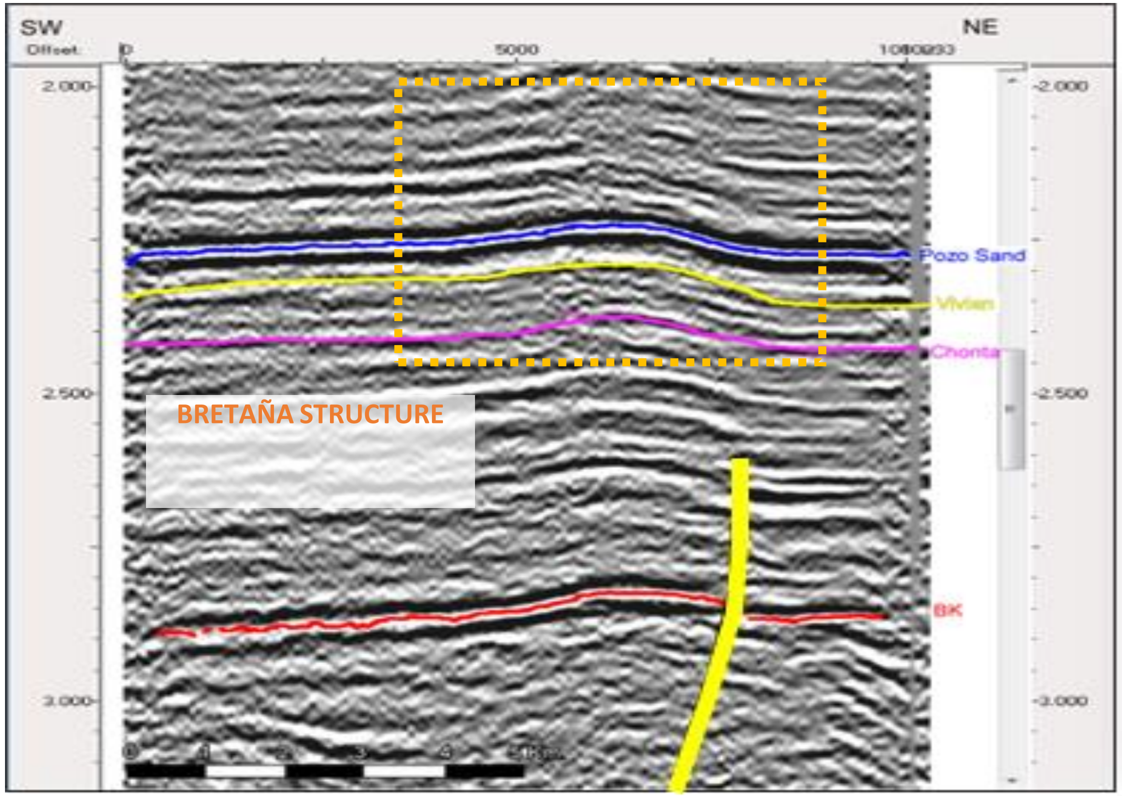

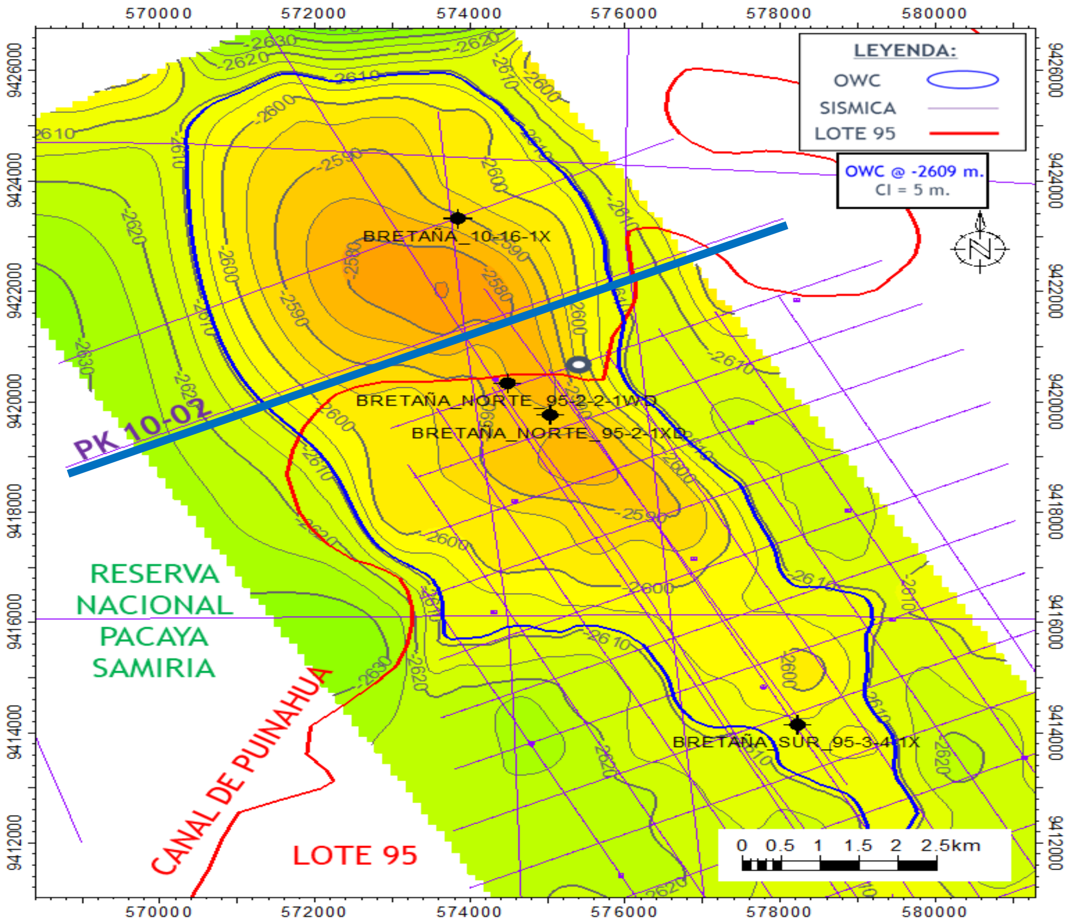

- The trap is induced by a reverse basement fault that does not reach the Vivian formation and defines a subtle low relief, closed on all 4 sides of an elongated structure in the NW-SE direction

ELECTRICAL PROFILE

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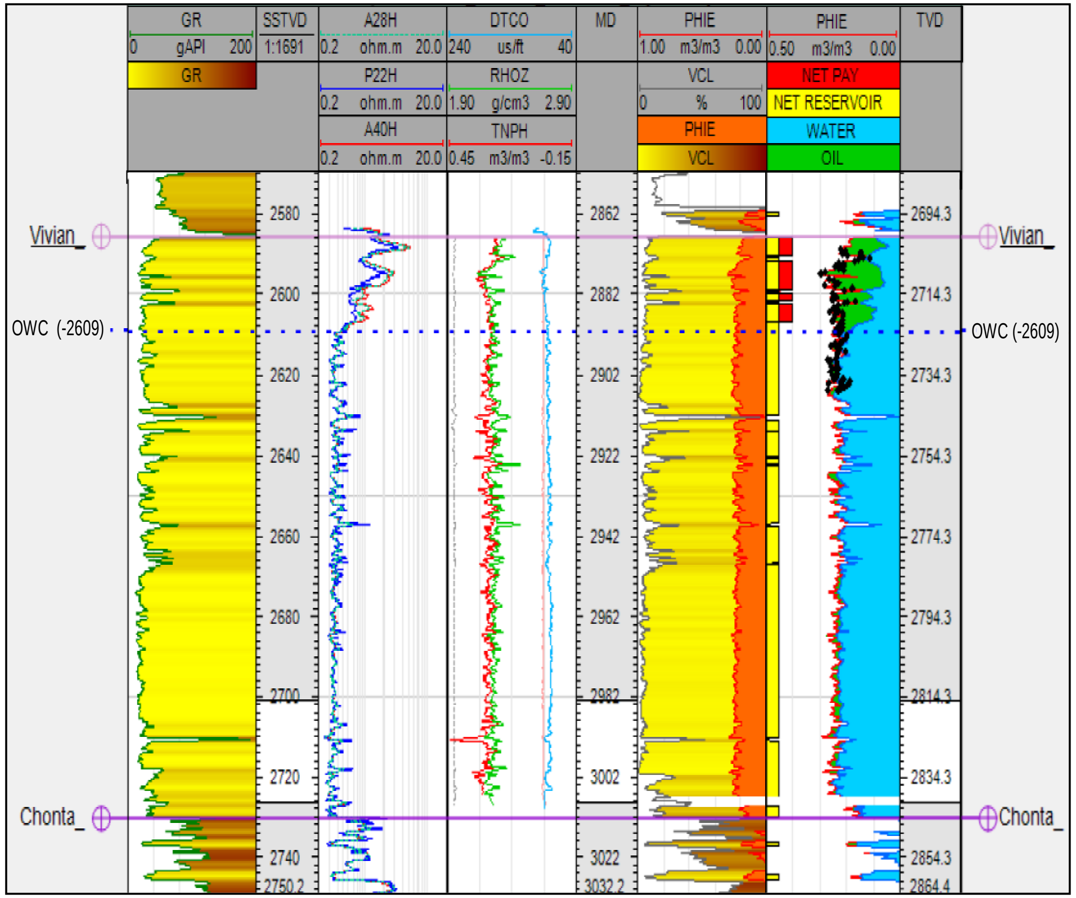

RESERVOIR ZONE:
- GROSS = 144 m
- NET RESERVOIR = 135 m
- Phie (avg) = 23 %
- Vclay (avg) = 7 %
- K core (avg) = 1000 mD.

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 %

- Fluvial deposits consisting mostly of complex channels in a braided river system, with little or no evidence of simple deposits
- The channels present a decreasing grain system towards the top

STRUCTURAL SECTION

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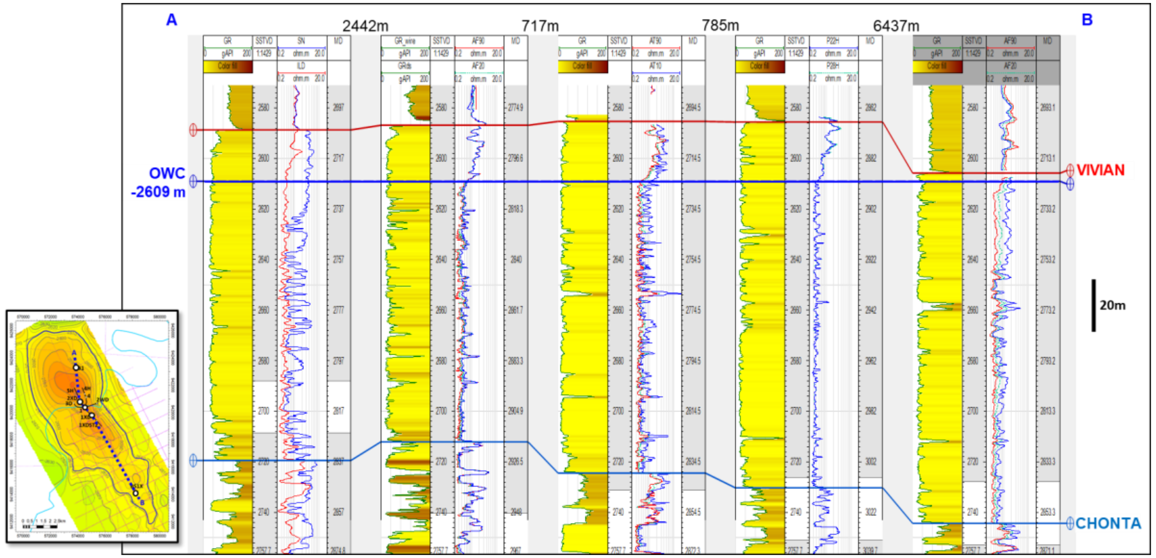

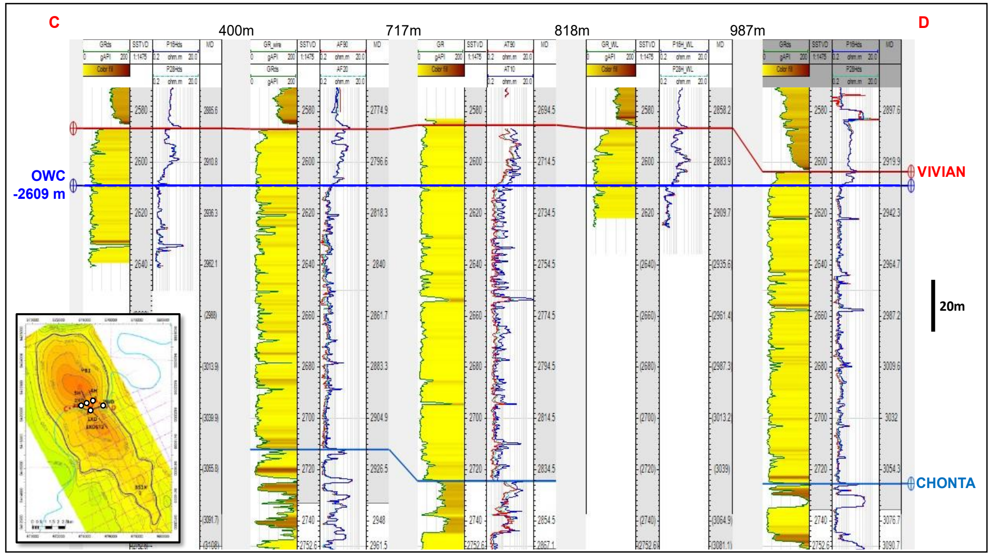

- North-South and East-West Sections of the Vivian Formation
- Peaks in GR are not correlatable, consequently barriers to vertical flow are local. A very strong bottom aquifer is confirmed
- High resistivity zones are found at different levels, indicating their belonging to different channels

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ROCK AND FLUID PROPERTIES

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Initial reservoir conditions:

Pressure @ WOC	3942	psi
Temperature	214	°F

Oil Properties

API°	18.6	°API
GOR	25	scf/stb
Pb	320	psia
Oil FVF	1.056	bbl/stb
µ o	23.6	cp
Density	0.895	g/cc

Rock properties

Permeability	k	2000	md
Porosity	phie	22.6	%
Water Saturation avg	Sw	38.0	%
Oil Net pay	Ho	32.0	ft

Water properties

Salinity NaCl	82,000 ppm
Specific gravity	1.06

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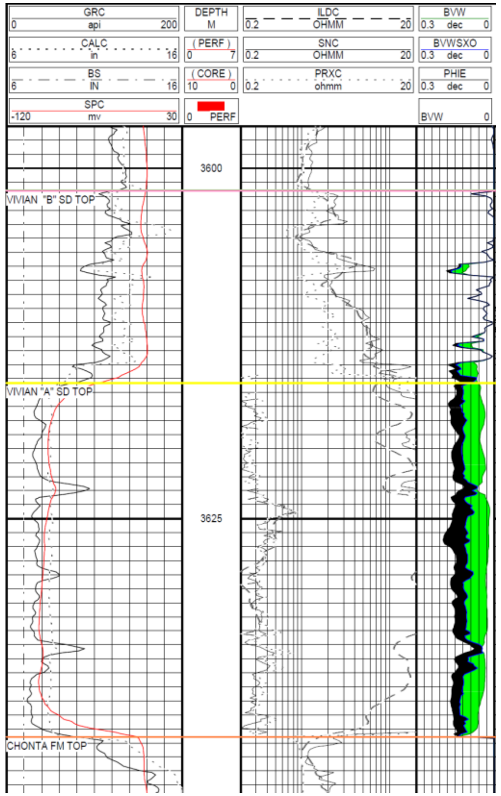
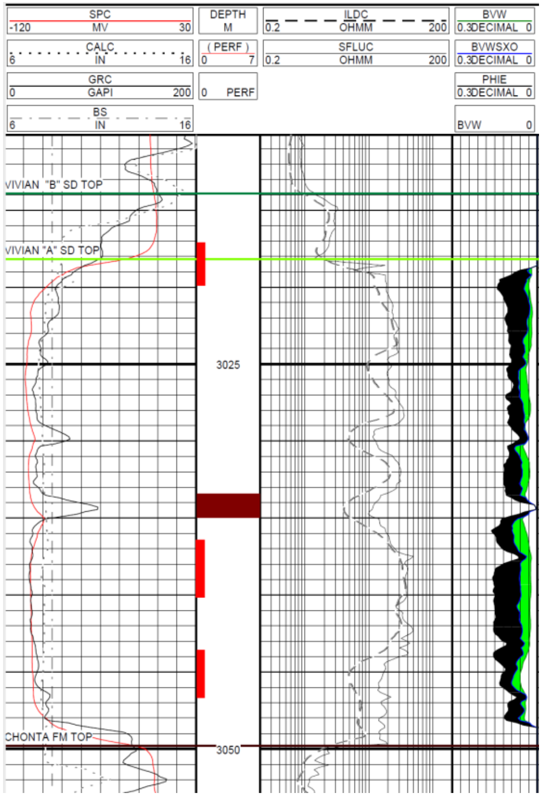
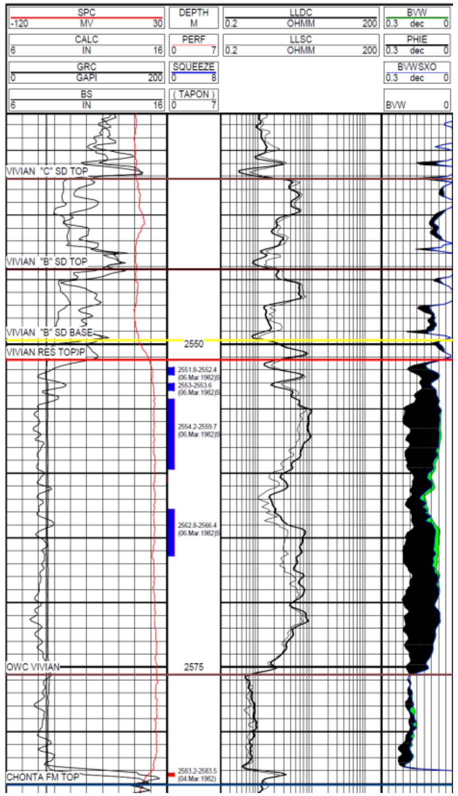


°API: 32° - 36°
RF: 40% - 45%



°API: 18° - 20°
RF: 30% - 35%



°API: 10° - 12°
RF: 10% - 15%

- Analogy with other fields in the Marañón basin; gravity °API and the recovery factor are considered under flank and bottom aquifers

FIRST HORIZONTAL WELL

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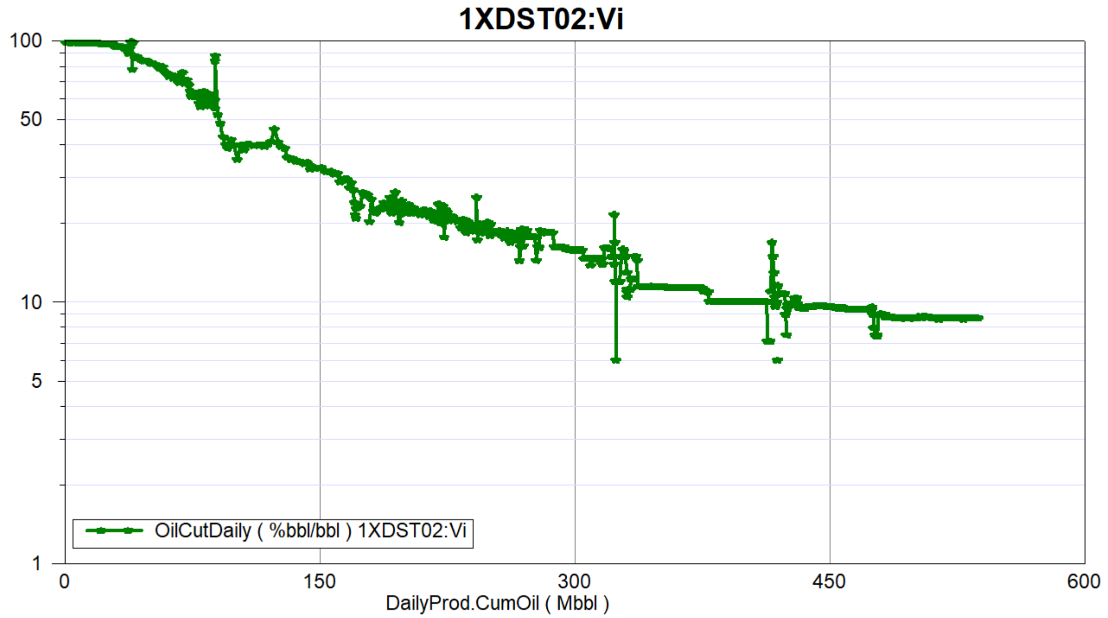
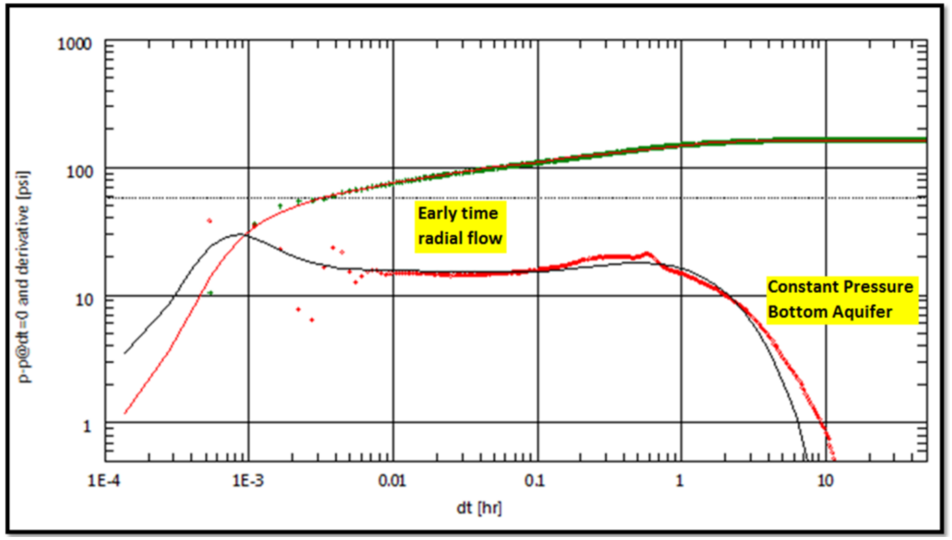
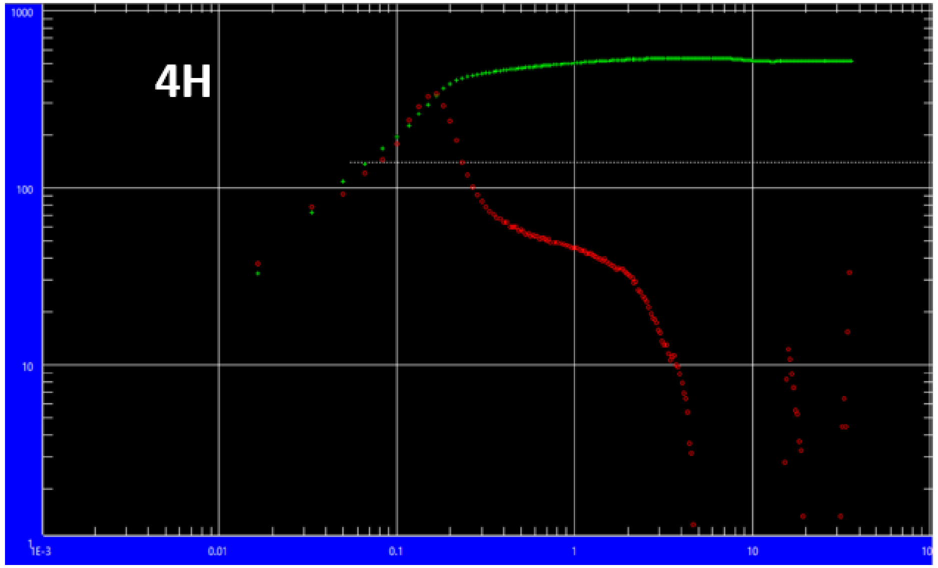
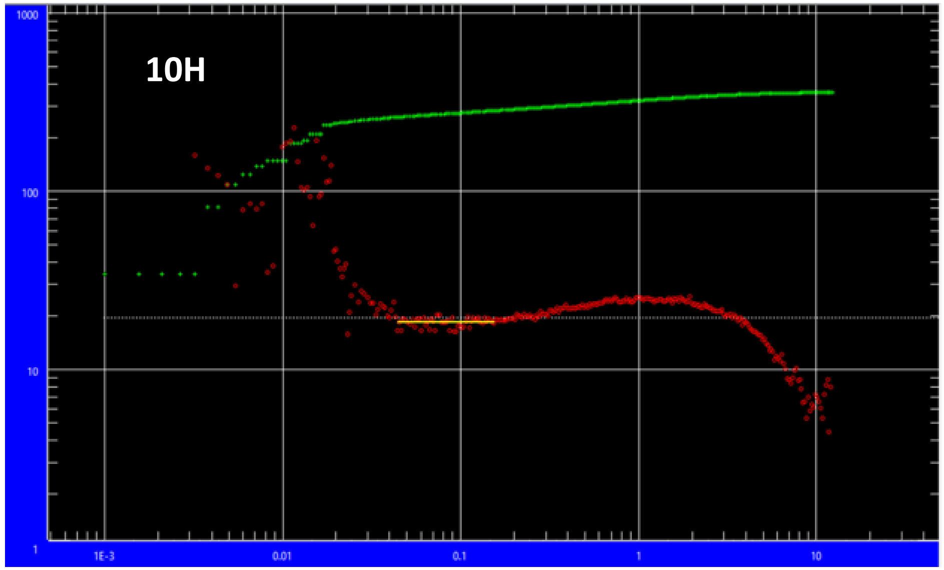
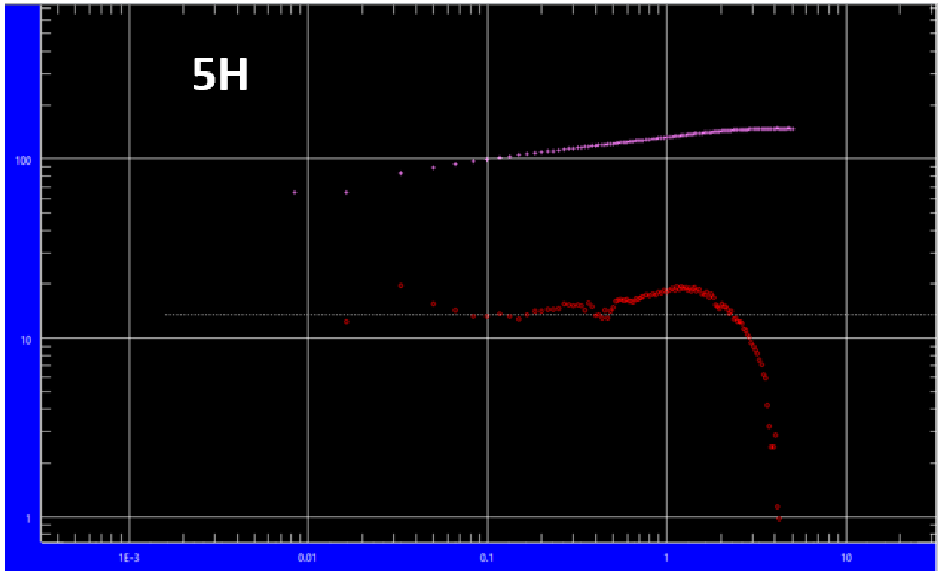




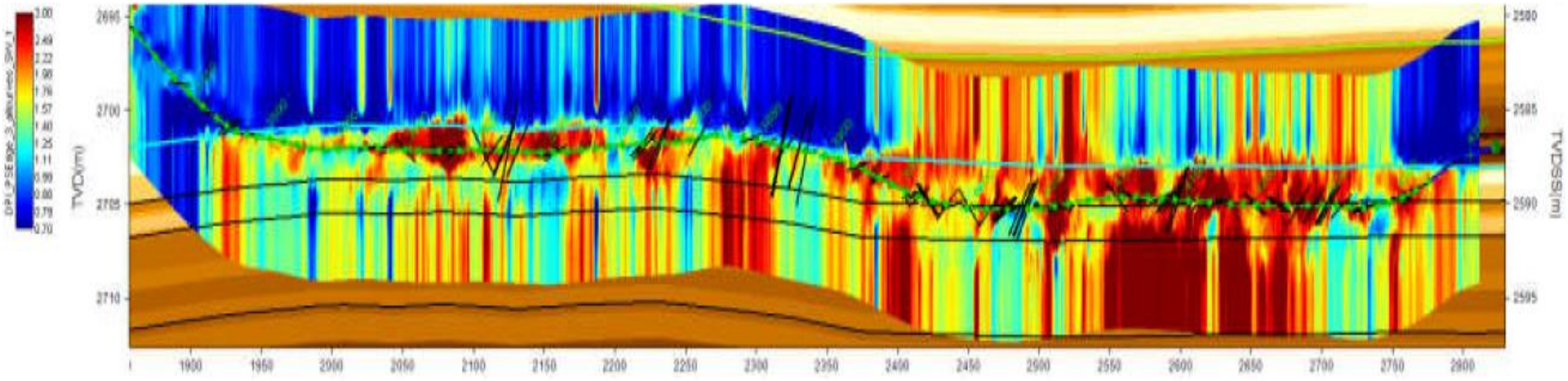
- Behavior of the first horizontal well drilled; It is complete with a hanger and a mesh to contain the production of sand
- Interpretation of the first training test; a short radial period is observed in the derivative curve, followed by a strong response of the bottom aquifer
- Cumulative oil production is less than 450 MBO at 90% water cut







- The footprint of the bottom aquifer is observed as a constant in the pressure derivative curve in subsequently drilled wells



- Geonavigation has had to be used to maintain the trajectory of the well within the different channels
- It has also served us to keep the trajectory as close to the top and avoid remnants of oil in the attic
- It has been possible to keep the well at a maximum distance from the water-oil contact

COMPLETION

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COMPLETION DESIGN

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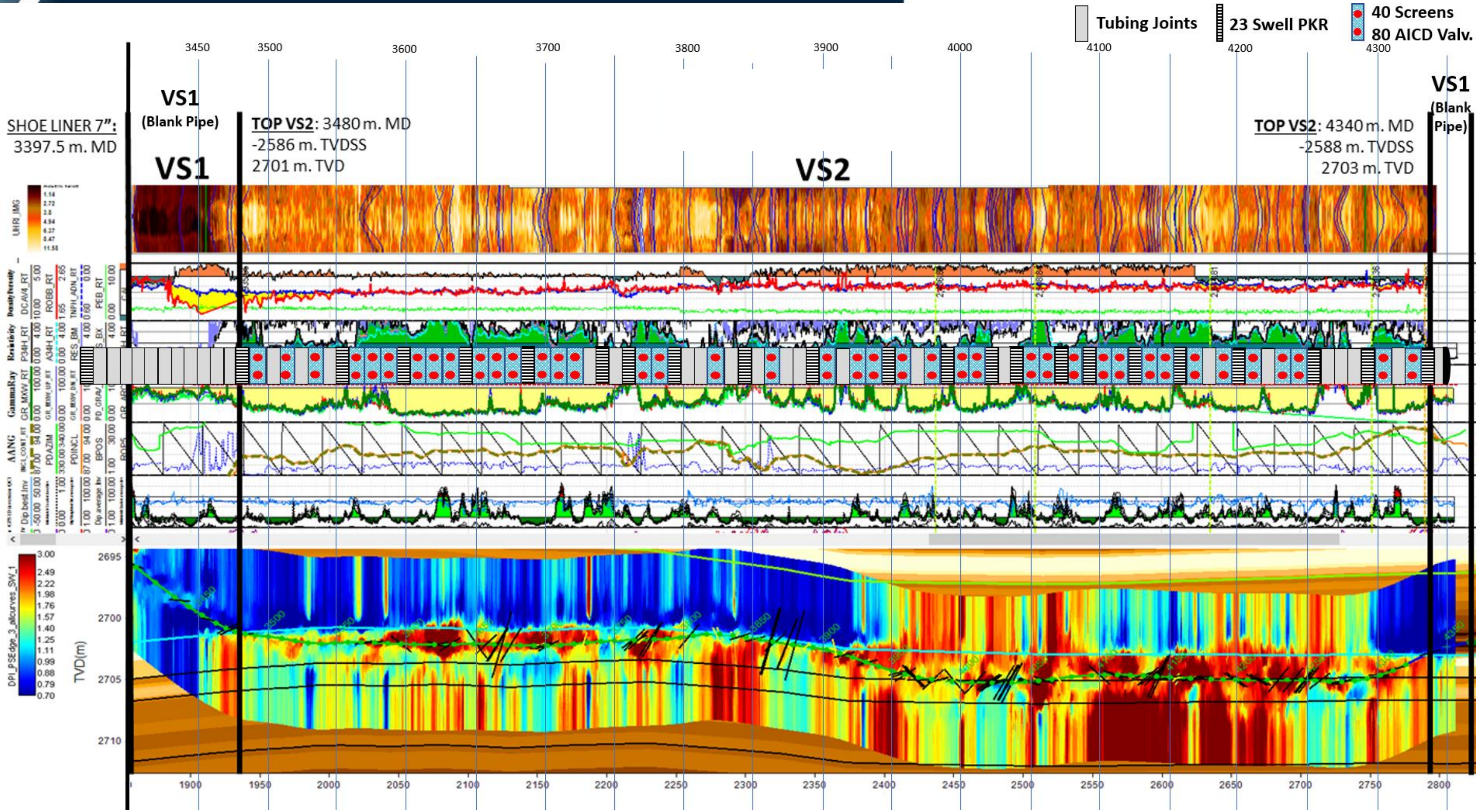
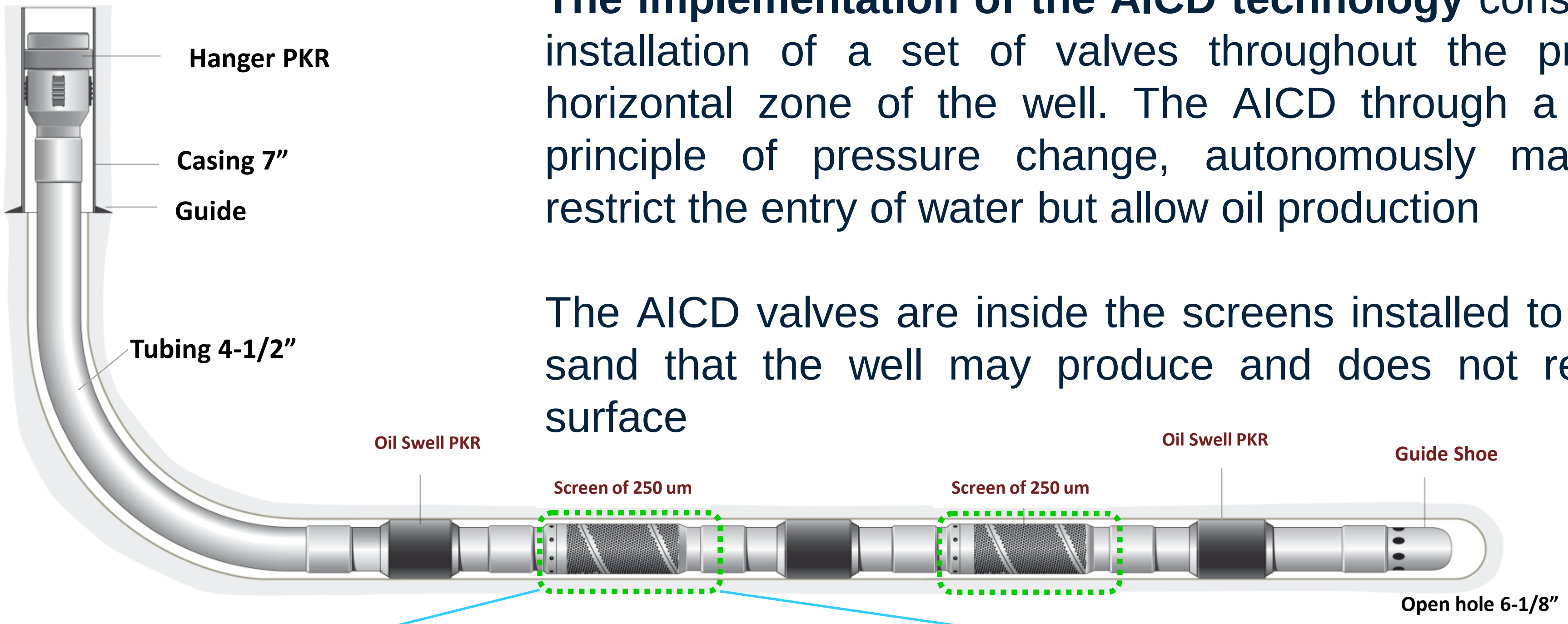


- Efforts are made to keep high resistivity zones separate from low resistivity zones (high saturation – high permeability)
- Isolate areas without any potential, due to the danger of producing sand

The implementation of the AICD technology consist in the installation of a set of valves throughout the productive horizontal zone of the well. The AICD through a physical principle of pressure change, autonomously manage to restrict the entry of water but allow oil production

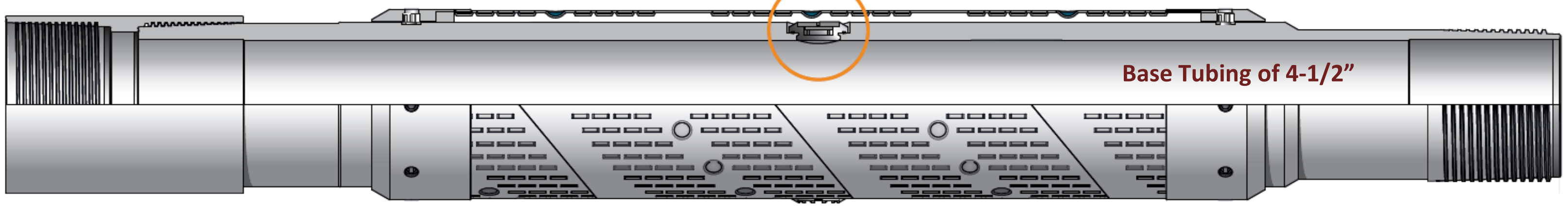
The AICD valves are inside the screens installed to filter the sand that the well may produce and does not reach the surface



Screens with AICD Valves

AICD

- ✓ Control the sand through 250 um filter.
- ✓ Restrict the entry of water through AICD valve



WELL SURVEILLANCE

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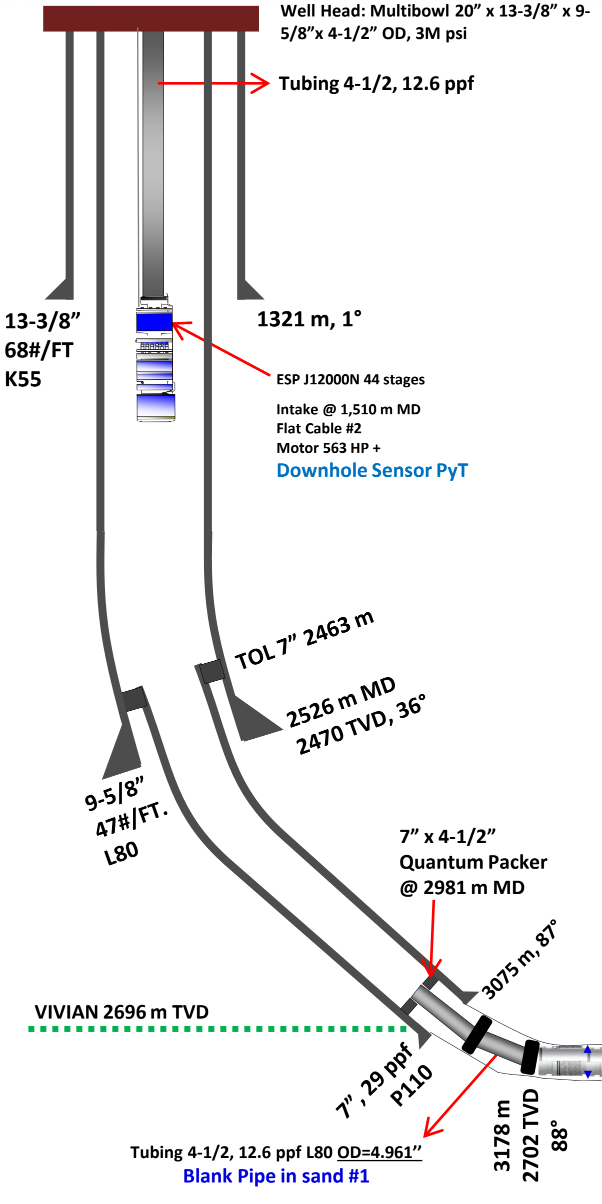
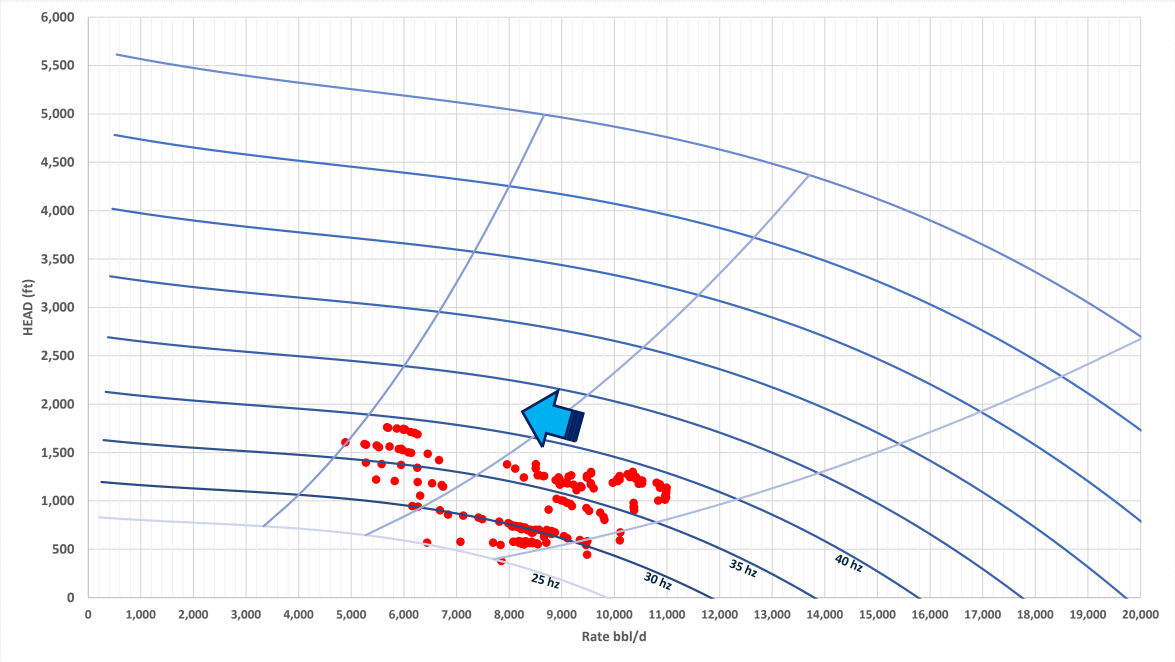
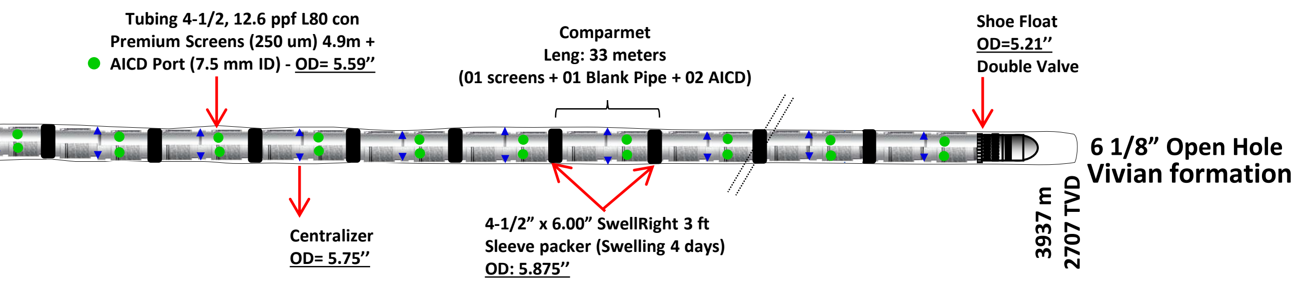


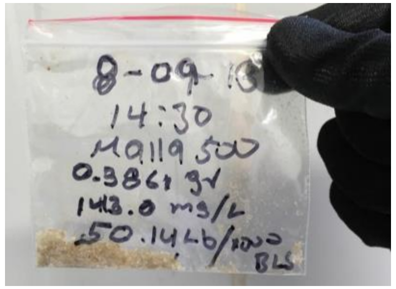
Maintaining a good well monitoring system is **essential**



Well Variable productivity index



Sand Monitoring Sensor Clampon



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RESULTS

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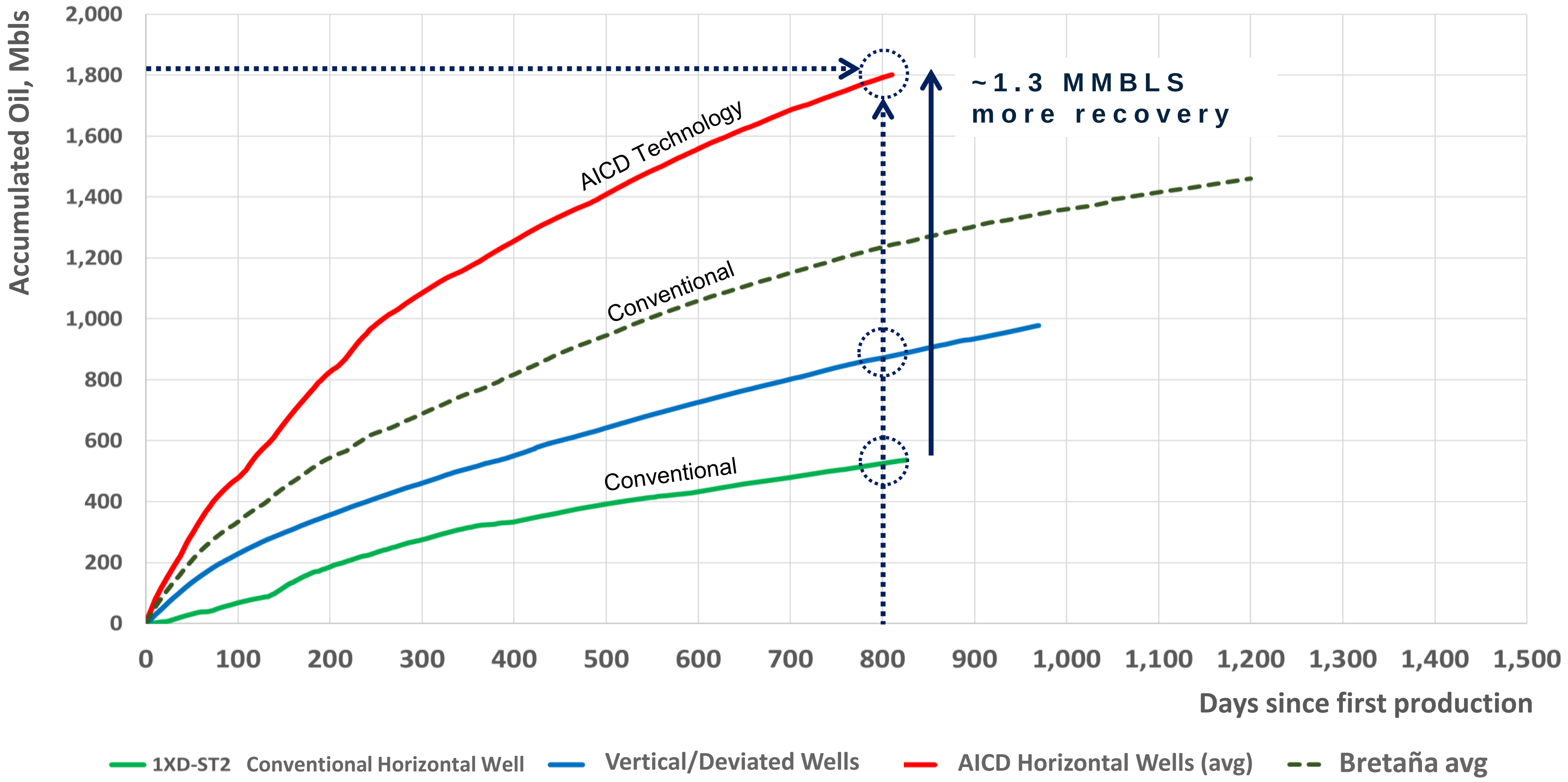
Significant increase in Oil production



RESULTS

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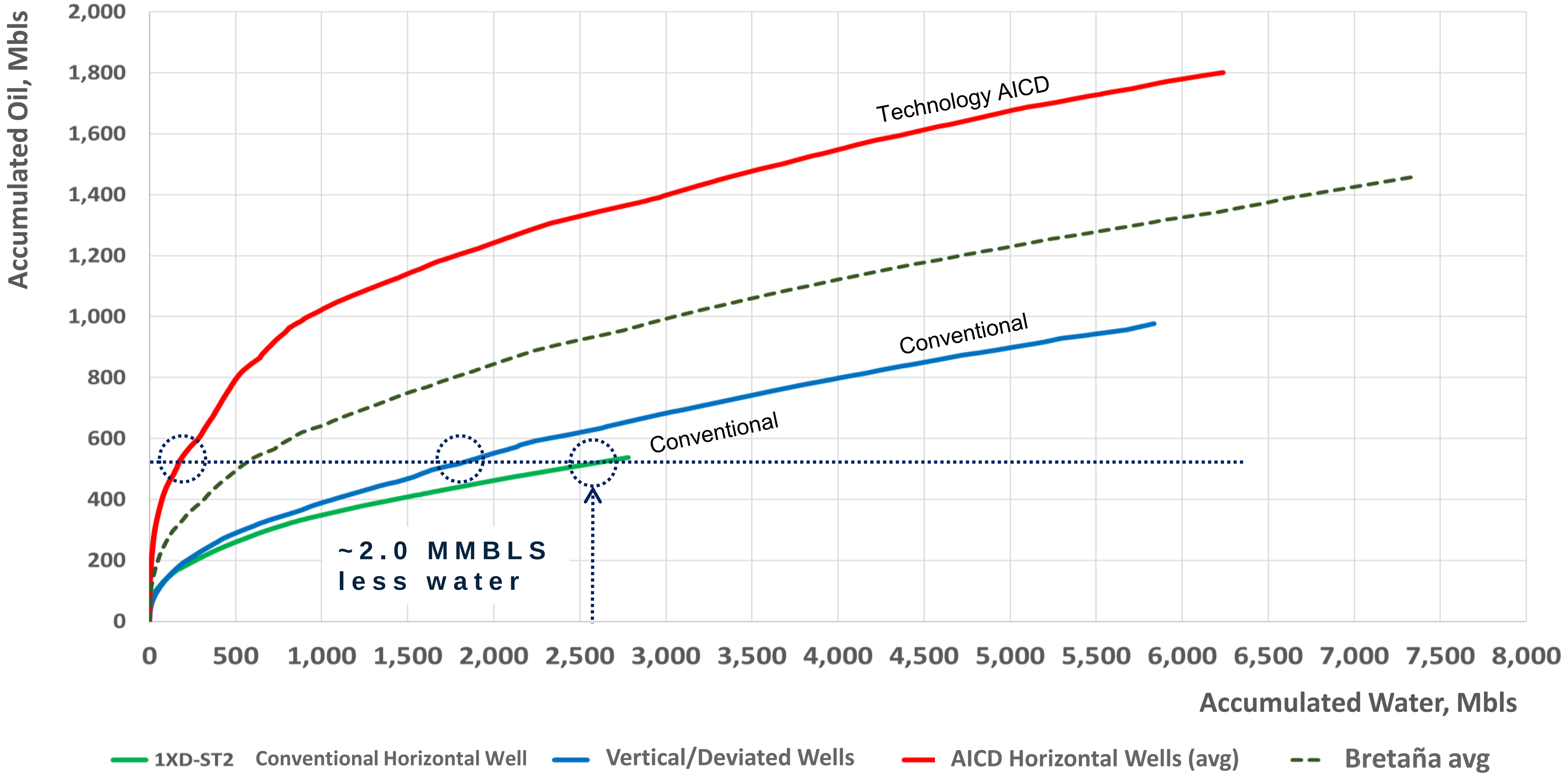
More Oil production with less Water production



CONCLUSIONS

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BENEFITS

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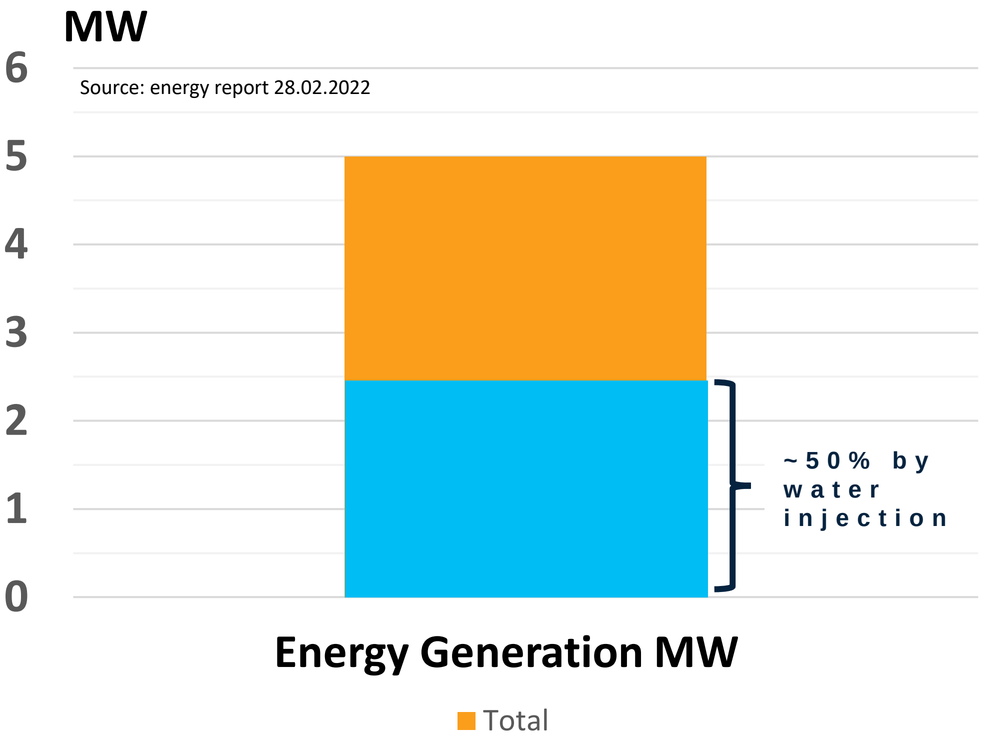
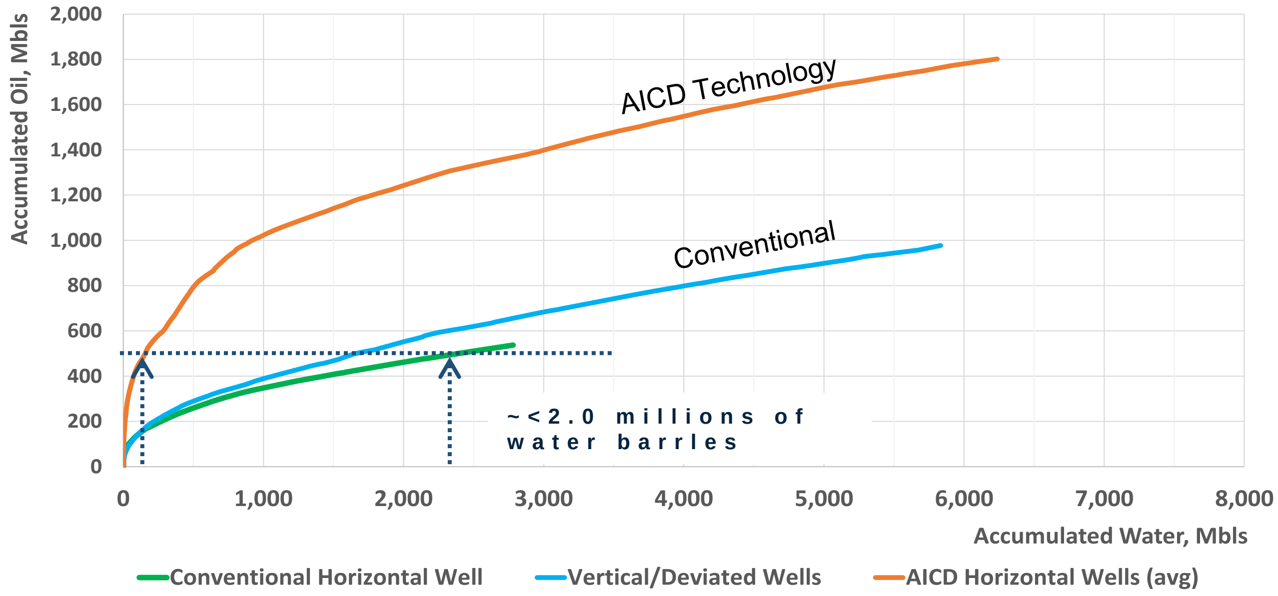
Significant reduction in water production of up to **2.0 MMbls**H_2O**/well** with the consequent reduction in energy use and tCO_2e emissions





~ Inyection of **1,000 bls** of water use **3.5 MWh** <> **2.2 Bls oil**
2.0 MMbls have consumed **7.0 GWh** <> **4,400 Bls oil/well**

BENEFITS

1. With the use of AICD's, a **much higher oil recovery is observed over time and with less water production**. The projection shows a tendency to increase the recovery factor

2. The **payout** of wells with AICD technology is **much faster**

3. **Less water is produced**, therefore significant **savings in the treatment of re-injected water are realized**

4. **The carbon footprint is reduced** by using less energy to produce and inject water

Target

Reduce **carbon footprint** in block 95 operations

Reduction of **40%** of greenhouse gases by the year **2030**

DRILLING

Manuel Casiano

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Drilling optimization and high DLS generation by using BHA with power drive archer in 8 ½” hole section for horizontal Wells, Field Bretaña – Block 95 – Perú

Manuel Casiano

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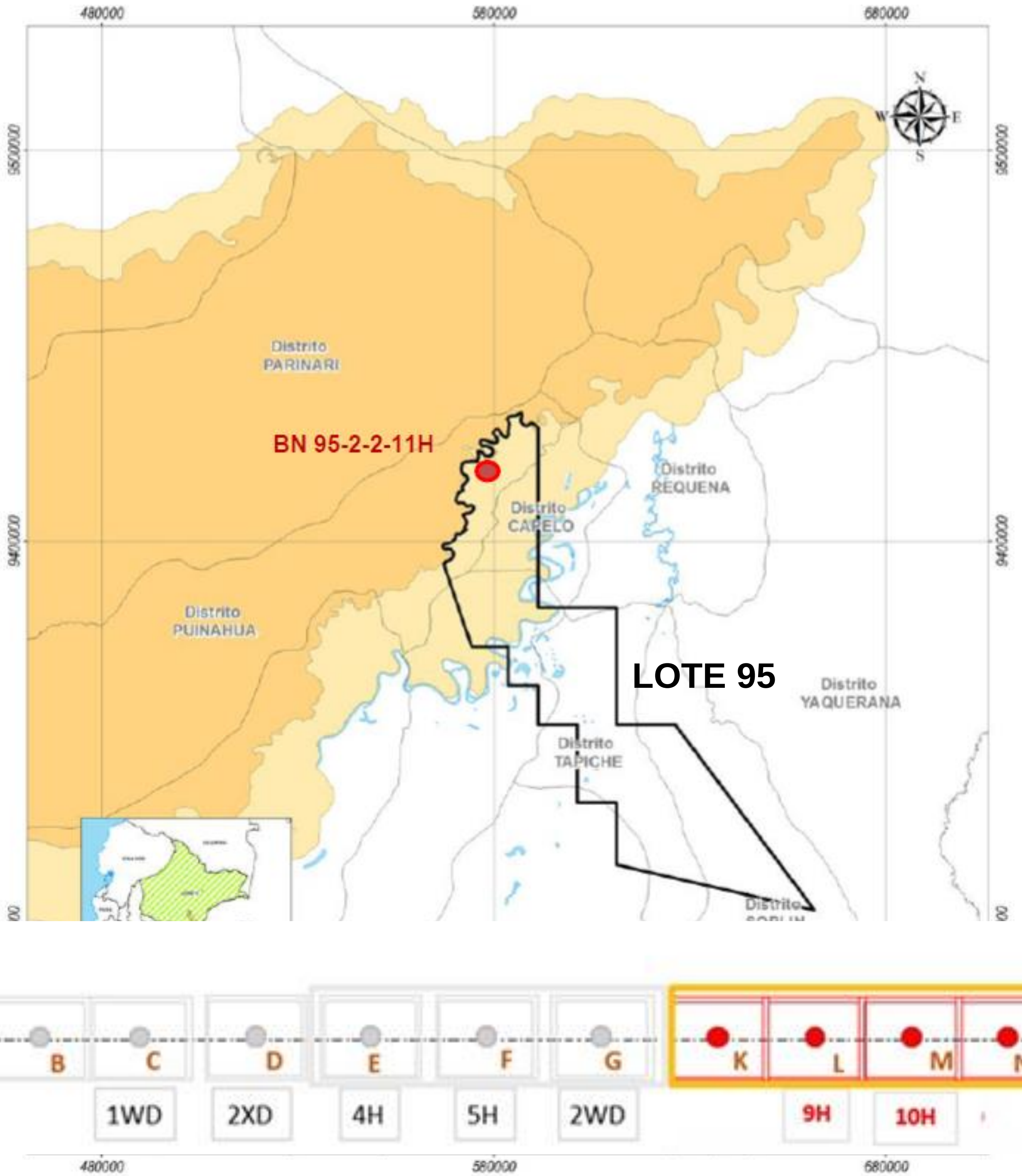
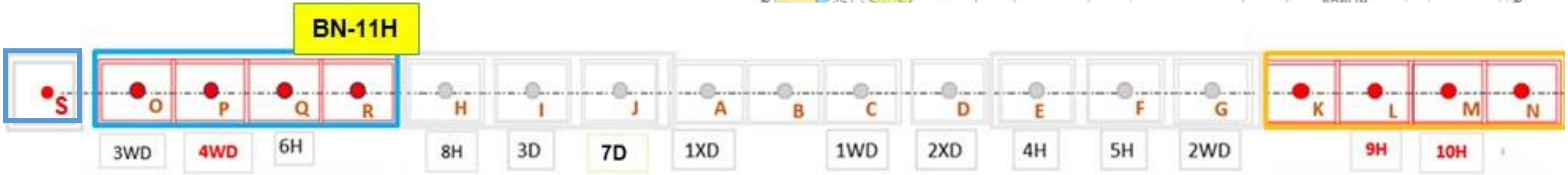
AGENDA

- Location – Block 95
- Structural map and offset well profiles
- Well design and initial BHA program
- Challenges
- Initial drilling days and normalized days - 8 ½” hole section
- PetroTal requirements
- Use of technology and performance
- Final drilling days and normalized days - 8 ½” hole section
- Drilling optimization – 8 ½” hole section
- Well Design and final BHA program
- Conclusions

LOCATION – BLOCK 95

- Block 95 – PetroTal (Dic 2017)
- Field Bretaña – Loreto - Perú
- Access: river & air (helicopter)
- 12 drilled wells (PetroTal)
- 60% horizontal wells & 40% directional wells
- Current Oil production: >16,000 BOPD
- Drilling development project (Oil well producers and water injection wells)





LOCATION – BLOCK 95

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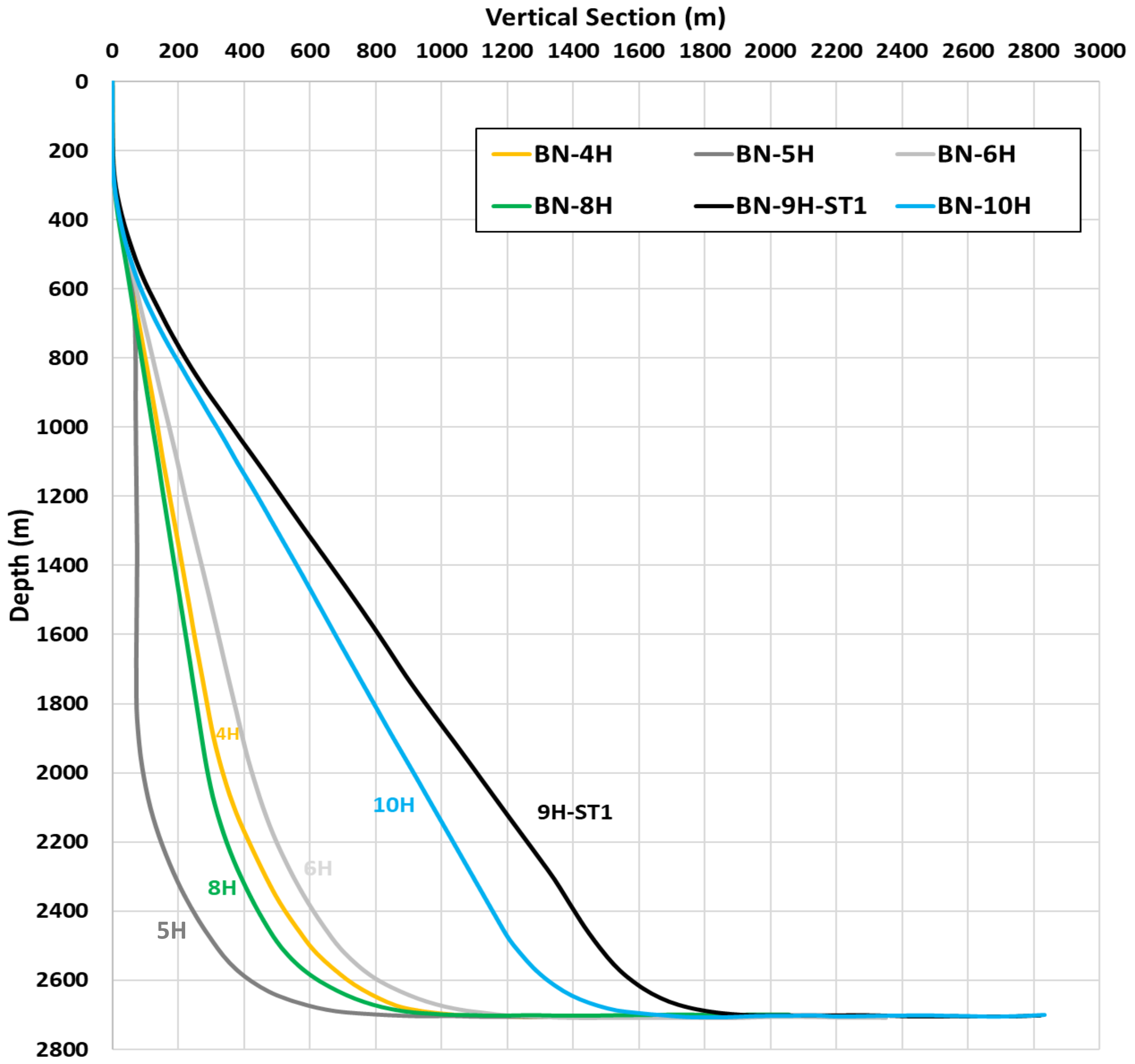
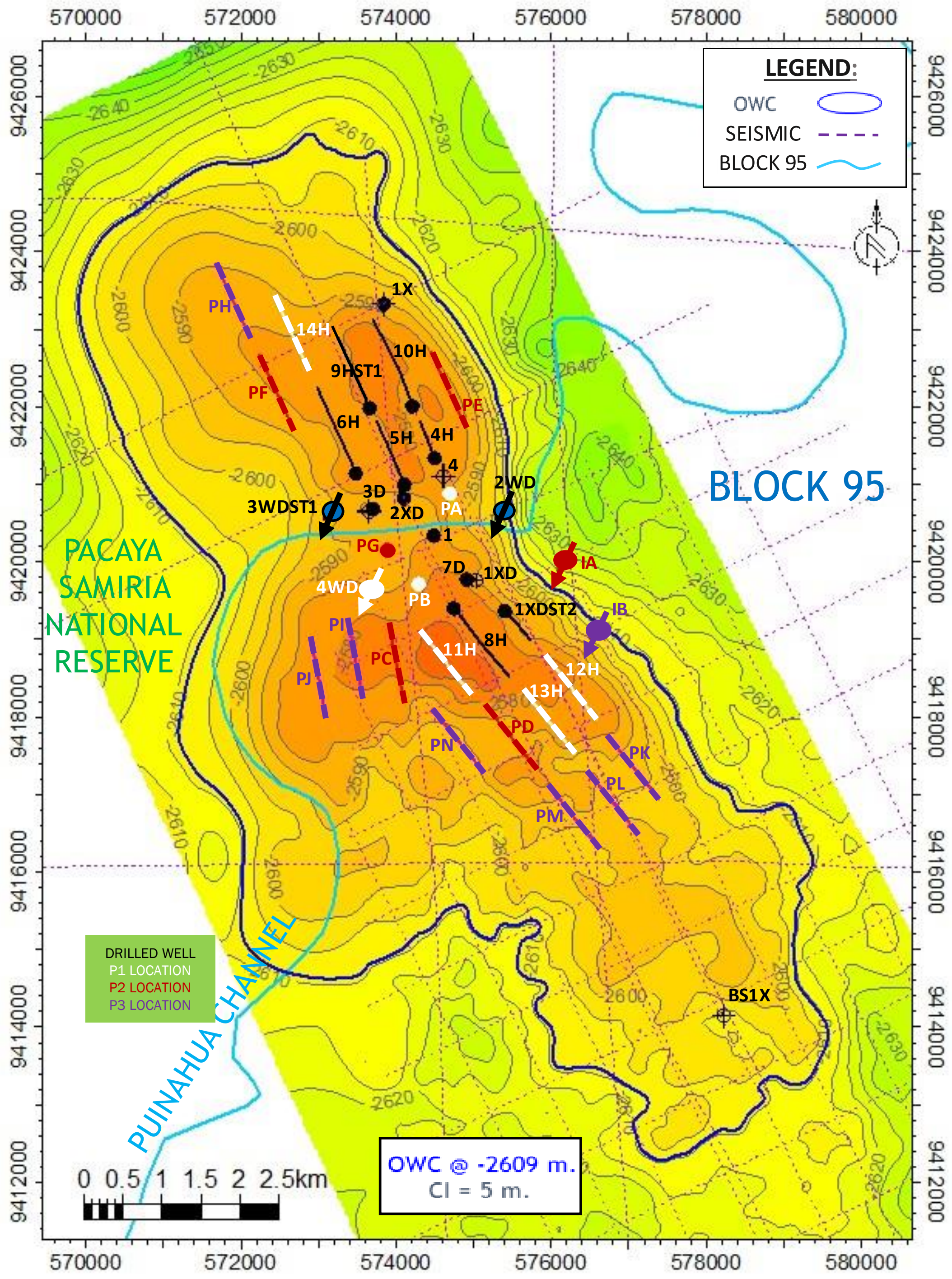
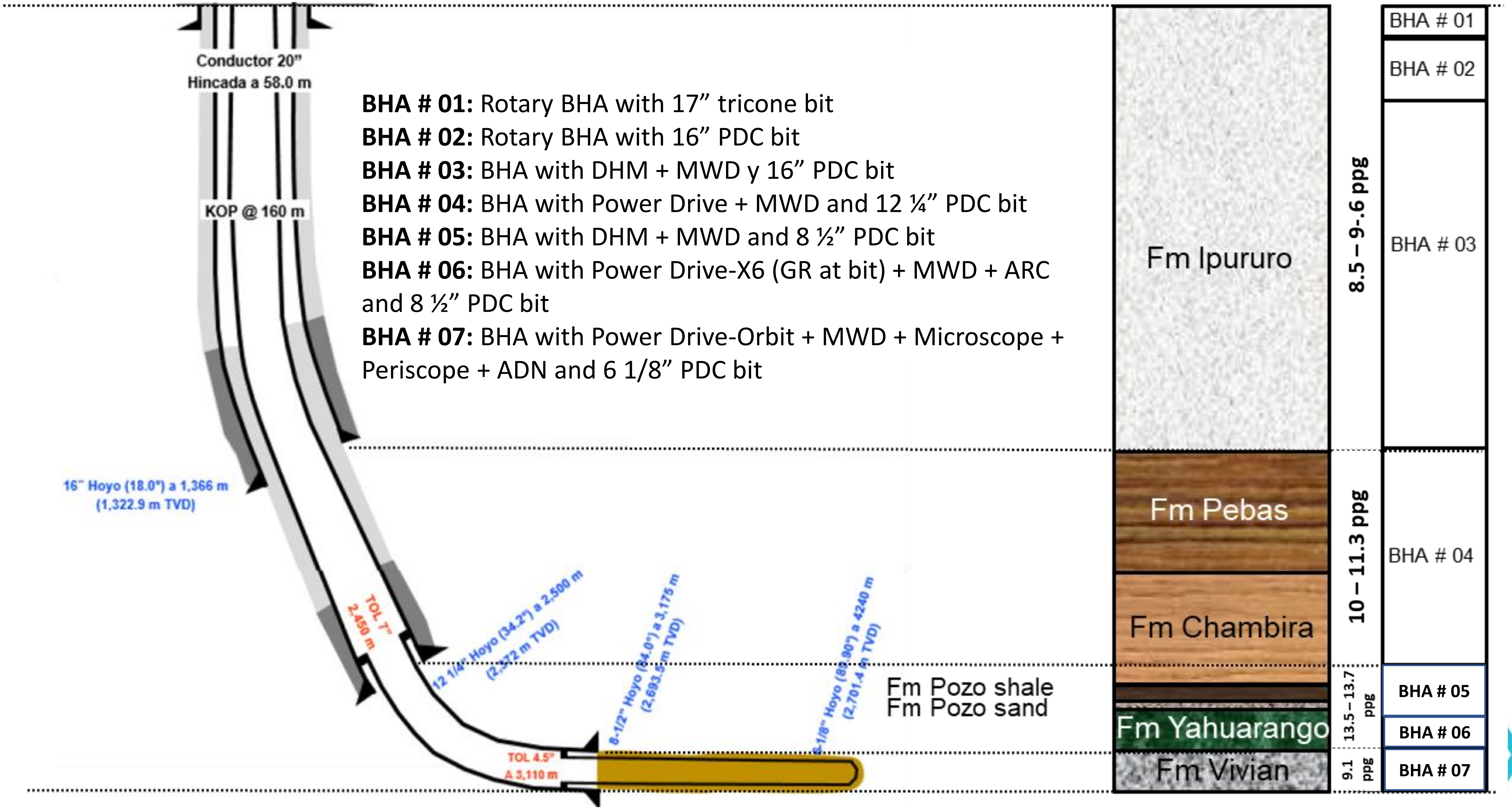
STRUCTURAL MAP & OFFSET WELL PROFILES





BHA # 01: Rotary BHA with 17” tricone bit
BHA # 02: Rotary BHA with 16” PDC bit
BHA # 03: BHA with DHM + MWD y 16” PDC bit
BHA # 04: BHA with Power Drive + MWD and 12 ¼” PDC bit
BHA # 05: BHA with DHM + MWD and 8 ½” PDC bit
BHA # 06: BHA with Power Drive-X6 (GR at bit) + MWD + ARC and 8 ½” PDC bit
BHA # 07: BHA with Power Drive-Orbit + MWD + Microscope + Periscope + ADN and 6 1/8” PDC bit



TYPICAL WELL DESIGN – 8 ½” HOLE SECTION

Comments	MD (m)	Incl (°)	Azim True (°)	TVD (m)	TVDSS (m)	VSEC (m)	DLS (°/30m)	BR (°/30m)	TR (°/30m)
Casing 9 5/8"	2569.00	36.00	156.50	2479.45	2364.51	535.21	1.33	1.26	-1.24
Pozo Shale	*2579.59*	*37.35*	*155.52*	*2487.94*	*2373.00*	*541.51*	*4.17*	*3.83*	*-2.78*
Pozo Sand	*2719.57*	*55.71*	*146.44*	*2583.94*	*2469.00*	*642.46*	*4.17*	*3.93*	*-1.95*
Cambio de BHA	2751.00	59.90	144.99	2600.68	2485.74	668.96	4.17	4.00	-1.38
Yahuarango	*2751.51*	*59.94*	*144.98*	*2600.94*	*2486.00*	*669.40*	*2.42*	*2.39*	*-0.46*
Tangente	3056.65	84.30	141.05	2693.95	2579.01	955.09	2.42	2.39	-0.39
Vivian	*3076.68*	*84.30*	*141.05*	*2695.94*	*2581.00*	*974.76*	*0.00*	*0.00*	*0.00*
Liner 7"	*3090.00*	*84.30*	*141.05*	*2697.26*	*2582.32*	*987.84*	*0.00*	*0.00*	*0.00*

BHA with DHM (BH: 1.5°)
AVG ROP: 18 m/hr

BHA with Power drive X6
AVG ROP: 20 m/hr

8 ½” HOLE SECTION . DRILLING TIMES

- Use of 2 types of BHA´s (Surface trip)
- Re logging times (correlate landing point)

RISKS

- Involuntary Sidetrack.
- Exposure time for claystones

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INITIAL DRILLING DAYS – 8 ½” HOLE SECTION

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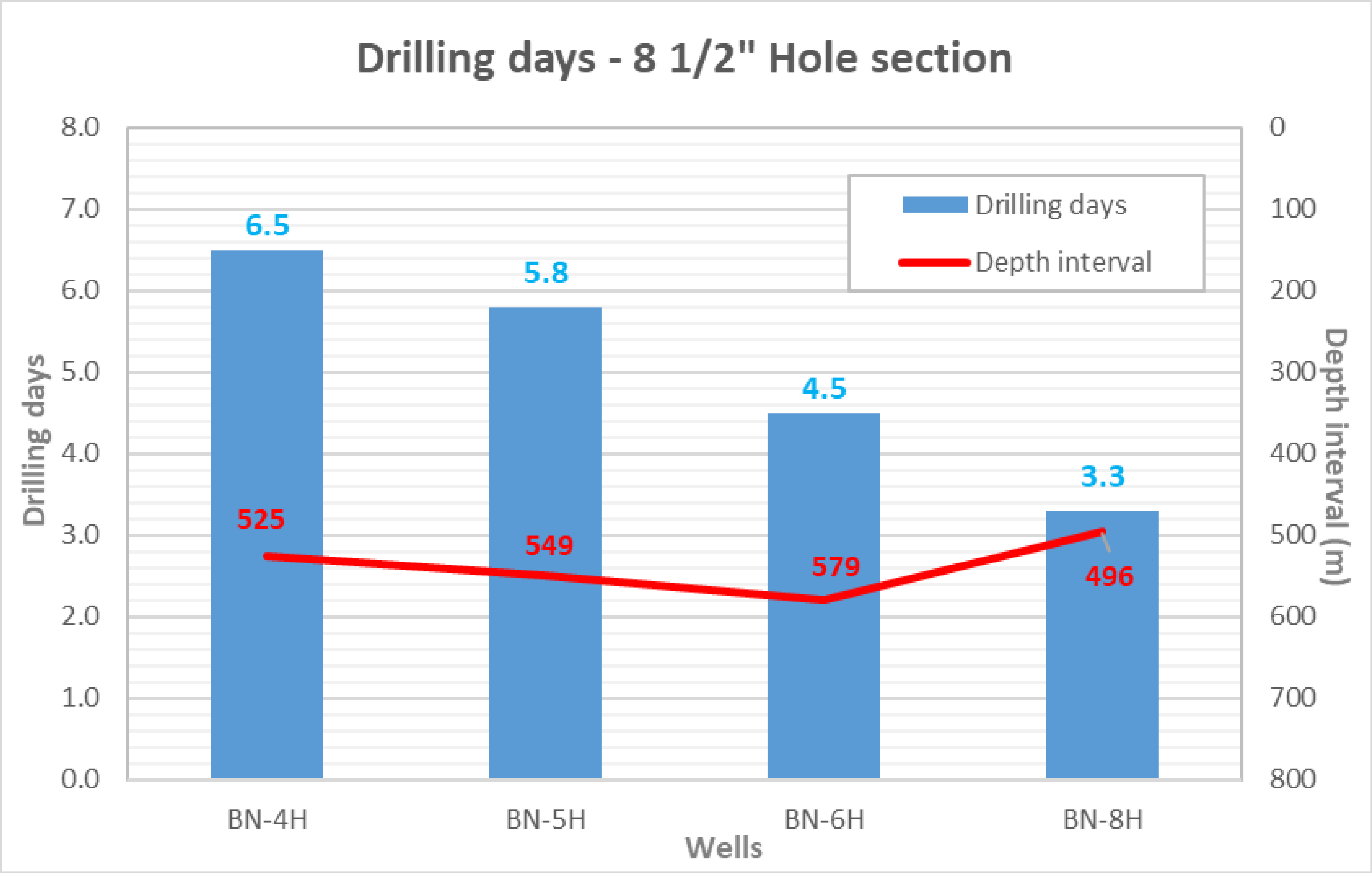

WELLS	% USAGE	
	DHM	POWER DRIVE
BN-4H	78.1	21.9
BN-5H	52.5	47.5
BN-6H	35.2	64.8
BN-8H	36.3	63.7

NORMALIZED DAYS – 8 ½" HOLE SECTION

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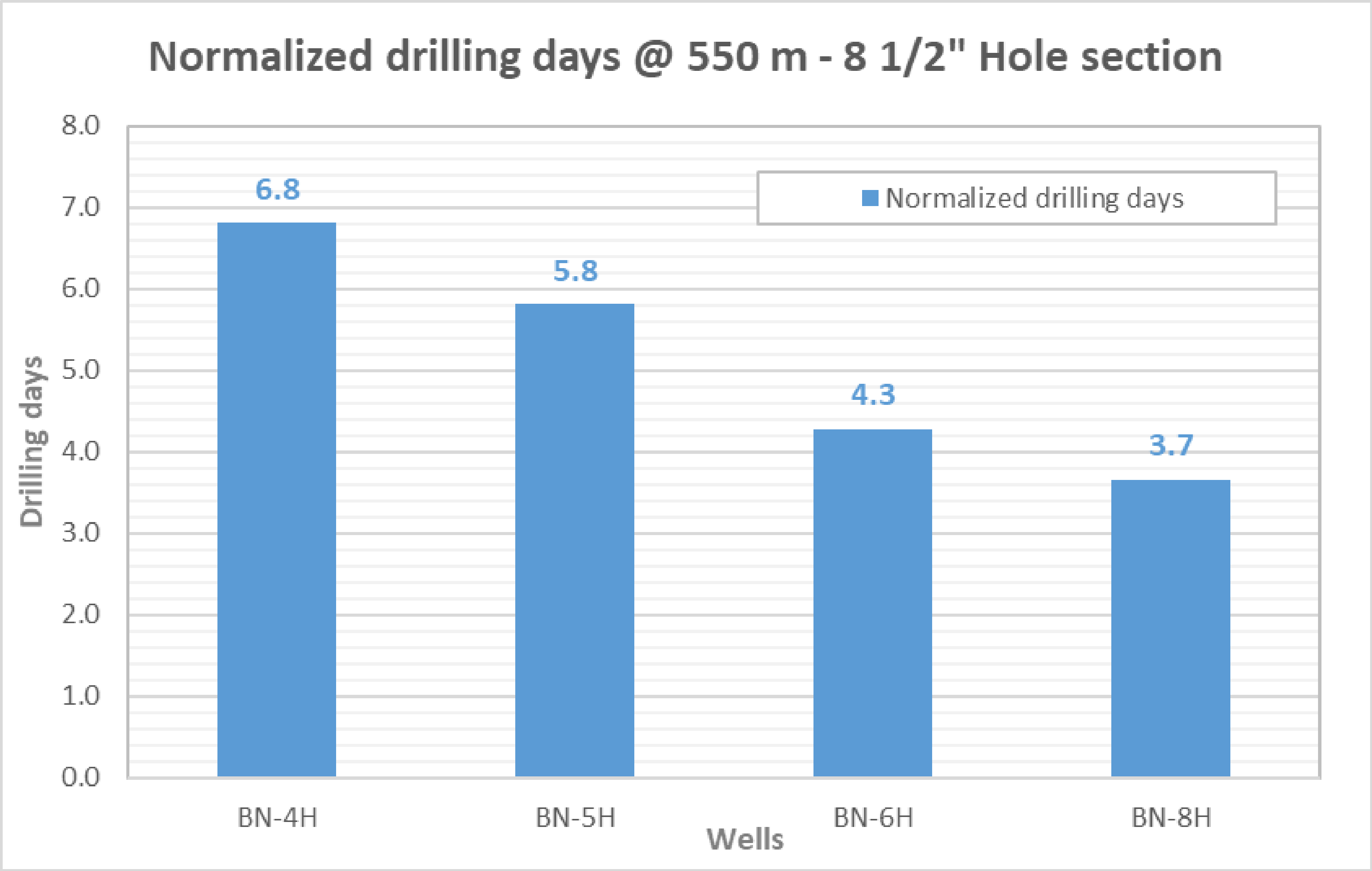

PETROTAL REQUIREMENTS

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REQUIREMENTS

- Drilling 8 ½” hole section (build and land the well) with only one BHA and capacity to generate DLS higher than 5°/30m

- Increase depth interval for 8 ½” hole section for future wells with complex trajectory profiles

TECHNOLGY SUGGESTED

- Power drive archer – point the bit (GR at bit)
- Drilling experiences from other wells to generate DLS up to 15°/ 30m

PowerDrive Archer 675

HIGH BUILD RATE ROTARY STEERABLE SYSTEM

Physical

Collar Diameter:	6.75 in
Max. Tensile Load:	400.000 lbf

Maximum tool curvature

Rotating:	15 °/100ft
Sliding:	16 °/100ft

Flow and Pressure

Flow Rate:	*See Hydraulic
Max. Operating Pressure:	20.000 psi
Actuador Pressure:	

Risk	Pressure
Hight	>750psi
Warning	700psi to 7
Good	600psi to 7
Warning	550psi to 6
Hight	<550psi

Mud Properties

Max. Dissolved Oxygen Content:	1 ppm
Max. LCM Size:	50 ppb MNP
Max. % Total Solid Sand Size Content:	1%
Mud Weight:	*See Hydraulic
pH Range:	9.5 to 12

Operating Specifications

Max. Cumulative duration S&S>100%:	30 minutes
Max. Cumulative Shock Count:	200.000>50 G
Max. Cumulative Shock Duration:	30 minutes
Max. Operating Temperature:	302°F / 150°C

WELL PLAN (BN-10H)

Comments	MD (m)	Incl (°)	Azim True (°)	TVD (m)	TVDSS (m)	VSEC (m)	DLS (°/30m)	BR (°/30m)	TR (°/30m)
9 5/8" Casing	*2600.00*	*32.35*	*353.14*	*2283.21*	*2168.27*	*1134.27*	*0.00*	*0.00*	*0.00*
KOP	2810.00	32.35	353.14	2460.61	2345.67	1245.39	0.00	0.00	0.00
Pozo Shale	*2841.81*	*35.90*	*350.70*	*2486.94*	*2372.00*	*1263.08*	*3.58*	*3.35*	*-2.30*
Pozo Sand	*2972.79*	*50.84*	*343.84*	*2581.94*	*2467.00*	*1352.60*	*3.58*	*3.42*	*-1.57*
Yahuarango	*2992.27*	*53.09*	*343.09*	*2593.94*	*2479.00*	*1367.94*	*3.58*	*3.47*	*-1.16*
Tangente	3260.00	84.30	335.39	2690.14	2575.20	1612.83	3.58	3.50	-0.86
Vivian	*3288.22*	*84.30*	*335.39*	*2692.94*	*2578.00*	*1640.55*	*0.00*	*0.00*	*0.00*
7" Liner	*3303.00*	*84.30*	*335.39*	*2694.41*	*2579.47*	*1655.07*	*0.00*	*0.00*	*0.00*

SLIDE SHEET (BN-10H)

- Initial Depth interval: 703 m.
- Real Depth interval: 2613 – 3340m (727 m)
- Average DLS 3.54°/30 m @ 18% setting (19.6°/30 m @ 100%)
- Average ROP: 32 m/hr

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FINAL DRILLING DAYS – 8 ½" HOLE SECTION

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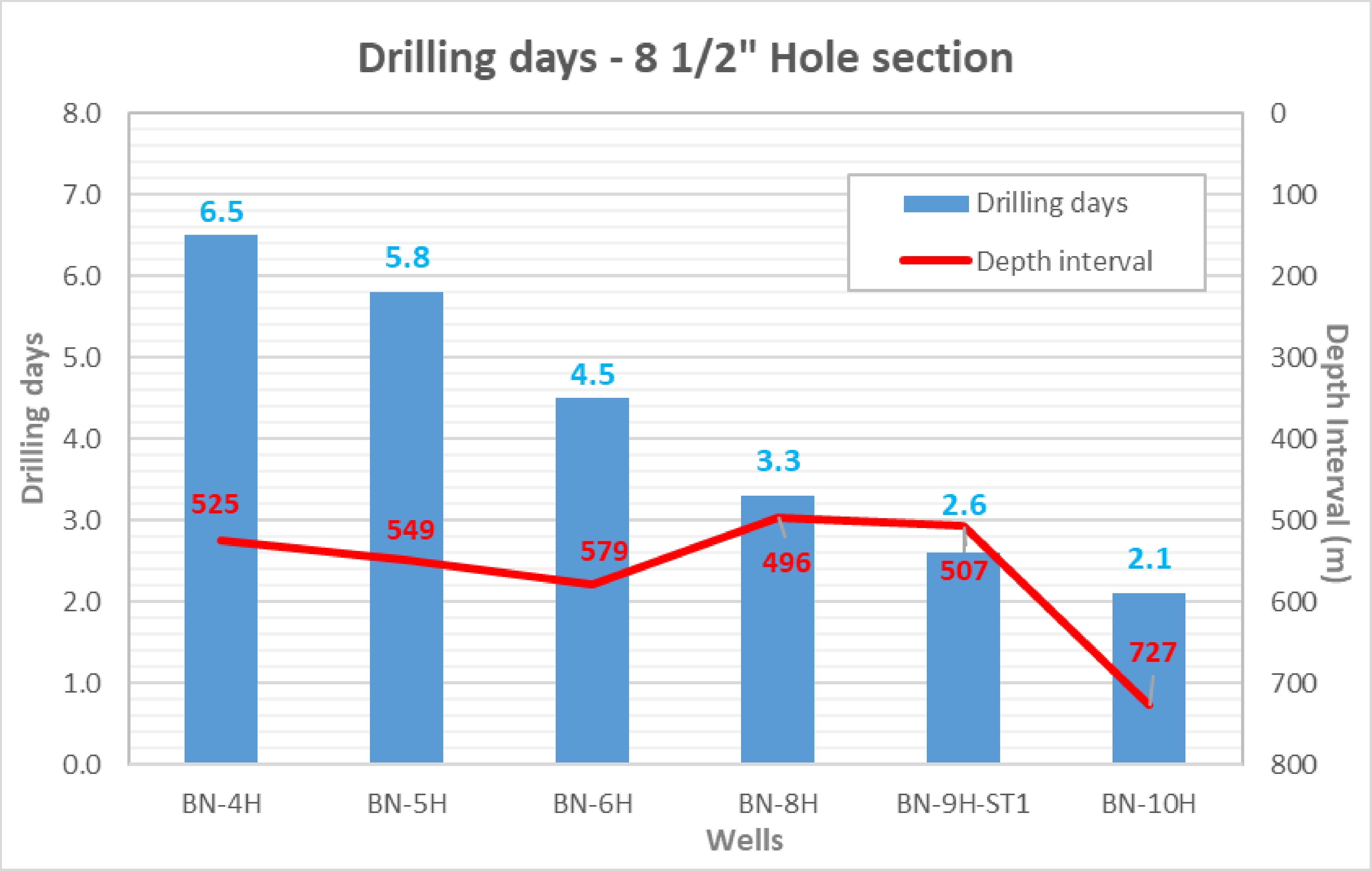

WELLS	% USAGE	
	DHM	POWER DRIVE
BN-4H	78.1	21.9
BN-5H	52.5	47.5
BN-6H	35.2	64.8
BN-8H	36.3	63.7
BN-9H-ST1	0.0	100.0
BN-10H	0.0	100.0

DHM & Power drive X6

Power drive Archer

NORMALIZED DAYS – 8 ½" HOLE SECTION

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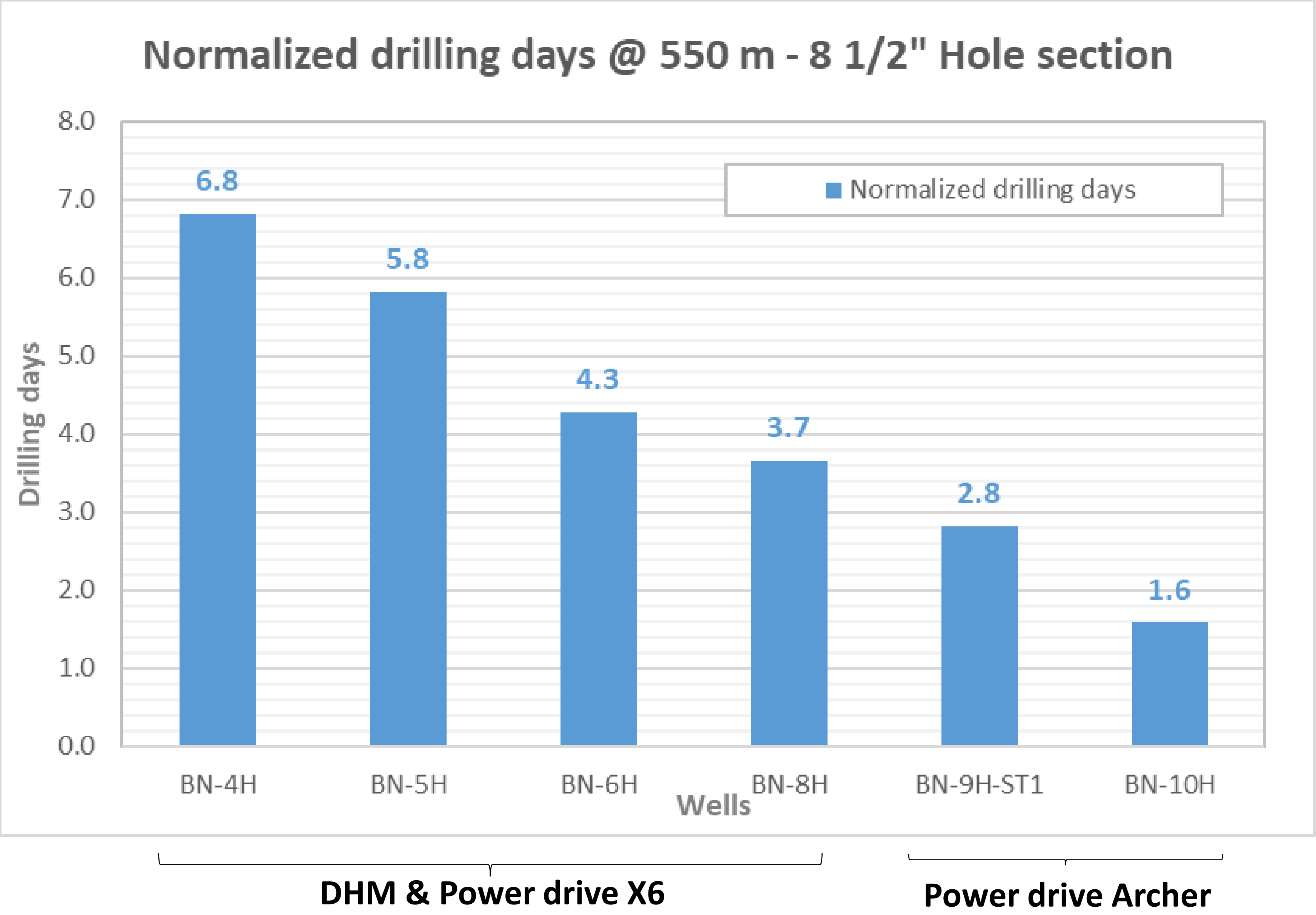

DRILLING OPTIMIZATION– 8 ½” HOLE SECTION #FEXenergía

- **Depth Interval of 550 m**
- **Well BN-8H (Use of two BHA´s)**
- **Best normalized drilling days - 8 ½” hole section -** 3.7 days

- **Well BN-10H (use of only one BHA)**
- **Best normalized drilling days - 8 ½” hole section -** 1.6 days

- **Drilling optimization for a depth interval of 550 m in 8 ½” hole section:** 3.7 – 1.6 = **(2.1 Days)**

SAVED DAYS AND MONEY 8 1/2" HOLE SECTION - 550 m	
DAILY DRILLING COST (USD)	235,000
DRILLING DAYS EFFICIENCY	2.1
AMOUNT (USD)	493,500
TECHNOLGY INVERSION - DIFFERENCE (USD)	75,000
NET SAVED AMOUNT (USD)	418,500
# WELLS PER YEAR	5
TOTAL SAVED AMOUNT PER YEAR	**2,092,500**
# TOTAL DAYS IN ADVANCE	**10.5**

WELL DESIGN AND FINAL BHA PROGRAM

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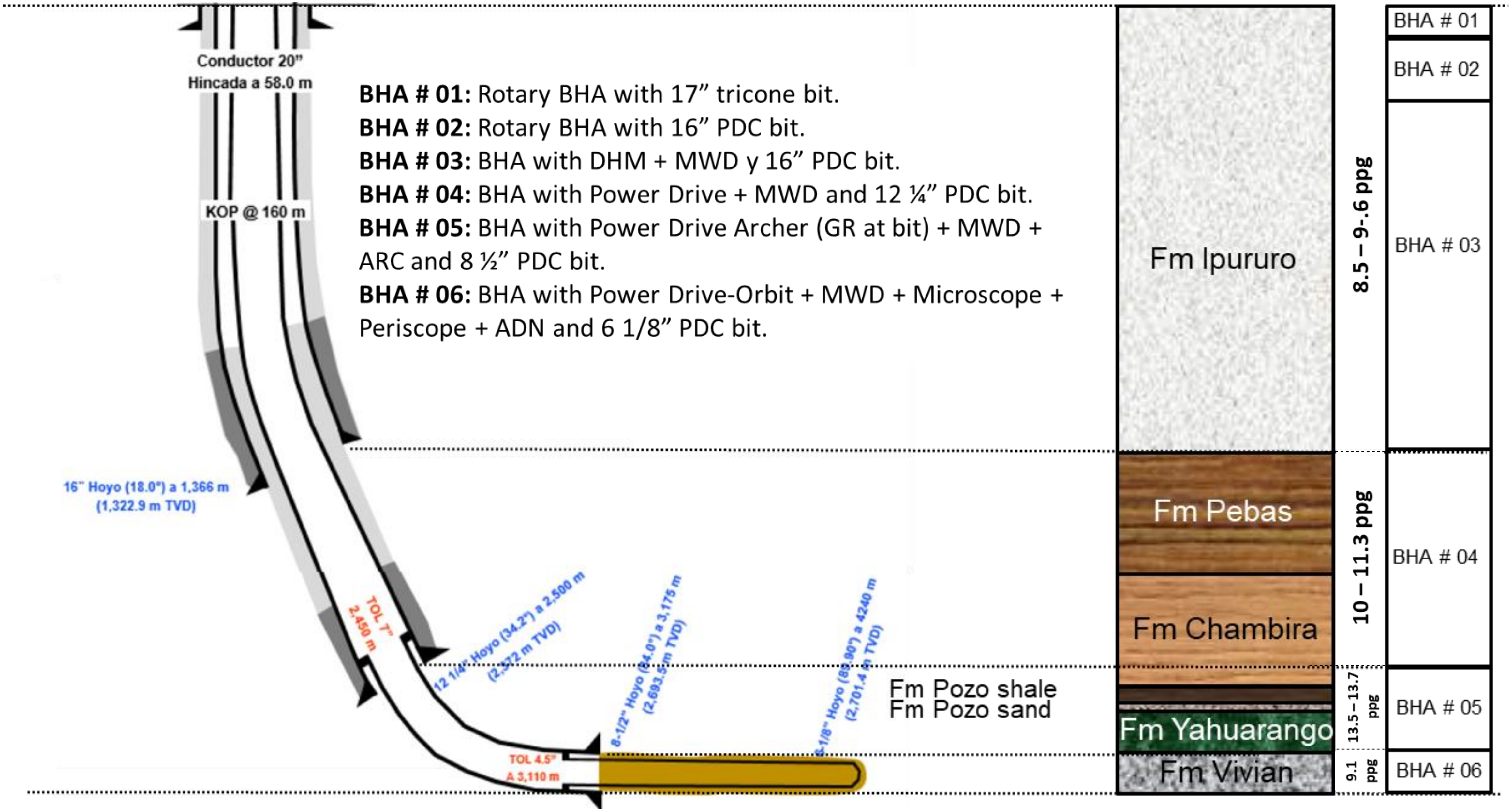
BHA # 01: Rotary BHA with 17” tricone bit.
BHA # 02: Rotary BHA with 16” PDC bit.
BHA # 03: BHA with DHM + MWD y 16” PDC bit.
BHA # 04: BHA with Power Drive + MWD and 12 ¼” PDC bit.
BHA # 05: BHA with Power Drive Archer (GR at bit) + MWD + ARC and 8 ½” PDC bit.
BHA # 06: BHA with Power Drive-Orbit + MWD + Microscope + Periscope + ADN and 6 1/8” PDC bit.



CONCLUSIONS

- Performance of power drive archer shows 2.1 days less per well compared to the use of two BHA´s generating a net saved amount of 418 MUSD per well

- For a regular drilling campaign (5 horizontal wells per year), it represents a reduction in drilling days and costs savings of 10.5 days 2.1 MMUSD respectively

- Anticipated oil production with an average of 8,000 BOPD due to drilling days saved

RECOMMENDATIOS

- Continuous improvement to manage power drive settings to increase ROP

- Previous training for personel involved to introduce new techologies

Disclaimers

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FEX ENERGÍA QUE TRASCIENDE

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; the Company’s ability to operate in accordance with developing public health efforts to contain COVID-19; potential exploration and development opportunities, including drilling five additional wells and one water disposal well pursuant to the Company’s 2022 development program; 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; future production levels and growth, including 2022 cash flow; debt; 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.

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 may contain 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, 2021 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, 2021 (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.

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.

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

This presentation may contain 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 cash flow" defined as EBITDA before hedging minus CAPEX. "Free cash flow after debt service" defined as EBITDA less interest and CAPEX (all estimated). "Yield" means free cash 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.

FEX

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2022