PetroTal

An Overlooked Spin-off

17 December 2019

Investment Type: PetroTal is a Type 1 “Spin-off”

Type 1: Wonderful Company – Fair Price

- Lasting «moat»
- Great management
- Solid balance sheet
- Consistently high return on invested capital (ROIC > WACC)
- Fair price

Type 2: Fair Company – Wonderful Price

- Good company, potentially with a «moat» or temporary advantage;
- Uncertain management
- Solid balance sheet
- Potentially short term issues
- Cheap
- Needs a catalyst

Type 3: Special Situation

- Spin-off; de-leveraging
- Small-cap without research coverage
- New listing without research coverage;
- Misunderstood hidden reserves
- «Cyclical» cheap (low earnings in the cycle, low share price);
- Merger arbitrage

Type 4: Short Investment

- Fraud; Regulatory issues;
- Mismanagement (e.g. M&A)
- Commodity price collapse;
- Demand collapse;
- Structural over-supply
- Nota bene: «needs external catalyst»

Source: Burggraben Holding AG (BGH) analysis

Company Snapshot

Basics

- Style Factors:
  - Sector: Energy / Production of Oil
  - Beta: 1.762;
  - Leverage: zero (net cash position)
  - Geography (earnings exposure): Peru; Brent oil price
- Visibility: Toronto & London Exchange (AIM)
  - TAL CN Equity (Bloomberg); PTAL LN Equity
  - IFRS accounting; quarterly reporting
- Capitalisation & Liquidity (18/08/2019)
  - EV: US$ 181m; Market Cap: US$240m
  - Number of shares (fully diluted): 704,282,185
  - Free Float: 54%
  - Liquidity: CAD 6.7m traded between Jan – May 2019
- Ownership/Governance:
  - Gran Tierra 46%; Mgmt about 5%;
  - PetroTal is a spin-off of Gran Tierra in 2017, through a merger with Sterling Resources;
- Catalyst:
  - Production growth: 4,000 to 10,000 b/d within 6 months;
  - Global economy shifting from "Quad 4 to 3" in H2 2019;
- Key Risks:
  - Reservoir performance of Bretaña asset;
  - Liquidity in 2020; Development & operational risks;
  - Commodity price risk to Brent, i. e. "more Quad 4" in H2 2019 due to global recession/deflation

Share Price (in CAD/share, 16/12/19)

Investment Strategy

Investment	Buy Ordinary Shares
ISIN	CA71677J1012
Estimated Holding Period	3-5 years
Catalyst	Production growth
Reaction on share price collapse	Accumulate, unless fundamentals have changed
Leverage	0%
Currency Hedge	100% of USD/GBP risk (for UK listing)
Market & Cycle Hedge	None

Source: BGH analysis; Bloomberg

Executive Summary: «An Overlooked Spin-Off»

- One-Field Company: PetroTal is a small-cap independent oil & gas company domiciled in Canada with corporate offices in Houston, Texas. The company's operation is centred in Peru. Its main focus is to develop the Bretaña field in Block 95 and to explore & develop the Osheki prospect in Block 107, both located in the Peruvian Amazonian. Today, the company is dual listed in Toronto and London with a fully diluted market cap of US$ 240m.
- Spin Off: In 2017, Sterling Resources, a listed company with $41m cash but no assets, and PetroTal, a company with a credible local management but no assets or listing, merged and entered into a agreement with Gran Tierra to buy its Peruvian assets in exchange for issuing shares to Gran Tierra. PetroTal effectively is the spin-off from Gran Tierra's Peruvian subsidiary. The latter now holds 46% of PetroTal.
- Production & Reserves: As at 16 December 2019, PetroTal produces approx. 9,000 medium-heavy barrels per day from the Bretaña asset, a conventional sandstone reservoir in which it holds 100% working interest and which it operates. The field holds 39.8 Mmbbl of Proved and Probable Reserves (2P) net to PetroTal. Today, the reservoir is well defined from 7 wells, of which 5 are producing. Going forward, management aims to exceed an exit rate of 12,000 bpd of production by year-end 2019. Base case, we forecast PetroTal to briefly exceed 20,000 bpd in 2021 (average of 14,600 bpd for the year) from up to 11 production wells and with the support of 3 water disposal wells.
- Low Cost Asset: Once fully developed, Bretaña will produce at lifting cost of US$10/barrel (US$ 12/bbl incl. G&A). Over the life of the field and including transportation tariffs, royalties and after crude quality discounts for its medium-heavy oil (API 19.4), we forecast Bretaña to generate US$28/barrel of pre-tax free cash flow at a Brent price deck of $65/barrel. To do so, PetroTal is going to invest US$ 333m or about US$8.4/barrel to generate returns of 93% on its invested capital. A profitable business indeed (link).
- Benefit from Sunk Cost: Between 2009-2017, Gran Tierra invested approx. US$ 390m into Bretaña's development. This is important for an investor into PetroTal for two reasons: Firstly, PetroTal became owner of a high quality oil asset in Peru that was geologically largely de-risked as Gran Tierra's four well drilling campaign substantially confirmed the volumetric of the reservoir. Within the sector, this is major – not minor. Secondly, it provided PetroTal with a tax asset of US$ 310m as at 31 December 2018. Combining the two, PetroTal's shareholders became beneficiaries of a substantially improved, risk-adjusted return on invested capital. We illustrate this here.
- Fully Funded? Due to the merger with Sterling Resources and following a capital raise of GBP 20m (US$ 25m) in May 2019, PetroTal has the necessary funding to develop the Bretaña asset. As at June 2019, the company has zero debt and a pro-forma liquidity US$ 58m. However, subject to oil prices and the payment terms of the ongoing development program, the cash generated from its full year average production forecast of 4,600 bpd on average in 2019 may not be sufficient to fund the drilling campaign. PetroTal may require a working capital facility to bridge a potential liquidity shortcoming in 2020. This is because oil sold to Petroperú is in transit for up to 180 days. Alternatively, PetroTal may address any liquidity shortage by establishing a factoring facility, given the quality credit of Petroperú. We also understand the payment terms for the drilling service company to be addressable. Either way, the company is well positioned to install a working capital facility once the new, likely revised CPR report is out in Q1 2020 to fund any shortcomings and once the production program is ramped back up after some maintenance work in January.

Source: BGH analysis; Note: bbl = blue barrel; Mmbbl = million blue barrels; 2P = Proved & Probable; bpd = barrels per day

Executive Summary: «An Overlooked Spin-Off»

- It Gets A Lot Better: A geologist's way to estimate how much oil a field may yield is to assume a recovery factor on the fields Original Oil in Place (OOIP). The former is based on various factors such as oil gravity, reservoir porosity or its permeability. Bretaña's 2P reserve assumption is for 330 Mmbbl OOIP and a recovery factor of 12% for Netherland, Sewell & Co (NSAI), the author of the reserve report and auditor of the field, to derive 2P Reserves of 39.8m barrels. However, based on other in-country analogue fields, the recovery factor used by the report seems conservative – we mean ridiculously conservative.
- Going the Extra Mile: With the help of management and Petroperú, one of two state-owned oil & gas bodies of Peru, we have studied 16 analogue in-country fields within the same basin. The "same basin" is industry lingo for comparing apples with apples. The selected fields had a total of 2.5 billion of Original Oil in Place (OOIP) and produced 665 Mmbbl crude oil for a weighted average recovery factor of 27%. Is the CPR too conservative?
- API Matters Too: Bretaña produces medium-heavy, low sulphur crude with 19.4 API gravity, a measure of the crude's quality for its end user - the refiner. The lower the API, the heavier the oil, the more process intensive the refining of the oil becomes (and hence why there is usually a discount for heavier oil at the well-head). Our analogue field work reveals that oil gravity appears to have the greatest impact on the recovery factors. In general, the lighter the gravity of the oil, the higher the recovery factor; and it shows larger fields have slightly higher recovery factors than smaller fields.
- Drilling Deeper: More concretely, our work illustrates that the most relevant analogue fields yield recovery factors of more than 35% and that all medium crude fields have recovered 32%. This is important because the CPR used a lower API of 18.5 for Bretaña as it did not have the confirmation of its quality back in 2018. So yes, the CPR was conservative but also had to work with incomplete data.
- More Oil in Place? Meanwhile, Bretaña is producing oil every day at stable rates of between 750 and 8,250 bpd from 5 wells. The reported data from its first two horizontally completed production wells in 2019 suggest, among others, IP Rates of >6,000 barrels per day and 13% more net pay - a measure of the economically producible hydrocarbon thickness of a reservoir. On that basis, Bretaña may well have 45 Mmbbl more oil in place or a total of 380 Mmbbl.
- Common Sense Approach: Combining more OOIP and a higher recovery factor, Bretaña may well have 91 MMbbl of 2P reserves or 2 times more oil to be sold! Of course, it is early days and we are not suggesting a reserve revision by year end. But we are suggesting that paying attention to data and applying common sense and independent thinking does help buying low and ahead of the crowd, especially if the base case outcome would be just fine, too!
- Valuation: Base case, our Core-NAV of CAD 0.9/share suggests 113% upside from today's share price of CAD 0.43/share at a Brent price deck of $65 flat (link). Modelling out a 24% recovery factor on 380 Mmbbl OOIP - which requires 7 additional producing wells and 3 more water injectors - will add CAD 1.8/share to our Core-NAV for a total upside of 4.3x today's share price (link). This leaves an even higher recovery factor, the Osheki prospect, and/or a higher Brent prices in the future as further upside potential, allowing an informed investor to potentially generate significant risk-adjusted returns on his or her invested capital (link).

Source: BGH analysis; Note: bbl = blue barrel; Mmbbl =m blue barrels; 2P = Proved & Probable; bpd = barrels per day

Executive Summary: «An Overlooked Spin-Off»

- What it comes down to: Such upside has risk. But in our view, far less risk than buying any fashionable "disruptor" at sky high valuations and with significant cash burn on the justification of profitable growth at some uncertain point, but then into perpetuity. At PetroTal, the risks are much more mundane. They mainly revolve around execution - not reservoir - and can be addressed every single day by a competent management team. For instance, in the risk section we illustrate the optionality for transportation in case of renewed pipeline downtime, in our view the main execution risk. In other words, what it comes down to is "management, management and management".
- Management: So who manages PetroTal? The CEO since 2018 is Manuel Zúñiga, a petroleum engineer with 30 years of industry experience. Under his watch, BPZ discovered the Corvina field in Peru and delivered oil in less than two years. More importantly, "Manolo", with whom we interacted intensively, is a first class human being and a country insider. He started his career as a junior engineer with Occidental Petroleum (Oxy) where he worked in Block 1-AB, an analogue field of Bretaña. In other words, Manolo understands Amazonian reservoirs and knows engineers who understand Amazonian reservoirs. The latter is obviously more important. As importantly, he was born and raised in Talara, Peru and has established relationships with operators and government bodies in Peru.
- Family Affair: In Latin America, family matters. Manolo's father, Dr. Fernando Zuniga y Rivero, was President & Chairman of the Board of Petroperú until 1979, the local state-owned company. Prior to that, Oxy, under the leadership of Fernando, was awarded Block 1A - now better known as Block 192 and an analogue field of Bretaña. In 1972, Oxy reported its first discovery. Block 192 produced until 2017. We think most casual researchers do not understand the relevance of this family legacy for the success of Bretaña. Well – we do!
- Trust, but Verify: We did not stop there: we visited all relevant authorities, the PetroTal team in Lima, the field in the Amazonian and met with board members. We also studied countless country, asset and research reports and spoke with high calibre industry analysts, such as Ian Macqueen from Eight Capital based in Toronto, in our view THE expert for Latin American oil & gas producer. The synthesis of our work over the past 18 months is outlined in detail in this paper.
- Our Most Important Message: **We at Burggraben buy firms, not stocks**. What that means is that we look at a company through the lenses of an industrialist, not a hedge fund manager. The latter, in our view, buys stocks in the expectation of them going up tomorrow. Sadly, we do not have such magic touch. We do not know if PetroTal's share price will go up or down tomorrow. But what we do know is that if we buy into a high potential asset with world-class management at a deep discount to its intrinsic value, our loyal clients will be rewarded with superior risk-returns over the long term as the market catches up with its free cash flow realities. To do so, we go the extra mile and hence we are certain that this is a unique risk-reward project in the E&P industry worldwide (yes, we mean that as we looked at dozens of them in much the same detail). Manolo, a high integrity leader with a quality team, will manage this reservoir and the country-specifics with the necessary attention to detail so that PetroTal delivers the oil safely, on time & on budget – for the benefit of shareholders.

The Company

Why We Invested in PetroTal

PetroTal offers a superior risk-return profile due to a combination of factors:

1. Growth: PetroTal will increase production up to 3x by 2021 (from 10kbpd)
2. Cheap: NAV; EV/Reserve; EV/Flowing Barrel; Oil Price
3. Low Risk: Low Cost; Low Development Risk; Zero Exploration Risk
4. Upside: Development of 3P Reserves (from 12% to 30% recovery rate)
5. Mgmt: Excellent relevant technical knowledge & local network

Source: BGH analysis;

Capitalisation

PetroTal has a fully diluted market cap of US$ 238m as at 17 December 2019 and a pro-forma Enterprise Value of US$ 179m. It has zero debt and a net cash position of approx. US$ 58m as at June 2019.

Market Cap & Enterprise Value

Capitalisation		17/12/2019	Comments
Ordinary Shares Outstanding YE		537,740,991	31 December 2018
Performance warrants		26,750,000	31 December 2018
Compensation warrants		2,086,500	31 December 2018
Performance stock units		4,371,361	31 December 2018
Capital Increase June 2019		133,333,333	03 June 2019
Fully diluted number of shares		**704,282,185**	
Share Price	CAD	0.4400	
FX: USD CAD		1.3000	
Share Price	US$	0.3385	
Market Cap	US$	**238,372,432**	
Debt: banks, bonds, leases	US$	0	30 June 2018
Cash & equivalent	US$	26,259,000	30 June 2018
VAT receivables	US$	6,848,000	30 June 2018
Rights Issue	US$	25,400,000	03 June 2019
Cash (Net Debt)	US$	**58,507,000**	
Enterprise Value	US$	**179,865,432**	

Source: BGH analysis, Bloomberg;

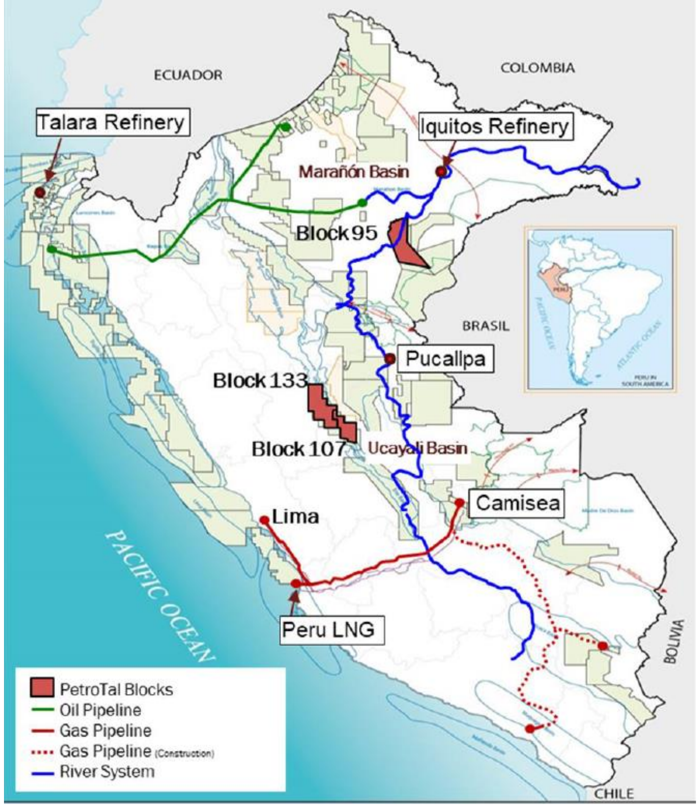
Company Portrait

PetroTal owns 100% of a material, high quality, low risk oil development asset in Block 95 in Peru, better known as the Bretaña field.

The Basics & Recent History

- One-Field Company: PetroTal is a small-cap independent oil & gas company domiciled in Canada with corporate offices in Houston, Texas. The company's operation is centred in Peru. Its main focus is to develop the Bretaña asset in Block 95 and to explore and develop the Osheki prospect in Block 107. Today, the company is dual listed in Canada and the UK.
- Production & Reserves: Currently, PetroTal produces about 3,000 bpd from the Bretaña asset, a conventional oil field in which it holds a 100% working interest and which it operates. The field holds 39.8 Mmboe of 2P reserves net to PetroTal. Going forward, management aims to exceed an exit rate of 10,000 bpd of production by year-end 2019.
- Spin-off: The company effectively is the spin-off from Gran Tierra of its Peruvian assets. Gran Tierra invested approx. US$ 390m in the Bretaña asset between 2009 and 2017. With Colombia as its main asset hub and in the context of the 2014-2016 oil price collapse, no more capital was allocated to Peru. In 2017, a new management team at Gran Tierra decided to dispose of the Peruvian subsidiary.
- More History: On 9 November 2017, Sterling Resources, a listed company with $41m cash but no assets, and PetroTal, a company with an experienced local management but no assets or listing, merged and entered into an agreement with Gran Tierra to buy its Peru assets in exchange for issuing shares to Gran Tierra. This left Gran Tierra with 47% of PetroTal. The result was that the newly named PetroTal (formerly Sterling Resources) became owner of a high quality oil portfolio in Peru, US$ 310m tax losses carried forward and a high quality management team to develop the assets in a resourceful manner.
- Fully Funded: As important, following a recent capital raising of GBP 20m (US$ 25m) the team has the necessary liquidity (including liquidity from former Sterling Resources) to develop the Bretaña assets while having access to public markets through Sterling's Toronto listing.

Area of Operation



 Source: BGH analysis, company filings; Note: bpd = barrels of oil per day; Mmboe =m barrels of oil equivalent;

Balance Sheet

PetroTal does not have debt. Before long-term VAT receivables, it has US$ 58.5m in cash & cash equivalents. It carries the Bretaña field at US$ 52m in its books.

Pro-Forma Balance Sheet (as at 30 June 2019)

Pro-Forma June 2019	US$m	US$m	
Current Assets:			**Current Liabilities**
Cash	51.7	7.5	Trade Payables
VAT receivables	6.8	0.0	Deferred Income Tax
Trade Receivables	1.8	2.1	Decom Obligations
Inventory	0.2		
Prepaid Expenses	0.5		**Non-Current Assets:**
	61.0	9.0	Decom Obligations
		18.6	
Non-Current Assets:			
Exploration Asset	4.7		**Equity:**
PP&E	52.0	110.2	Share Capital
Deferred Income Tax	0.8	0.1	Contributed Surplus
VAT receivables LT	2.9	(7.4)	Deficit
	60.5	**102.9**	
Assets	**121.5**	**121.5**	**Liabilities & Equity**
Net Cash	**58.5**		

Source: BGH analysis; Company filings; Note: PetroTal completed a capital increase of US$ 25.4m in June 2019

Sunk Cost & Tax Asset

Gran Tierra likely invested about US$ 390m over 8 years into exploring & developing the Bretaña field in Peru. PetroTal's shareholder benefit from this directly, both in terms of having its main asset de-risked substantially from 4 field-delineating new wells (link) as well as from a reported off-balance sheet tax asset of $310m as at 31 December 2018.

Sunk Cost

Gran Tierra Capital Program in Peru US$ million	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Peru Capital Program	**1.6**	**15.0**	**36.2**	**62.9**	**83.0**	**174.2**	**45.0**	**6.0**	**4.5**	**428.4**
of which										
Farm in		2.0		5.4						7.4
Infrastructure / facility				12.5	1.5	8.2	10.0			32.2
Drilling				31.1	42.9	111.7	19.0			204.7
Geological & Geophysical				12.0	34.8	37.7	16.0			100.5
Other			15.0	1.9	3.8	16.6		3.0	2.0	42.3
Block 95 - Bretana field	**0.0**	**2.0**	**15.0**	**62.9**	**83.0**	**174.2**	**45.0**	**3.0**	**2.0**	**387.1**
Blocks 106, 107, 128, 133										41.3

Source: BGH estimates & analysis; Company filings Gran Tierra

Reserve Report Block 95

The Competent Person Report (CPR) by NSAI suggests 2P reserves of 39.8m barrels of oil for Bretaña with a NPV of US$ 405m at a recovery factor of 12%.

Block 95 (Bretaña): Reserve Report (in '000 bbl and US$m)

	Category	Oil Reserves[1] (MBBL) Gross	Net	Future Net Revenue[2] (M$) Total	Present Worth at 10%
	Proved Undeveloped	15,271.0	15,271.0	150,435.3	93,522.6
	Probable Undeveloped	24,488.3	24,488.3	563,055.6	311,540.8
2P Reserves	Proved + Probable	39,759.3	39,759.3	713,490.9	405,063.4
	Possible Undeveloped	39,522.7	39,522.7	1,357,866.6	590,627.4
	Proved + Probable + Possible	79,282.0	79,282.0	2,071,357.4	995,690.8

Totals may not add because of rounding.

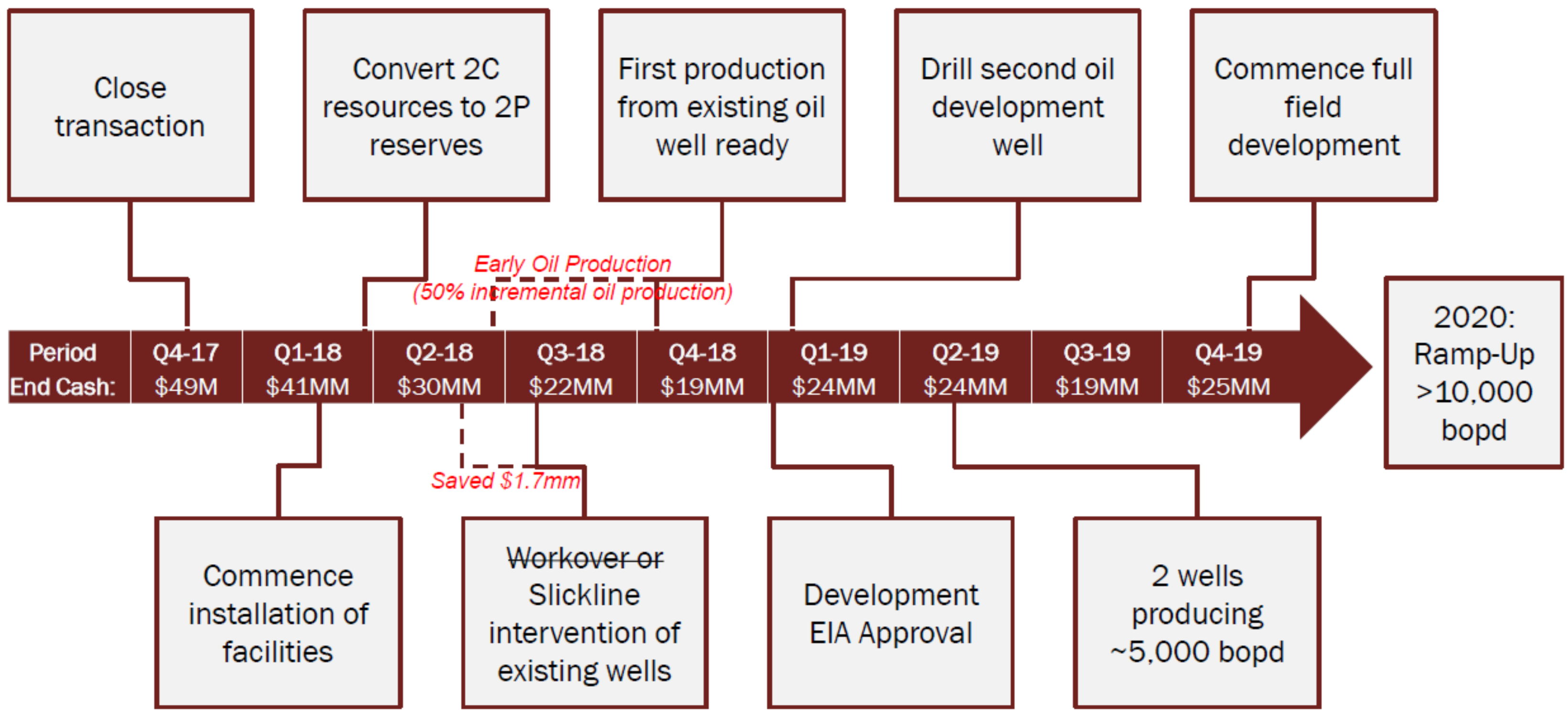
(1) PetroTal owns a 100 percent working interest and 100 percent net revenue interest in these properties.
(2) Future net revenue includes deductions for PetroTal's sliding scale government royalty payments.

Source: CPR 2018 by Netherland, Sewell & Associates, Inc., page 35 (NSAI)

Development Timeline

Bretaña is on track for an exit production rate of >10,000 bpd in 2019.

Timeline

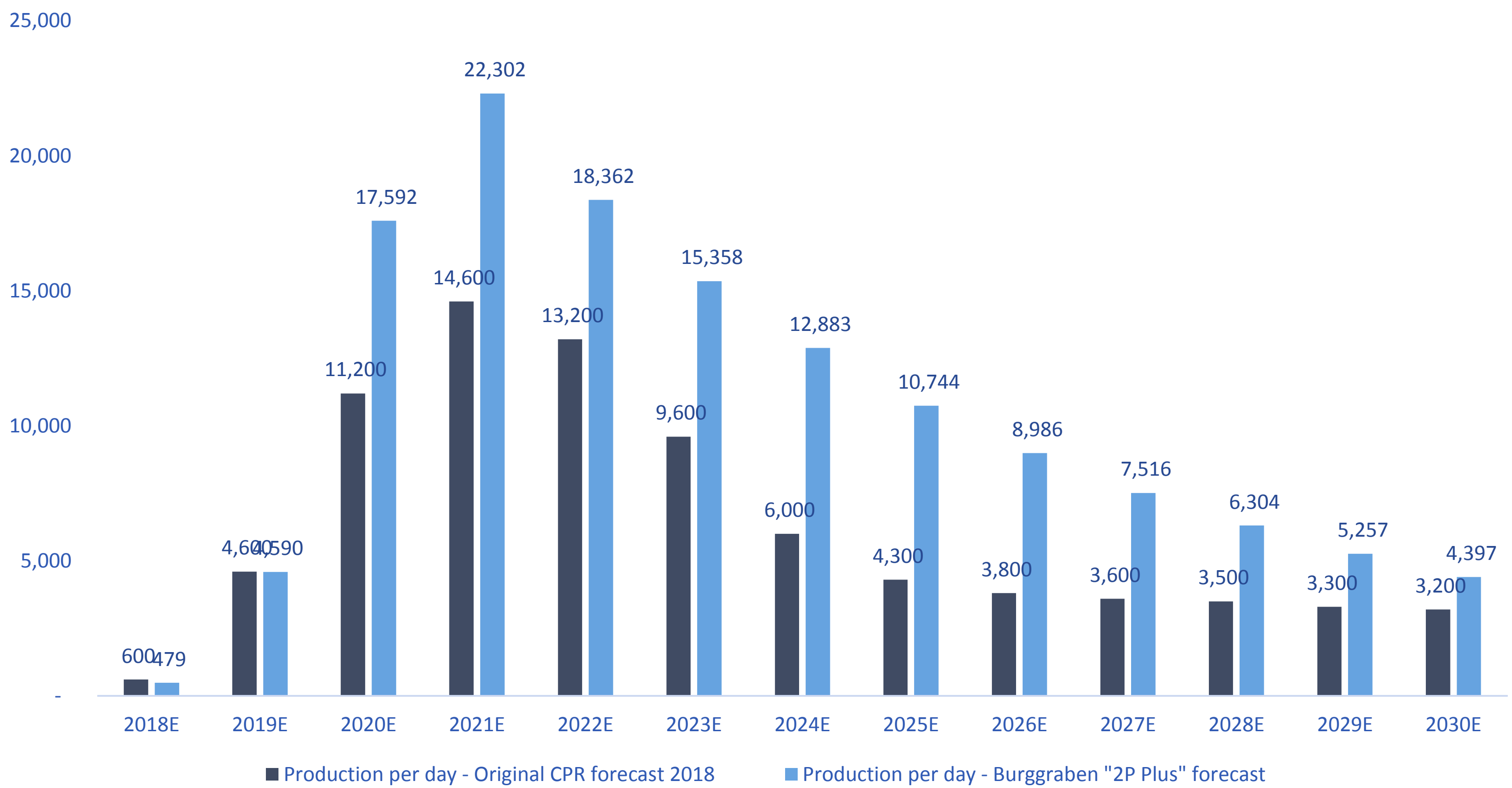


Source: Company filings

Production Forecast

Our production forecast averages 17,592 barrels per day (bpd) in 2020 from 11 producing wells. This is 60% more than the CPR of 11,200 bpd due to an accelerated drilling campaign and the outstanding results of the two completed horizontal wells reported so far in October & December 2019. Our forecast assumes a shut-off in 2037.

Production Forecast (in barrels per day): Base Case “2P Plus” Forecast



Source: BGH analysis; company filings; Note: bpd = barrels per day; CPR = Competent Person Report = Reserve Report

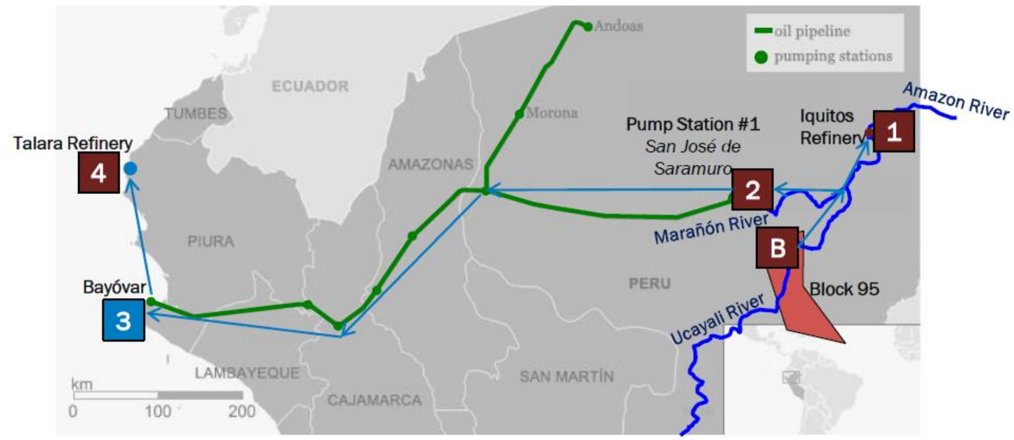
Transportation

The early production system sells its oil into the Iquitos refinery. Production over and above 1,000 barrels a day is barged and piped to the Talara refinery at the East coast.

Assessment

- The initial 1,000 bbl per day are sold into the Iquitos refinery;
- The oil is transported with barges to the refinery for $5.50/bbl;
- A Ucayali River barge has a maximum capacity of 20,000 barrels;
- With full production, oil will be barged to the Pump Station 1 at an estimated cost of $3.50/bbl.
- The Northern Oil Pipeline then delivers the oil to Bayovar for a tariff of $9/bbl from where it is barged to the Talara refinery;
- For more details, see Transport in this presentation (link).

Illustration



 Source: BGH analysis; company filings

Unit Cost

The Bretaña development is going to generate high risk-adjusted returns for its shareholders at 2P "Plus" reserves of 55 Mmbbl (which are likely far too conservative – see link).

Netback & ROIC (in US$ and %)

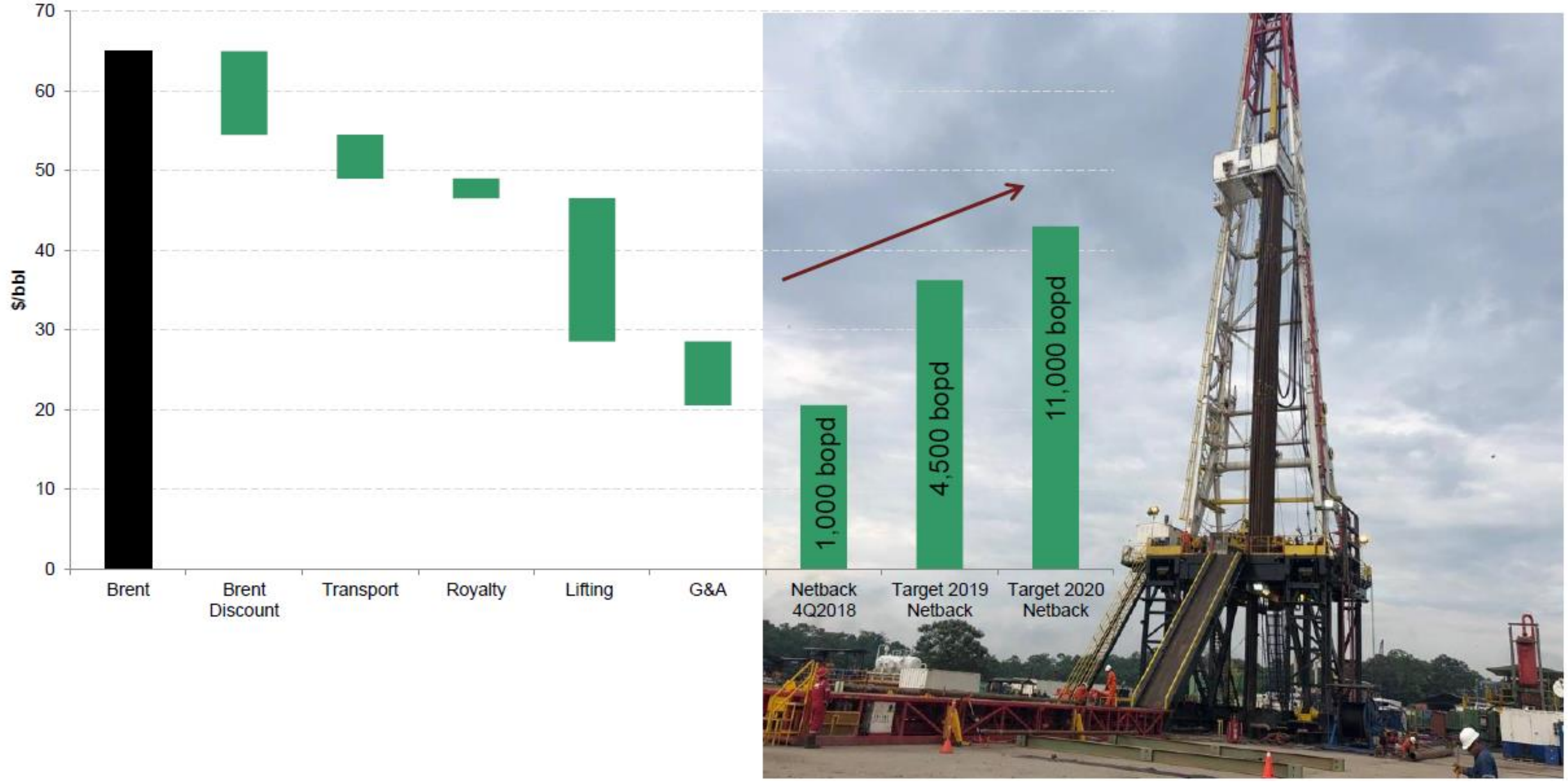
Netback & ROIC: 55 MMbbl		US$/bbl	US$/bbl	US$/bbl	Comments
Brent		55.0	65.0	75.0	
Discount for oil quality	14.0%	(7.7)	(9.2)	(10.5)	API 19.5 (medium oil)
Realised Price at the well head		**47.3**	**55.8**	**64.5**	
Royalty rate	5.0%	(2.4)	(3.1)	(3.2)	on realised price
Barging & Pipeline tariff		(12.7)	(12.7)	(12.7)	transportation to East coast refinery (Talara)
Operating Cost		(11.8)	(11.8)	(11.8)	between $8-20/bbl over the life of the reservoir
Netback (pre-tax)		**20.4**	**28.2**	**36.8**	
Corporate tax rate	32.0%	(8.0)	(11.8)	(13.3)	incl. US$ 310m tax losses & US$300m investment allowance
Netback		**12.4**	**16.3**	**23.5**	
Investment / barrel		(8.5)	(8.5)	(8.5)	$333 million investment (point forward 2018), excl. Apex
Netback (all-in)		**3.9**	**7.9**	**15.1**	
ROIC excluding Sunk Cost		**47%**	**93%**	**178%**	

Source: BGH analysis; company filings

Mgmt Guidance

Management is guiding $10-15 above our base case pre-tax netback of $27/bbl at $65/bbl Brent. We assume this is due to lower lifting and transportation cost.

Mgmt Guidance for Netback with Higher Volumes (in US$/barrel)

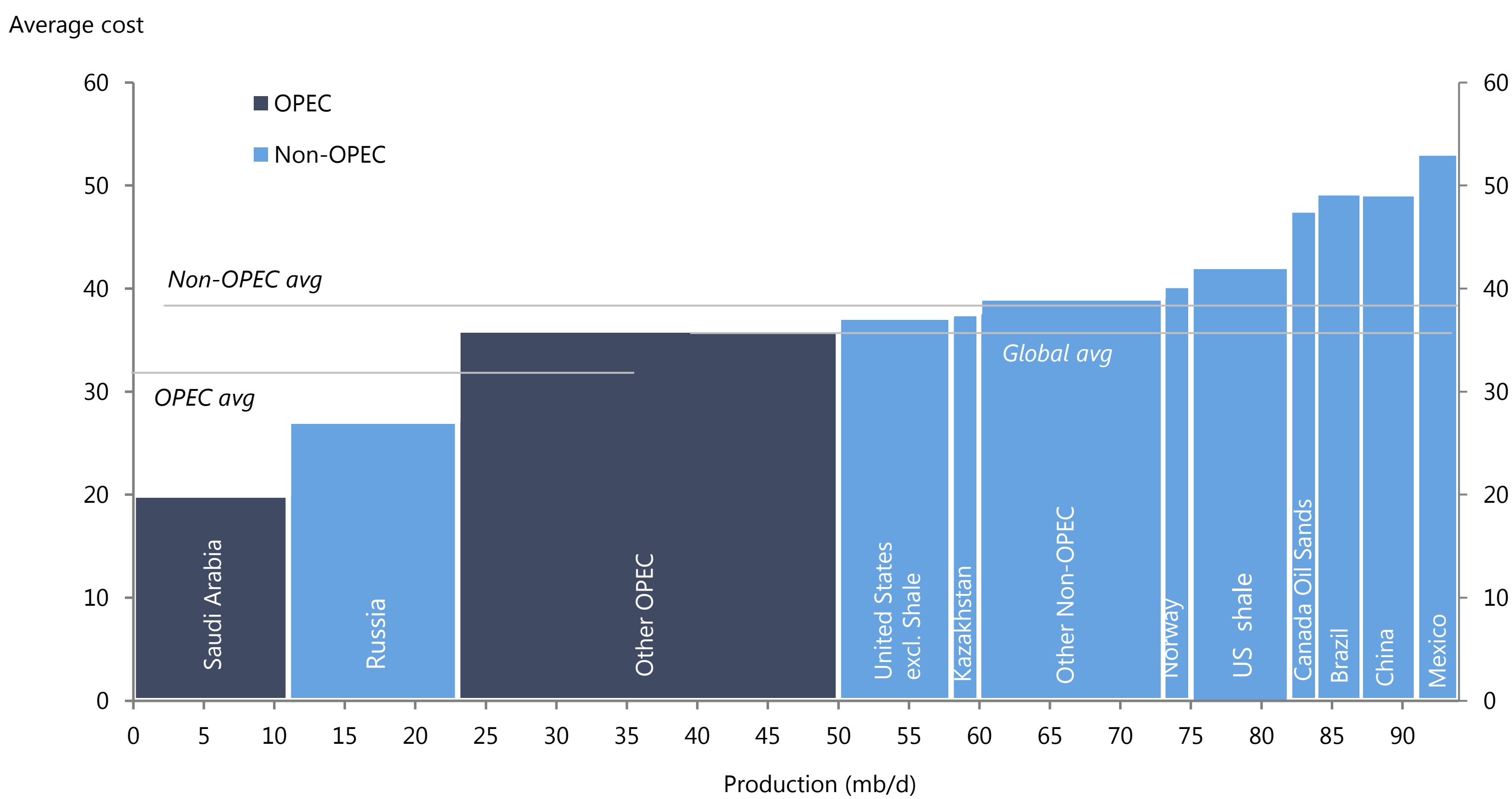


 Source: Company filings, May 2019

Global Cost Curve

Excluding corporate taxes & well-head discounts (for comparison), PetroTal's full cycle cost of $29/bbl puts it in the lower quartile of the world cost curve.

Global Cost Curve (in US$ per barrel of oil)

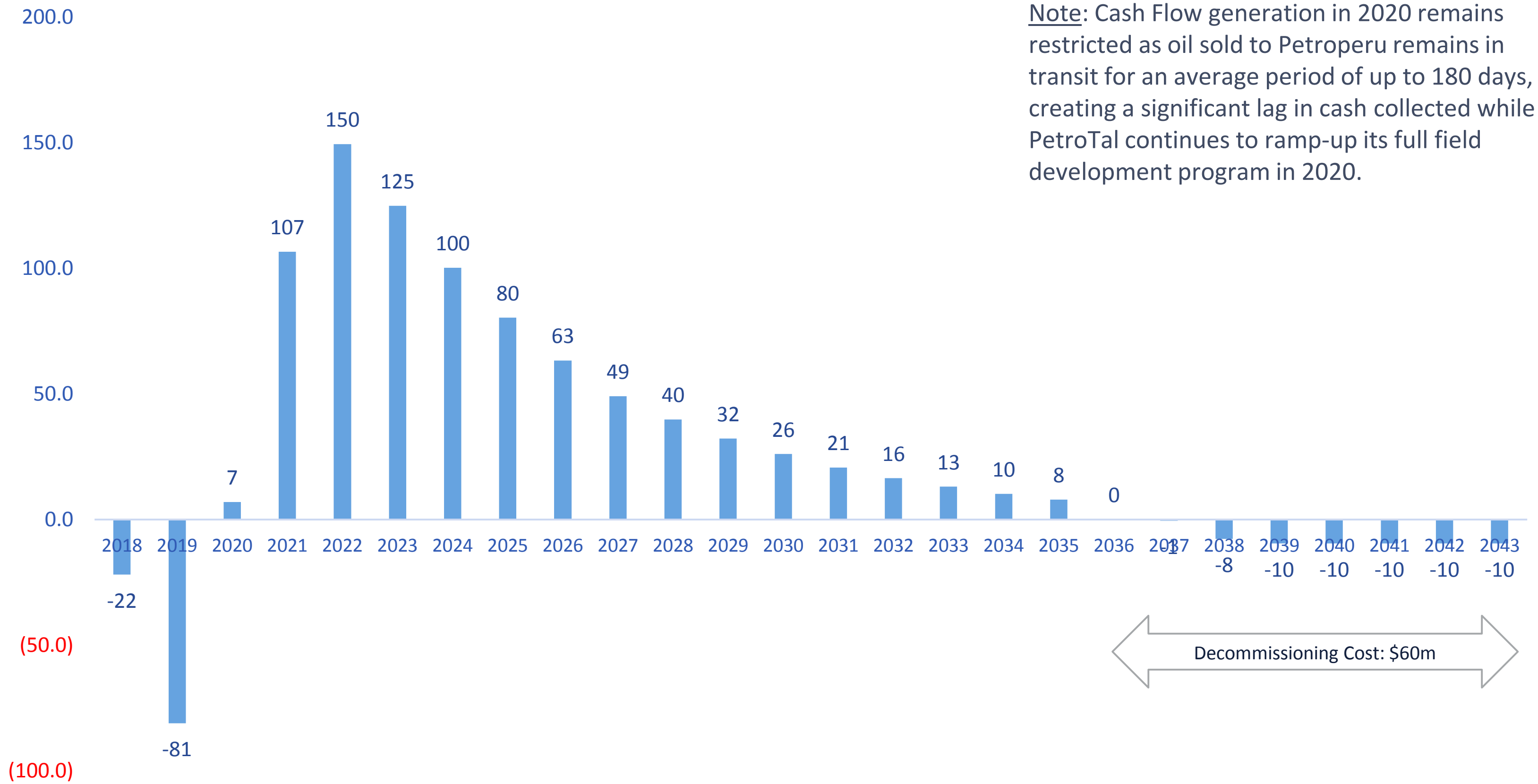


Source: Energy Aspects for BGH, June 2019

Strong Free Cash Flows

Base case, we forecast the company to generate US$ 792m in “point forward” free cash flow from the Bretaña field as of today. We forecast first free cash flow of US$ 7m in 2020 at $65/bbl Brent and subject to a factoring facility to collect revenues from PetroPeru early.

Cash Flow Profile (in US$m): Base Case -> 55 MMbbl 2P “Plus” Reserves



Note: Cash Flow generation in 2020 remains restricted as oil sold to Petroperu remains in transit for an average period of up to 180 days, creating a significant lag in cash collected while PetroTal continues to ramp-up its full field development program in 2020.

Source: BGH analysis; company filings; Note: US$ 65 Brent price deck; 16.7% recovery rate on 330 Mmbbl OOIP

Putting It All Together

Based on today's valuation and assuming no dividend payment, we forecast the company's cash position to surpass today's market cap in Q4 2022.

Historic & Forecast Results – Base Case (US$ million, unless otherwise indicated)

Summary		Total	2017	2018	2019F	2020F	2021F	2022F	2023F	2024F
Reserves & Production:										
2P Plus Reserves: 55 Mmbbl	MMbbl		39.6	39.4	45.2	46.3	43.2	36.5	30.9	26.2
Production	**bpd**		**0**	**479**	**4,590**	**17,592**	**22,302**	**18,362**	**15,358**	**12,883**
Growth (Decline Rate)	in %				858%	283%	27%	-18%	-16%	-16%
P/L, Balance Sheet & Cash Flows										
Revenues (after royalties)	US$ million		0.0	9.7	89.0	341.0	432.3	355.9	297.7	249.7
EPS	US$ / Share		(0.00)	(0.01)	0.05	0.21	0.26	0.20	0.15	0.12
Cash & Cash Equivalent (Short Term Debt)	US$ million		48.7	27.0	(28.6)	(23.3)	83.5	233.8	360.3	462.6
Free Cash Flow	**US$ million**		**(0.4)**	**(21.9)**	**(81.1)**	**7.0**	**106.6**	**149.5**	**125.0**	**100.3**
Unit Analysis:		Over 2P Life:								
Price Deck: Brent	$/bbl	65.0		68.0	65.0	65.0	65.0	65.0	65.0	65.0
Realised Well Head Price	$/bbl	55.8		58.5	55.9	55.9	55.9	55.9	55.9	55.9
Operating Cost	$/bbl	(27.6)		(72.9)	(34.2)	(25.7)	(24.1)	(24.7)	(25.4)	(26.3)
Netback	**$/bbl**	**28.2**		**(14.4)**	**21.7**	**30.2**	**31.8**	**31.2**	**30.5**	**29.6**
Cash taxes paid	$/bbl	(8.5)		0.0	0.0	(6.3)	(8.5)	(9.3)	(9.8)	(9.9)
Capex	$/bbl	(6.0)		(132.7)	(64.2)	(14.1)	(7.8)	(2.5)	(1.0)	(1.0)
Free Cash Flow per barrel	**$/bbl**	**13.6**		**(147.1)**	**(42.5)**	**9.7**	**15.6**	**19.5**	**19.6**	**18.6**
Valuation:										
Market Cap	US$ million			93	238	238	238	238	238	238
Net Debt (Cash)	US$ million			(27)	29	23	(84)	(234)	(360)	(463)
Enterprise Value	**US$ million**			**66**	**267**	**262**	**155**	**5**	**(122)**	**(224)**
EV per barrel of reserves	$/bbl			1.7	5.9	5.6	3.6	0.1	(3.9)	(8.6)
EV per flowing barrel	$/bbl			137,755	58,171	14,872	6,943	247	(7,940)	(17,406)

Source: BGH analysis;

Selected Key People

We interacted with Manolo and Estuardo on a number of occasions. They both made an excellent impression on us. They combine the necessary technical expertise for the development of the reservoir and the local network to manage the cultural context of Peru. We are convinced that the team will deliver.

Senior Management

- Manuel (Manolo) Zuniga-Plücker, CEO PetroTal

  Manuel Zúñiga is a petroleum engineer with 30 years of industry experience. Mr. Zúñiga was a founder and the President and Chief Executive Officer of BPZ when oil was discovered in the Corvina field of the Z-1 Block, brought online in less than two years using the first floating production storage and offloading (FPSO) unit ever in Peru and developed with a buoyant drilling and production platform. Prior to completion of the Arrangement, Mr Zúñiga had been the President and Chief Executive Officer and Chairman of the Managers of PetroTal LLC since January 2016. He started his career as a junior engineer with Occidental Petroleum where he worked in Block 1-AB, located in the northern jungle of Peru. He was born and raised in Talara, Peru and has led exploration and development projects for oil and gas in Peru, as well as other countries in Latin America. He has established relationships with operators in Peru, including owners of the targeted assets, and has good relationships with government agencies in the region. Mr. Zúñiga holds a Bachelor of Science degree in Mechanical Engineering from the University of Maryland and a Masters of Science degree in Petroleum Engineering from Texas A&M University.

- Legacy Context: Manuel Zúñiga's late father, Dr. Fernando Zuniga y Rivero, was President & Chairman of the Board of Petro Peru until 1979. From 1979 until 1996, he was an officer of the energy department at the World Bank in Washington, D.C. From 2004 until 2011 he was Chairman of the Board of BPZ Energy in Houston, Texas. Prior to that, Occidental Petroleum (Oxy), under the leadership of Dr. Fernando Zuniga y Rivero, was awarded Block 1A and Union Oil (Union) was awarded Block 1B (now collectively known as Block 192). In 1972, Oxy reported its first discovery at the Capahuari Field. Block 192 produced until 2017!

- Estuardo Alvarez-Calderon, VP PetroTal

  35 years of oil and gas experience with focus on exploration and new discoveries, and bringing those fields to initial production. Various senior roles across the Americas for Occidental. Former VP of Exploration and Production at BPZ Energy.

- **For more background on the Peruvian team, see link here.**

Source: BGH analysis; company filings; https://www.legacy.com/obituaries/houstonchronicle/obituary.aspx?n=fernando-jose-zuniga-y-rivero&pid=186705098&fhid=32131

Enterepreneurial Approach

An asset like Bretaña, like so many other assets in the world, is not a "self-starter". It needs a resourceful approach or fails to be sanctioned. Helicopter flights into the jungle just don't do it. That is why the "corporate approach" by Gran Tierra failed after 7 years of trying and that is why PetroTal, under the leadership of Manolo, has brought the field online within 7 months…

First Production achieved ahead of schedule and under budget

2017	▪ Closing of acquisition of Gran Tierra Energy International (Peru) Holdings B.V., ▪ PetroTal assumed ownership of Block 95, Block 107, and Block 133
2018	*Q1* ▪ Installation of facilities commenced ▪ 2C resources converted to 2P reserves with NPV of over $400 million at Bretana alone *Q2* ▪ Slickline intervention of existing wells – production commenced June 1 ▪ Facilities for initial production installed and completed on time and under budget by 25% *Q3* ▪ Facilities to allow for water handling installed on time *Q4* ▪ New facilities installed increasing production ▪ Declaration of Commerciality in December 2018 and begin recovery of NOLs
2019 / 2020 Targets	▪ 2019 – by year end – 4 wells online with an exit rate of c.7,200 bopd ▪ 2020 – exit rate of > 10,000 bopd

Start: 9 Nov 2017

7 months

1 Well: 1 June 2018

 Source: Company filings

Valuation

Base Case Assumptions

Key Assumptions

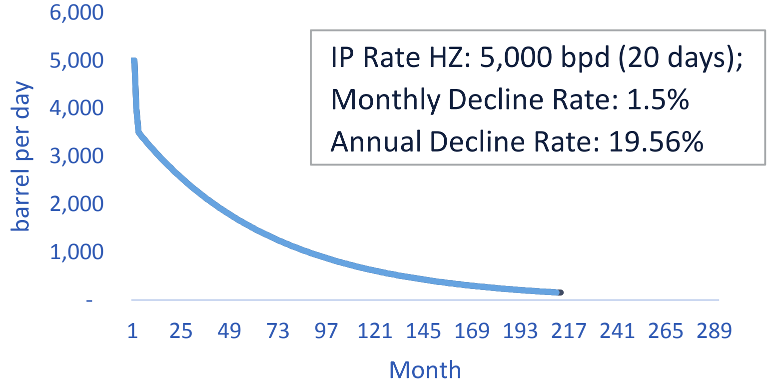
- Production:
  - Base Case: 55m (not 39.6m) barrels of oil produced;
  - From 11 producing wells; 4 water injectors;
  - Drilling campaign completed by December 2020;
  - Water cut: 60% in year 1; 74% in year 2; 81% in year 3; 95% after year 13;

- Capital Program: $333m (pre-apex) = $8.4 / bbl
  - $166m for mobilisation, drilling & completion;
  - $104m for facilities (including water treatment);
  - $62m other cost (including reserves);
  - $60m apex (after 2037).

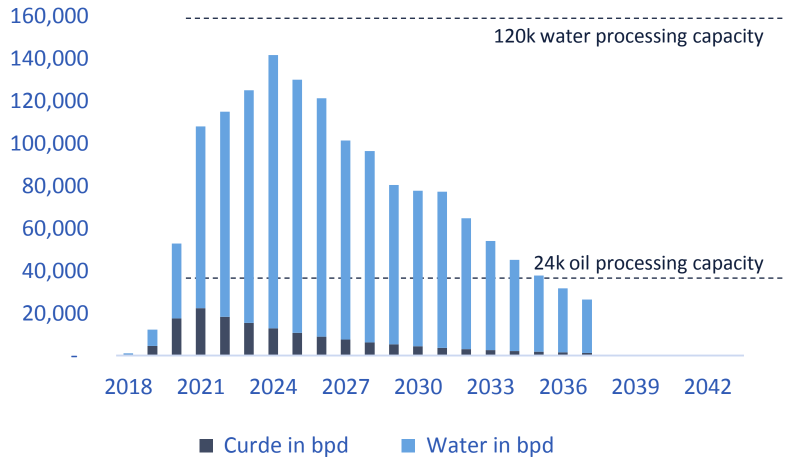
- Operating Cost: $11.3/bbl (before transport)
  - Fixed Cost: $0.675m per month;
  - Variable Lifting Cost: $5.7 per bbl;
  - Water disposal cost: $0.18 per water barrel;
  - Diluent cost: $3 per bbl;

- Other Cost:
  - Transportation (pipe & barge): $12 per bbl;
  - Royalties: 5% up to 40 MMbbl; sliding scale up to 20% at 100k pbd;
  - Tax Rate: 31.5%; Allowance Rate: 60%;
  - Tax Losses Carried Forward: $310m YE 2018;

Type Curve 1: IP 5,000



Oil – Water Production (in bpd) & Capacity



Source: BGH analysis; Company filings; Eight Capital; Note: IP = Initial Production; bpd = barrels per day

NAV Base Case

The current share price of CAD 0.43 basically puts the successful development of Bretaña in doubt and gives an informed investor significant re-rating potential.

NAV – Base Case of 55 Mmbbl from 16.7% recovery factor on 330 MMbbl of OOIP

Summary NAV: Base Case 2P Reserves for Core NAV 17/12/2019	WI in %	Reserves (Net) Gas bcf	Liquids Mbbl	Total Mboe	Unrisked NAV US$m	Chance of Success in %	Risked NAV US$m	Unrisked NAV CADm	Unrisked NAV p/share	Of total NAV in %	Risked NAV CADm	Risked NAV p/share	Of total NAV in %
Producing Assets:									diluted			diluted	
Block 95 - Brentana, Peru	100.0%	0.0	55.1	55.1	386	100.0%	386	513	0.729	31.0%	513	0.729	79.7%
Other					0	0.0%	0	0	0.000	0.0%	0	0.000	0.0%
Producing Assets		**0.0**	**55.1**	**55.1**	**386**	**100.0%**	**386**	**513**	**0.729**	**31.0%**	**513**	**0.729**	**79.7%**
Adjusted Cash (Net Debt): 30/06/2019					59		59	78	0.110	4.7%	78	0.110	12.1%
NPV TLCF					0		0	0	0.000	0.0%	0	0.000	0.0%
NPV G&A adjustments					0		0	0	0.000	0.0%	0	0.000	0.0%
Core NAV		**0.0**	**55.1**	**55.1**	**444**	**100.0%**	**444**	**591**	**0.839**	**35.7%**	**591**	**0.839**	**91.7%**
Development Assets:													
none	100.0%	0.0	0.0	0.0	0	0.0%	0	0	0.000	0.0%	0	0.000	0.0%
Risked development NAV		**0.0**	**0.0**	**0.0**	**0**	**0.0%**	**0**	**0**	**0.000**	**0.0%**	**0**	**0.000**	**0.0%**
Exploraton & Appraisal Assets:													
Block 107 - Osheki	100.0%		534.0	534.0	801	5.0%	40	1,065	1.513	64.3%	53	0.076	8.3%
Block 133	100.0%		n/a	n/a	0	0.0%	0	0	0.000	0.0%	0	0.000	0.0%
Appraisal NAV		**0.0**	**534.0**	**534.0**	**801**	**5.0%**	**40**	**1,065**	**1.513**	**64.3%**	**53**	**0.076**	**8.3%**
Total NAV		**0.0**	**589.1**	**589.1**	**1,245**	**38.9%**	**485**	**1,656**	**2.352**	**100.0%**	**644**	**0.915**	**100.0%**
Share Price	CAD/share								0.430			0.430	
Upside	**in %**								**447%**			**113%**	
Input:	Assumed:	17/12/19											
USD/CAD exchange rate	1.33	1.317											
Number of shares	704.3	704.3	million										
Price Deck: Brent	65.0	65.7	$/bbl										

Source: BGH analysis; Fully diluted share count; Note: OOIP = Original Oil in Place; MMbbl =m blue barrels

Relative Valuation

Most quality E&Ps are cheap today. PetroTal, however, trades at a 40-60% discount to its most relevant Latin American peer group, i.e. to E&Ps with similar operating netbacks, country risk or tax rates, basically suggesting the development will fail.

Selected Peer Group Comparison

Selected LatAm Peers 16/12/2019	M-Cap US$m	EV US$m	2P Res. Mmboe	Oil in %	Prod (bpd) 2020E	Netback US$/boe	RLI (years)	EV/2P 2020E	EV/flowing barrel
GEOPARK LTD	1,178	1,271	184.0	85.0%	47,150	33.0	10.7	6.9	26,957
GRAN TIERRA ENERGY INC	429	1,012	142.0	85.0%	39,830	24.8	9.8	7.1	25,411
PAREX RESOURCES INC	2,267	1,916	186.0	95.0%	62,400	40.7	8.2	10.3	30,700
FRONTERA ENERGY CORP	674	827	171.0	95.0%	63,000	23.7	7.4	4.8	13,126
AMERISUR RESOURCES PLC	309	299	25.6	100.0%	4,500	n/a	15.6	11.7	66,472
CANACOL ENERGY LTD	610	943	93.2	0.0%	39,417	15.3	6.5	10.1	23,932
Weighted Average	**5,466**	**6,268**	**801.8**		**256,297**			**7.8**	**24,457**
PETROTAL CORP	**240**	**181**	**39.8**	**100.0%**	**17,592**	**28.2**	6.2	**4.6**	**10,301**
Premium / (Discount)								**-42%**	**-58%**

Note:
Netback of Geopark, Gran Tierra & Parex by BGH; assumes $65 Brent; over life of fields; pre-tax, post discounts, transport, opex, royalty & interest
Netback of Frontera = Operating Netback according to May 2019 company presentations for Q4 2018
Netback of Canacol = Operating Netback estimate 2019 by Eight Capital research in Feb 2019; Note: Canacol is a local gas producer at $4.75 Mcf gas prices
RLI = Reserve Life Index in years of 2P reserves and at 2020E production rate

Source: BGH analysis; Bloomberg; Eight Capital; Company filings; Note: E&P = Exploration & Development Company

Reserve Upside

Our assessment from existing data, both analogue fields and well data, however suggests that the 2P reserves used in our NAV are too conservative. For a detailed discussion, click here.

Trend of Reservoir

16/12/2019	CPR	"2P Plus"	Trend	Upside
Original Oil In Place (OOIP)	330	330	379	15%
Recovery Factor (RF)	12%	17%	24%	100%
2P Reserves (in MMbbl)	**39.6**	**55.1**	**91.0**	**130%**

Source: BGH analysis

More Upside Potential

Applying a 24% recovery rate and 380 Mmbbl Original Oil in Place (OOIP), our NAV target reveals 346% upside from today's share price.

NAV – Upside Case with 24% recovery factor on 380 Mmbbl OOIP

Summary NAV: Upside Case 3P Reserves with 24% RF for Core NAV 17/12/2019	WI in %	Reserves (Net) Gas bcf	 Liquids Mbbl	 Total Mboe	Unrisked NAV US$m	Chance of Success in %	Risked NAV US$m	Unrisked NAV CADm	Unrisked NAV p/share	Of total NAV in %	Risked NAV CADm	Risked NAV p/share	Of total NAV in %
Producing Assets:									diluted			diluted	
Block 95 - Brentana, Peru	100.0%	0.0	39.8	39.8	916	100.0%	916	1,218	1.730	51.6%	1,218	1.730	90.3%
Other					0	0.0%	0	0	0.000	0.0%	0	0.000	0.0%
Producing Assets		**0.0**	**39.8**	**39.8**	**916**	**100.0%**	**916**	**1,218**	**1.730**	**51.6%**	**1,218**	**1.730**	**90.3%**
Adjusted Cash (Net Debt): 30/06/2019					59		59	78	0.110	3.3%	78	0.110	5.8%
NPV TLCF					0		0	0	0.000	0.0%	0	0.000	0.0%
NPV G&A adjustments					0		0	0	0.000	0.0%	0	0.000	0.0%
Core NAV		**0.0**	**39.8**	**39.8**	**975**	**100.0%**	**975**	**1,296**	**1.840**	**54.9%**	**1,296**	**1.840**	**96.1%**
Development Assets:													
none		0.0	0.0	0.0	0	0.0%	0	0	0.000	0.0%	0	0.000	0.0%
Risked development NAV		**0.0**	**0.0**	**0.0**	**0**	**0.0%**	**0**	**0**	**0.000**	**0.0%**	**0**	**0.000**	**0.0%**
Exploraton & Appraisal Assets:													
Block 107 - Osheki	100.0%		534.0	534.0	801	5.0%	40	1,065	1.513	45.1%	53	0.076	3.9%
Block 133	100.0%		n/a	n/a	0	0.0%	0	0	0.000	0.0%	0	0.000	0.0%
Appraisal NAV		**0.0**	**534.0**	**534.0**	**801**	**5.0%**	**40**	**1,065**	**1.513**	**45.1%**	**53**	**0.076**	**3.9%**
Total NAV		**0.0**	**573.8**	**573.8**	**1,776**	**57.1%**	**1,015**	**2,362**	**3.353**	**100.0%**	**1,349**	**1.916**	**100.0%**
Share Price	CAD/share								0.430			0.430	
Upside	**in %**								**680%**			**346%**	

Source: BGH analysis; Note: OOIP = Original Oil In Place; MMbbl = million blue barrels

Sensitivity

A sensitivity table reveals the upside potential for today's share price at different crude oil prices and recovery factors while leaving the Osheki prospect unchanged…

Sensitivity for Upside Case: Different Brent Prices & Recovery Factors (at 380 MMbbl OOIP)

346%	45.0	55.0	65.0	75.0	85.0	Brent (in US$/bbl)
12%	50.9%	184.9%	316.6%	446.2%	574.8%	
18%	61.6%	197.7%	331.1%	464.4%	596.7%	
24%	70.4%	208.6%	345.6%	482.7%	618.7%	
30%	74.6%	215.6%	355.5%	495.6%	633.8%	
36%	82.0%	226.4%	370.1%	513.1%	654.7%	
Recovery						

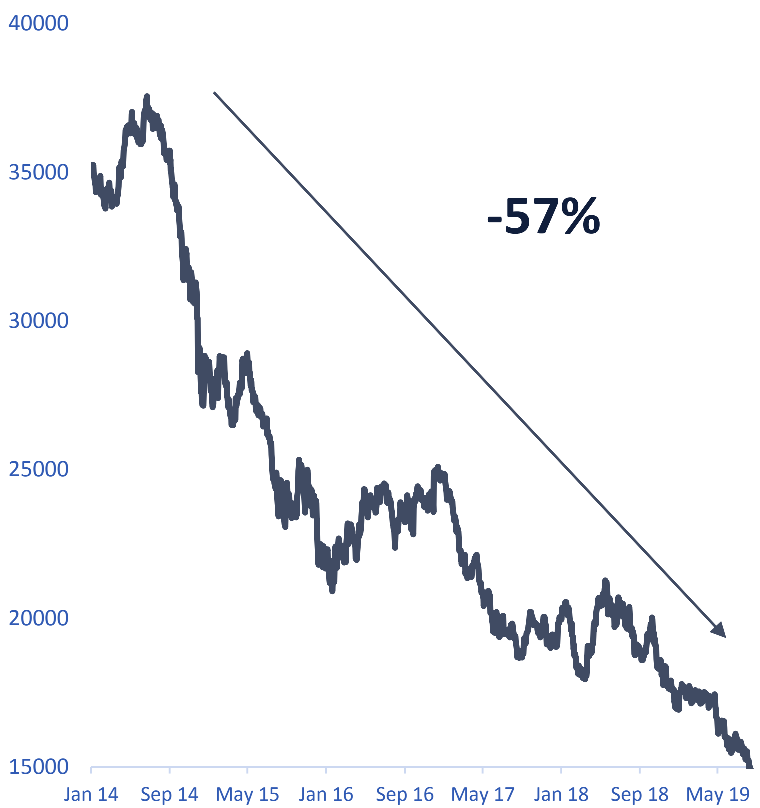
Source: BGH analysis; Note: MMbbl =m blue barrels

Why does the opportunity exist?

Broken Sector Sentiment

Sentiment for energy & energy related stocks have reached a stage of capitulation. In short, investors want to own Google - not ExxonMobil, despite a doubling of Brent prices between 2016 and today as supply as well as demand concerns dominate the headlines…

Energy Stocks / S&P 500 (Index)

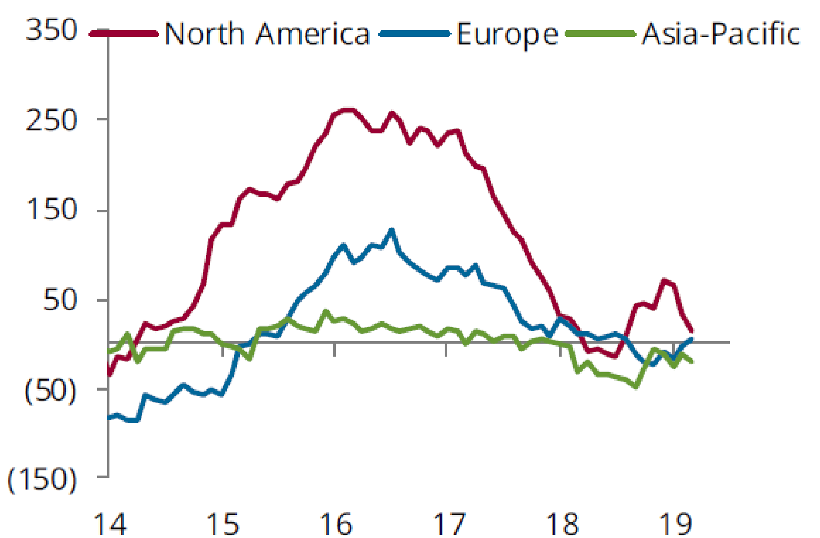


Brent Price (in US$/barrel)

Robust Physical Oil Market

…meanwhile the physical market has removed any overhang in stocks from excess supplies from the times of over-investments pre-2014. Even better, timespreads in 2019 exhibit record backwardation - a measure of a healthy physical market.

OECD Crude Stocks relative to 5-year Avg (Mb)



Timespreads: Brent July – Dec Contracts

Source: BGH analysis; Bloomberg; Energy Aspects; Note: Mb = million barrel

Term Structure of Futures Curve

Partly, oil and gas reserves are valued as a function of the Futures curve. The latter has priced-in renewed bearishness for oil markets, starting in October 2018. In our view, this allows for a well-timed investment into PetroTal's low cost asset base.

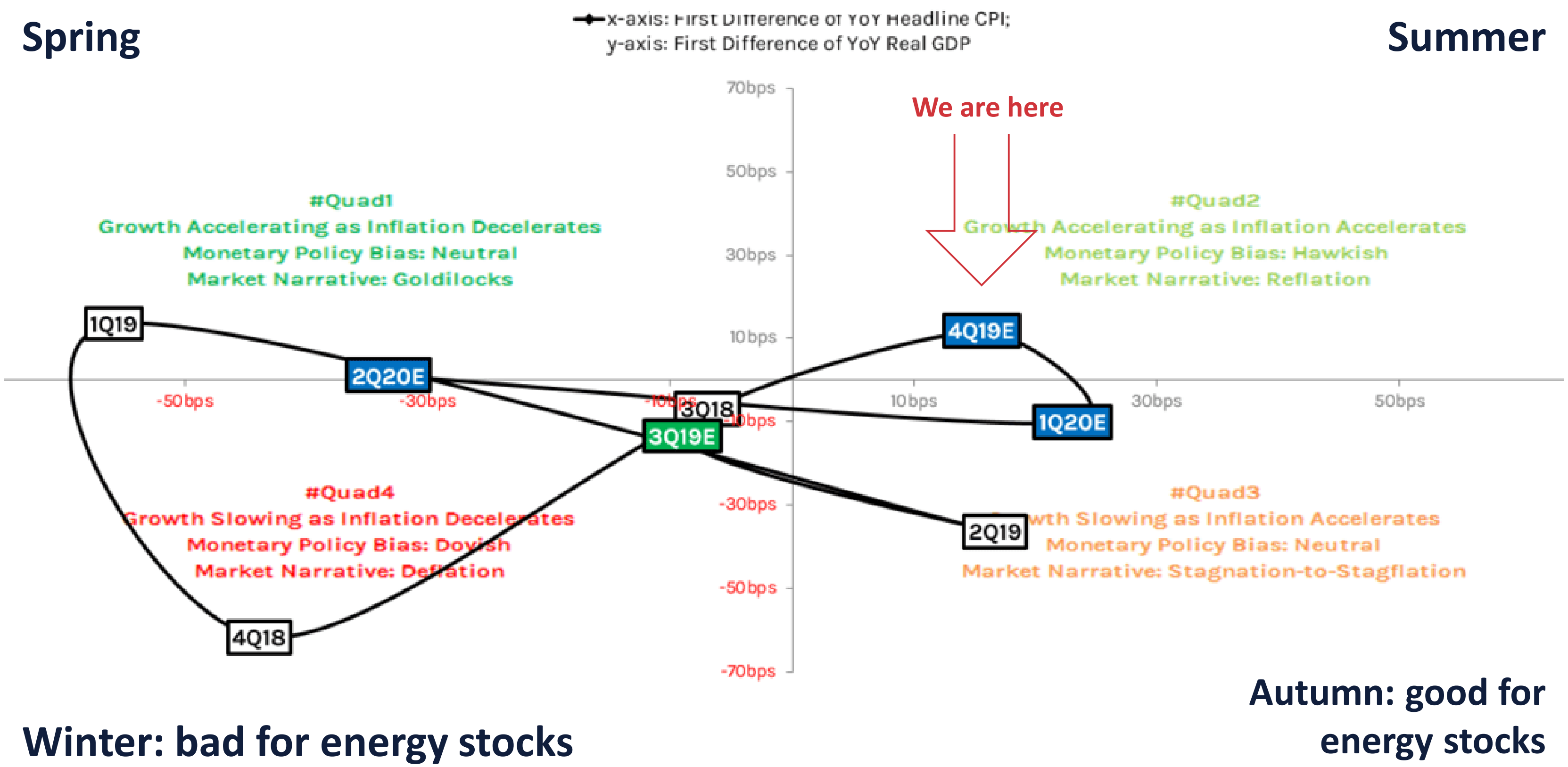
Brent Future Curves (in US$/bbl): actual in orange; 6 month ago in green; 12 months ago in blue

 Source: Bloomberg

GDP Slowdown AND Deflation

During H1 2019, the world economy deflated while GDP was slowing down. This is bad for energy stocks in modern capital allocation. However, in Q4 2019 the world economy inflates as commodity prices increased. We expect this to continue into Q1 2020 and as a weakening dollar and as past and likely future monetary stimulus supports such a trend.

Macro Seasons: Rate of Change of GDP (y axis) & Inflation (x axis), in basis points (bps)

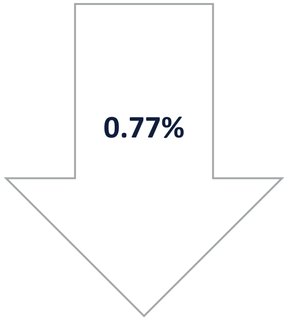


Source: BGH analysis; Hedgeye;

Central Bank Inflation

Meanwhile, markets are pricing in 3 rate cuts of 25bps each (or a combination for 77bps) by the Fed to accommodate the US economy by August 2021. Such policy typically weakens the dollar and supports higher oil prices. That should make for a good energy investment.

2 Year United States Government Bond: Yield (in %)

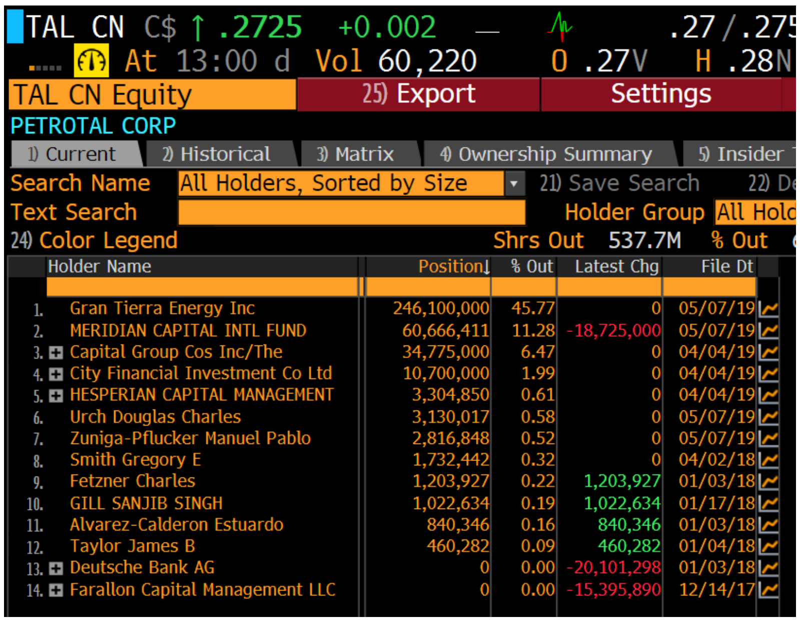


 Source: BGH analysis; Bloomberg; Note: bps = basis points = 10bps = 0.1%

Share Overhang & Lack of Liquidity

PetroTal is an incomplete spin-off by Gran Tierra which continues to hold 46% of all outstanding shares. In the past 12 months, its Canadian listed shares had a total of CAD 14m traded - not nearly enough to attract relevant institutional investors - yet. Obviously, Gran Tierra's stake also signals a share overhang which may prevent new buyers from purchasing just now.

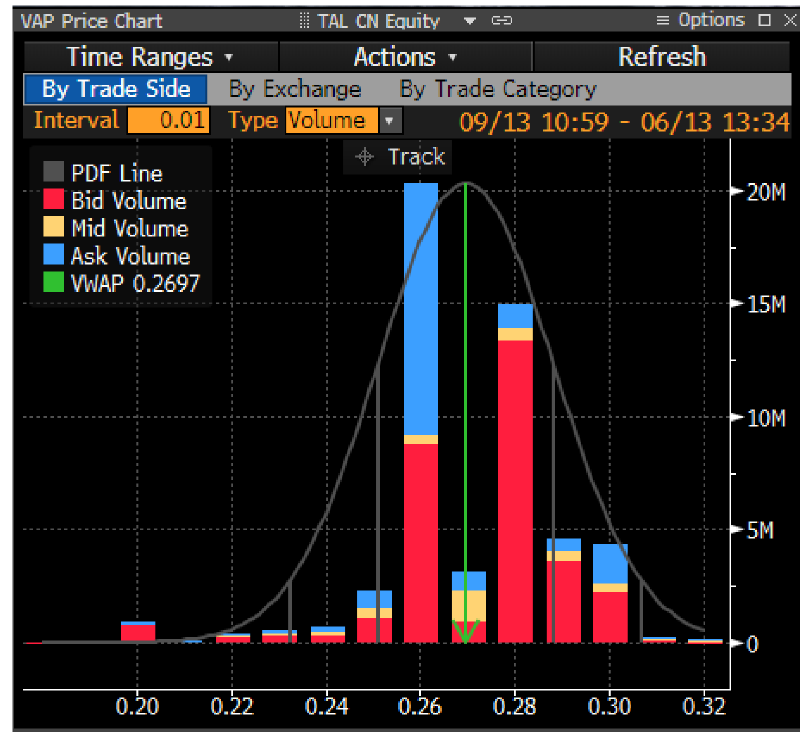
Ownership & Share Overhang



TAL CN C$ ↑ .2725 +0.002 — .27 / .275
At 13:00 d Vol 60,220 O .27V H .28N
TAL CN Equity | 25) Export | Settings
PETROTAL CORP
1) Current | 2) Historical | 3) Matrix | 4) Ownership Summary | 5) Insider
Search Name: All Holders, Sorted by Size | 21) Save Search | 22) De
Text Search | Holder Group: All Hold
24) Color Legend | Shrs Out 537.7M | % Out

	Holder Name	Position	% Out	Latest Chg	File Dt
1.	Gran Tierra Energy Inc	246,100,000	45.77	0	05/07/19
2.	MERIDIAN CAPITAL INTL FUND	60,666,411	11.28	-18,725,000	05/07/19
3.	Capital Group Cos Inc/The	34,775,000	6.47	0	04/04/19
4.	City Financial Investment Co Ltd	10,700,000	1.99	0	04/04/19
5.	HESPERIAN CAPITAL MANAGEMENT	3,304,850	0.61	0	04/04/19
6.	Urch Douglas Charles	3,130,017	0.58	0	05/07/19
7.	Zuniga-Pflucker Manuel Pablo	2,816,848	0.52	0	05/07/19
8.	Smith Gregory E	1,732,442	0.32	0	04/02/18
9.	Fetzner Charles	1,203,927	0.22	1,203,927	01/03/18
10.	GILL SANJIB SINGH	1,022,634	0.19	1,022,634	01/17/18
11.	Alvarez-Calderon Estuardo	840,346	0.16	840,346	01/03/18
12.	Taylor James B	460,282	0.09	460,282	01/04/18
13.	Deutsche Bank AG	0	0.00	-20,101,298	01/03/18
14.	Farallon Capital Management LLC	0	0.00	-15,395,890	12/14/17

Liquidity



Source: BGH analysis; Bloomberg

Charting the Spin-Off Effect

Again, PetroTal is the effective spin-off of Gran Tierra's Peruvian assets into the listed shell of Sterling Resources, a failed E&P listed in Toronto. For "Chart Technicians" out there who screen for value – and there are many – PetroTal continues to look like a failed micro cap E&P not worth buying…

Historical Share Price (in CAD / share)

9 November 2017: Sterling & PetroTal enter into an arrangement to merge in order to purchase the Peruvian subsidiary of Gran Tierra (link). The rational of the transaction was described as follows:

- Pure-play Peruvian strategic partnership between Sterling, PetroTal and GTE;
- Net cash position of USD$ 40m;
- 100% working interest in Block 95 with 39.8 Mmbbl of 2C contingent resources;
- Substantial infrastructure in place at Bretaña, with the ability to deliver first production by Q4 2018;
- Robust netbacks of USD$24/bbl forecast;
- Fully financed to commercial production at Bretaña targeting 5,000 bpd in first half of 2019;
- Significant recovery factor upside at Bretaña as analogous fields in Peru have achieved recovery factors of approximately 20% – 40% versus 12% estimated for Bretaña;

Source: BGH analysis; Company filings; Bloomberg; Note: E&P = Exploration & Production; Mmbbl = million blue barrels

Pre-Production Asset

In our view, PetroTal's development risk matters in the market. We will however explain at length why we are convinced it is unwarranted on the following pages.

Pre-Production Perception

- From a capital market perspective, PetroTal remains largely a pre-production asset, with much to prove around resources and production in 2019.
- We explain at length in this paper why the technical risks at Bretaña are low and see mostly execution risk.
- Even when modelling scenarios with increased costs and delayed growth, we still see the current valuation as overly punitive.
- Given the latest IP rates of the two horizonal wells so far, we modelled two cases: 16.7% and 24% recovery of OOIP of 330 Mmbbl and 380 Mmbbl, respectively, and both show significant share price upside.

PetroTal in May 2019

- Achieved first production in June 2018 under budget and ahead of schedule
- Currently producing >3,000 bopd from two wells
- Third oil producer spud April 21st to reach 5,000 bopd by June, already at TD
- Low cost production with >10,000 bopd by early 2020

Source: BGH analysis; Note: As at 21 June 2019, PetroTal produces over 5,000 bpd; Mmbbl = million blue barrels;

Underappreciated Cost Advantage

The investment by Gran Tierra before 2017 created the basis for Bretaña's development to be commercial on the basis of 2P reserves of 39.8 Mmbbl. Including the US$ 387m sunk cost, the asset would remain undeveloped on the basis of its commercial merits and at $65 Brent.

Netback & ROIC (in US$ and %)

Netback & ROIC: 55 MMbbl		US$/bbl	US$/bbl	US$/bbl	Comments
Brent		55.0	65.0	75.0	
Discount for oil quality	14.0%	(7.7)	(9.2)	(10.5)	API 19.5 (medium oil)
Realised Price at the well head		**47.3**	**55.8**	**64.5**	
Royalty rate	5.0%	(2.4)	(3.1)	(3.2)	on realised price
Barging & Pipeline tariff		(12.7)	(12.7)	(12.7)	transportation to East coast refinery (Talara)
Operating Cost		(11.8)	(11.8)	(11.8)	between $8-20/bbl over the life of the reservoir
Netback (pre-tax)		**20.4**	**28.2**	**36.8**	
Corporate tax rate	32.0%	(8.0)	(11.8)	(13.3)	incl. US$ 310m tax losses & US$300m investment allowance
Netback		**12.4**	**16.3**	**23.5**	
Investment / barrel		(8.5)	(8.5)	(8.5)	$333 million investment (point forward 2018), excl. Apex
Netback (all-in)		**3.9**	**7.9**	**15.1**	
ROIC excluding Sunk Cost		**47%**	**93%**	**178%**	
Investment & Sunk Cost / barrel		(18.2)	(18.2)	(18.2)	including $387 million sunk cost by Gran Tierra bw 2009-2017
Netback (all-in, incl. Sunk Cost)		**(4.3)**	**(0.3)**	**6.8**	
ROIC incl. Sunk Cost		**-24%**	**-2%**	**38%**	

Source: BGH analysis; company filings; Note: MMbbl =m blue barrels

Overlooked Entrepreneurial Approach

We doubt the market pays enough attention to the culture change at PetroTal (versus Gran Tierra's previous culture) since Manolo's entrepreneurial approach took over. But for the new shareholders, it will make all the difference!

Capital Program: Budget versus Actual August 2018

ACTIVITY	Progress To Date (%)	Budget (US$)	Expected (US$)
Engineering	100%	500,000	462,200
Base Camp Maintenance and Related Construction	100%	1,500,000	1,067,300
Logistics, IT Support	Ongoing	2,200,000	2,115,900
Oil Production Facilities [1, 2]	100%	5,500,000	4,643,000
Platform Maintenance and Expansion	95%	2,100,000	2,019,800
Produced Water Treatment and Reinjection Facilities [1]	55%	6,000,000	4,797,200
Bretaña Production Facilities ➔		**$ 17,800,000**	**$ 13,294,500**
Well Interventions: Oil Producer and Water Injector	100%	2,000,000	305,000
HSE, CSR, Insurance	Ongoing	2,050,000	1,482,300
Contracted Personnel, Capitalized G&A	Ongoing	2,650,000	1,437,900
OVERALL Bretaña Project ➔		**$ 24,500,000**	**$ 18,330,600**

Source: Company filings

Bretaña in Depth

Country & Country Risk

Geography, Demography & Basics

Peru is the third largest country in Latin America, with a population of 32 million, freedom of religion and ample natural resources.

Geography & Demography

Population	‣ 32.5 million people ‣ 76.7% resides in urban areas
Age structure	‣ 0 - 14 years 26.7% (2018) ‣ 15 - 64 years 66.2% (2018) ‣ 65 years and over 7.1% (2018)
Annual growth rate	‣ 1.1% (2015 - 2018)
Birth rate	‣ 17.7 births/1,000 population (2018)
Death rate	‣ 5.7 deaths/1,000 population (2018)
Sex ratio	‣ At birth 1.03 male/female
Life expectancy at birth	‣ 75.2 years (2018)

Basics

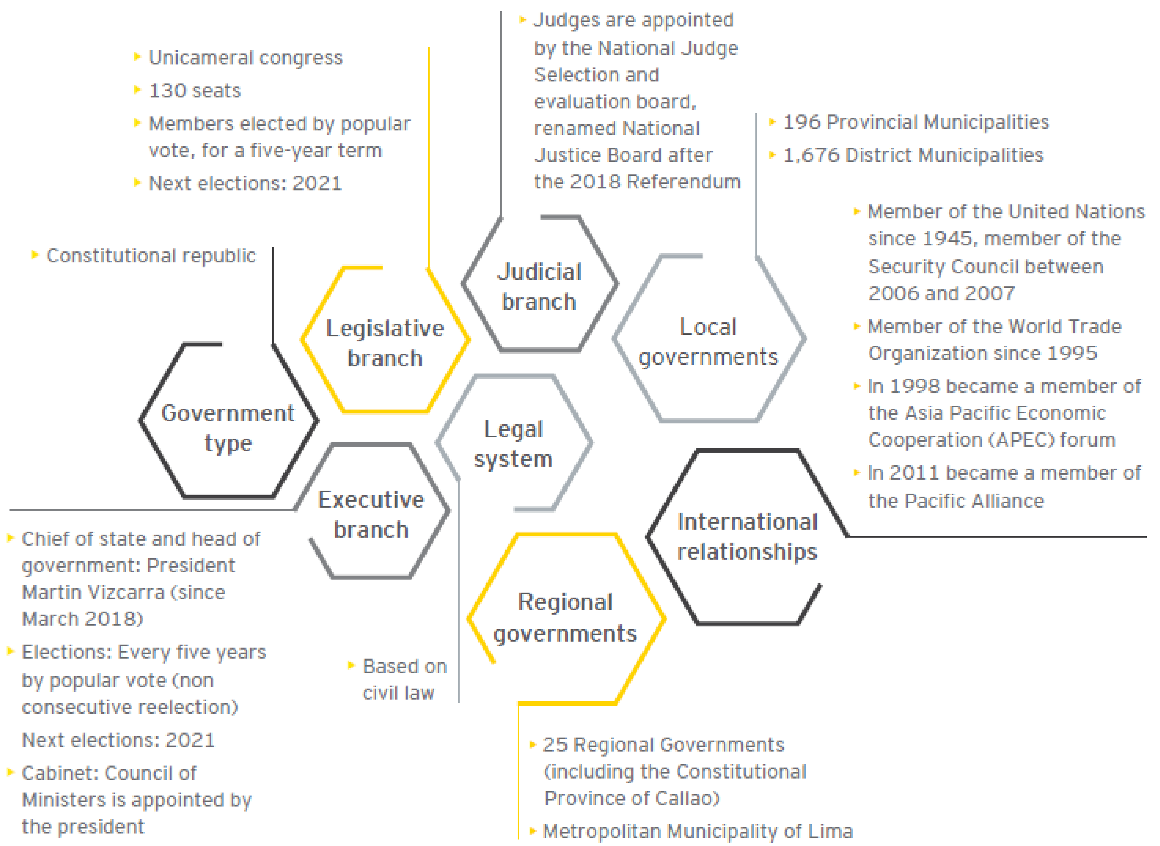
- Population: 32.5 million (76.7% urban);
- Religion: Freedom of religion; mostly Roman Catholic;
- Languages: Spanish; Quechua; Aymara
- Currency: Sol (PEN) – 1 US$ = 3.369 PEN
  Free floating 10y range to US$: 2.53 – 3.52
- Climate: Varies from tropical in Amazon region to dry on the Coast; cold in Highlands;
- Natural Resources: Gold, copper, silver, zinc, lead, hydrocarbons, fish, phosphates and agricultural products;
- Time zone: GMT -5 (five hours behind Greenwich Mean Time)

Source: Google Maps; Bloomberg; Ernst & Young 2019

Form of Government

Under the constitution of 1993, Peru is a stable democratic constitutional republic with a multiparty system. The president is the Head of State & elected every 5 years.

Country Overview – stability since 1990ies

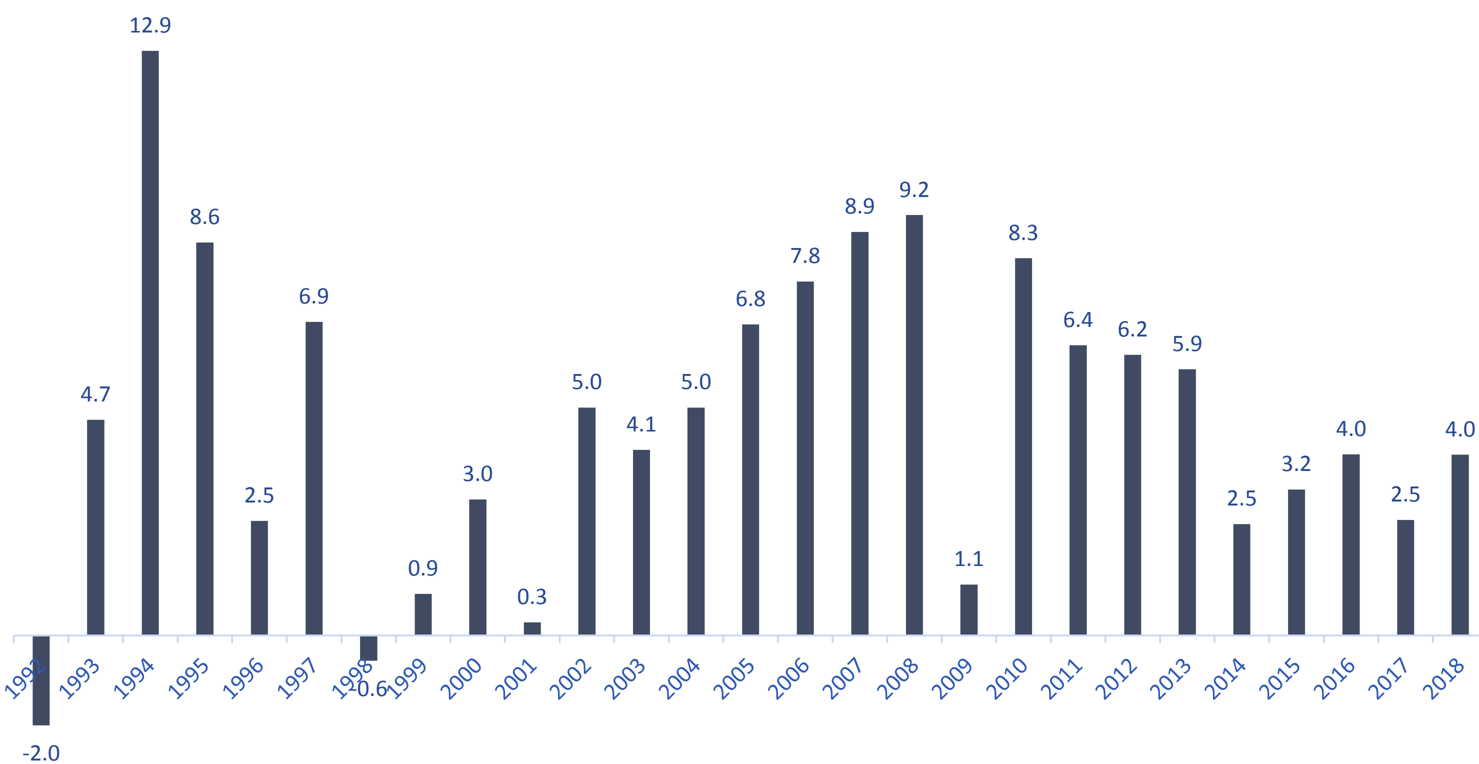


Source: Ernst & Young, 2019

GDP Development

Peru has been one of the most successful economies in Latin America for the past 25 years, with an average growth rate of 4.7% since 1992 from mostly pro-business governments. Over the past decade, GDP grew by 5.9%. The IMF projects for 4% growth for next two years.

Real GDP Growth (in %): average of 4.7% since 1992

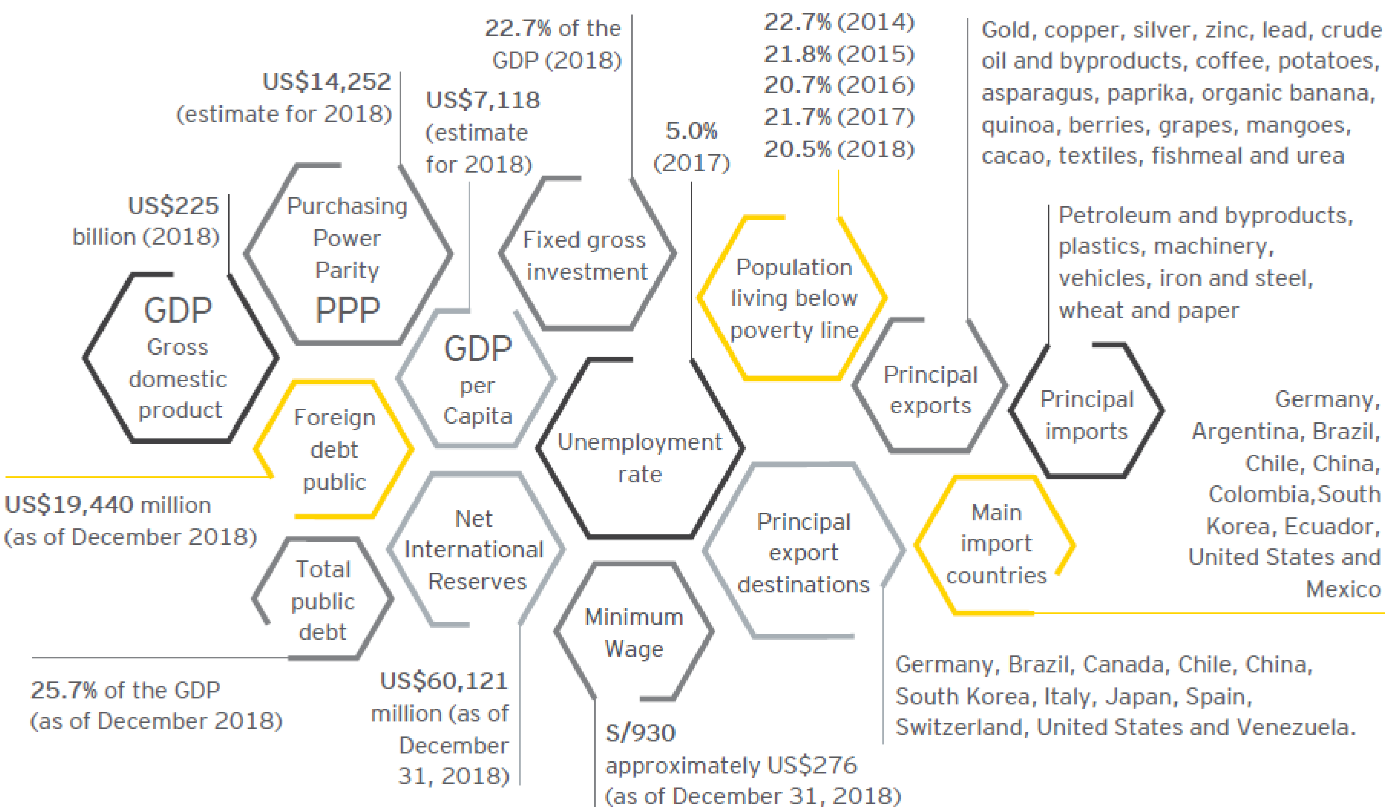


 Source: Bloomberg

Economic Overview

Economic growth is the result, among others, of prudent monetary & fiscal policies applied over the past 2 decades, reducing debt from 29.9% in 2007 to 25.7% of GDP in 2018.

Economic Overview



 Source: Ernst & Young 2019

Economic Activities

In 2018, Peru ranked as the world's top producer of fishmeal ($1.5bn exported) & 3rd largest exporter of avocado ($0.8bn). It is also the 2nd largest exporter of silver, copper & zinc.

Main Economic Activities

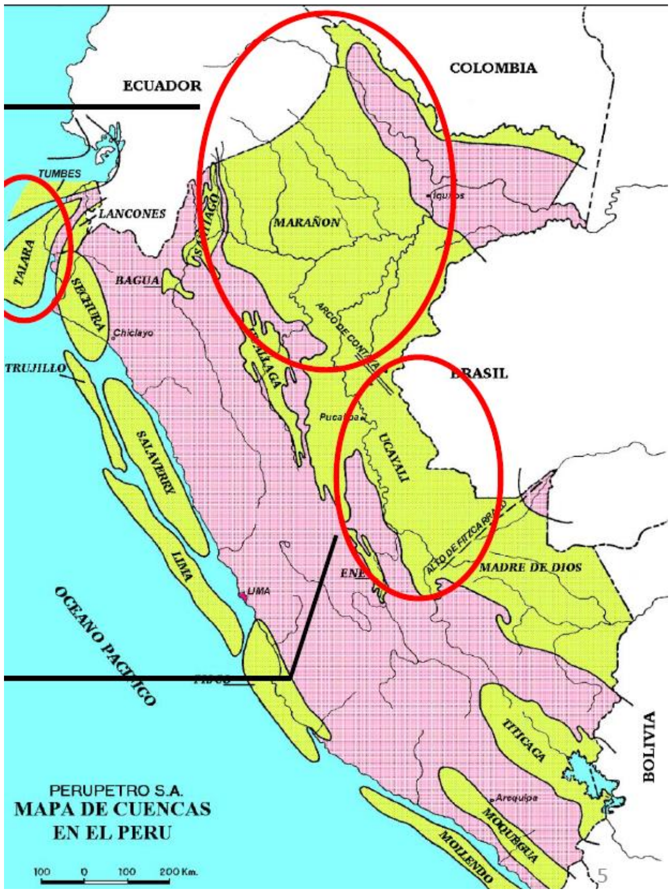
- Fishery
- Petroleum
- Oil refinery
- Sugar refinery
- Fishmeal plant
- Natural gas
- Au Gold
- Ag Silver
- Cu Copper
- Textile industry
- Cement plant
- Chemical plant
- Metal industry
- Smeldering
- Metallurgical industry
- Zn Zinc
- Pb Lead
- Fe Iron

 Source: Ernst & Young 2019

Oil & Gas History

Peru is a minnow oil producer with 0.13 Mmboepd, often referred to as «under explored». For context, its neighbour Colombia produces 0.9 Mmboepd.

Peru Oil & Gas Basins



Drilling History in Peru

BASIN	WILDCATS	%
Talara	1,299	84.68
Marañón	115	7.50
Ucayali	59	3.85
Sechura	24	1.56
Tumbes - Progreso	13	0.85
Santiago	7	0.46
Madre de Dios	6	0.39
Trujillo	4	0.26
Titicaca	4	0.07
Pisco	1	0.07
Huallaga	1	0.00
Lima	1	0.00
Mollendo	0	0.00
Salaverry	0	0.00
Moquegua	0	0.00
Bagua	0	0.00
Ene	0	0.00
	1,534	100.00

Source: Perupetro; Note: Mmboepd = million barrels of oil equivalent per day

Liquids Production

Over the last 10 years, Peru produced about 140,000 barrels per day.

Peruvian Liquids Production (in '000 bpd)

Analysis	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Block 192	23	16	19	18	15	15	13	10	1	4
Block 31-C (Aguaytia)	3	3	3	2	3	2	2	2	1	1
Block 56	10	34	33	35	37	38	38	32	29	26
Block 57	-	-	-	-	-	-	4	5	9	10
Block 67	-	-	-	-	-	0	5	2	0	-
Block 8	15	14	12	10	10	10	10	8	4	6
Block 88	31	37	47	45	46	63	58	52	50	49
Block III	2	4	3	3	2	2	2	1	1	1
Block X	14	13	13	13	14	12	10	11	11	11
Block XIII	2	3	4	4	3	5	6	4	4	3
Block Z-1	2	3	4	4	3	3	5	4	3	2
Block Z-2B	14	12	13	12	13	12	12	11	9	9
Minor Fields	7	7	7	6	7	7	8	10	8	9
Total Liquids ('000 b/d)	**123**	**146**	**158**	**152**	**153**	**169**	**173**	**152**	**130**	**131**

Source: WoodMac; Note: bpd = barrels per day; Note: First oil was discovered under the leadership **Dr. Fernando Zuniga y Rivero**, the father of Manolo Zuniga-Pflücker, In 1972.

Oil & Gas Country Context

Peru provides for an established oil & gas infrastructure, with significant local refining capacity and a pipeline network from 50 years of oil production.

Oil & Gas Industry

Peru has an established oil & gas industry…

- Property Rights: Standardised contracts signed into law by supreme decree; Oil Blocks usually awarded for 20 years +;
- Oil Fiscal Regime: 5-20% royalty based on volume; 32% corporate tax rate; capital allowances over 4-5 years;
- Oil Production & Consumption: 127,000 boepd versus 259,000 boepd (2017);
- Oil Infrastructure: Significant transportation and pipeline capacity covering large parts of the country, including the Amazonian;
- Oil Operators: State operator Pluspetrol; CNPC; Repsol; Hunt; Ecopetrol; etc.
- Oil Field Services: Baker Hughes; Parker Drilling; Halliburton; Schlumberger; Saipem
- Refining: 6 refiners with a total capacity of 253,000 bpd; throughput runs of 185,000 in 2015; Largest refinery is La Pampilla with a capacity of 102,000 bpd; Picture: Talara Refinery to which Bretaña will deliver oil, among others.

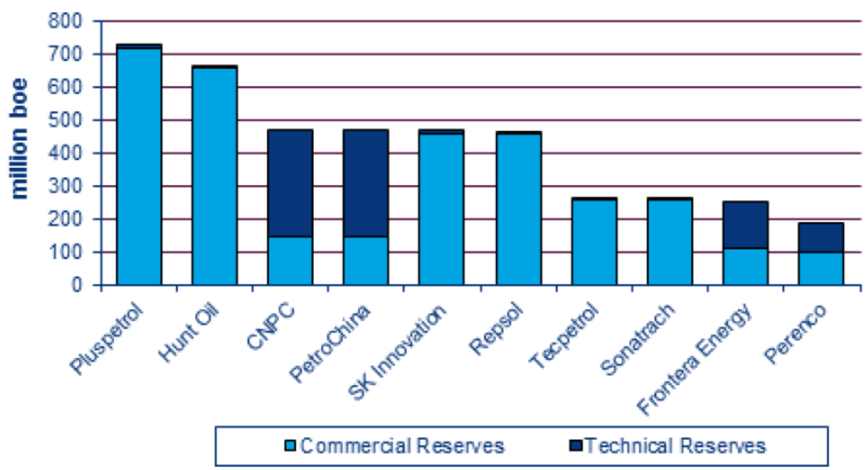
Talara Refinery

~$3B expansion & upgrade, expected completion 2020

Main Players

We met with the presidents of both state-owned oil & gas companies as part of our due diligence in October 2018 and had an excellent impression.

Remaining Commercial and Technical Reserves



The Role of Petroperú & Perúpetro

- Starting in 1969, Petróleos del Perú S.A. (Petroperú) is one of two Peruvian state-owned petroleum company.
- Its activities are mainly mid- and upstream related, i.e. transport, refining and commercialization of fuel and oil derivatives. Recently, it participated however in minority upstream stakes.
- As the de-facto monopolist, Petroperú matters to PetroTal for arm's length transportation tariffs.
- We visited the former President of Petroperú, Mr. James Atkins Lerggios, in October 2018 as part of our due diligence to better understand the future relationship with PetroTal.
- After some direct questions and 2 hours, our impression was that PetroTal will be able to beat its guidance of transportation tariffs of $9/bbl once it has fully ramped-up production.
- Sadly, Mr Lerggios has since past away.

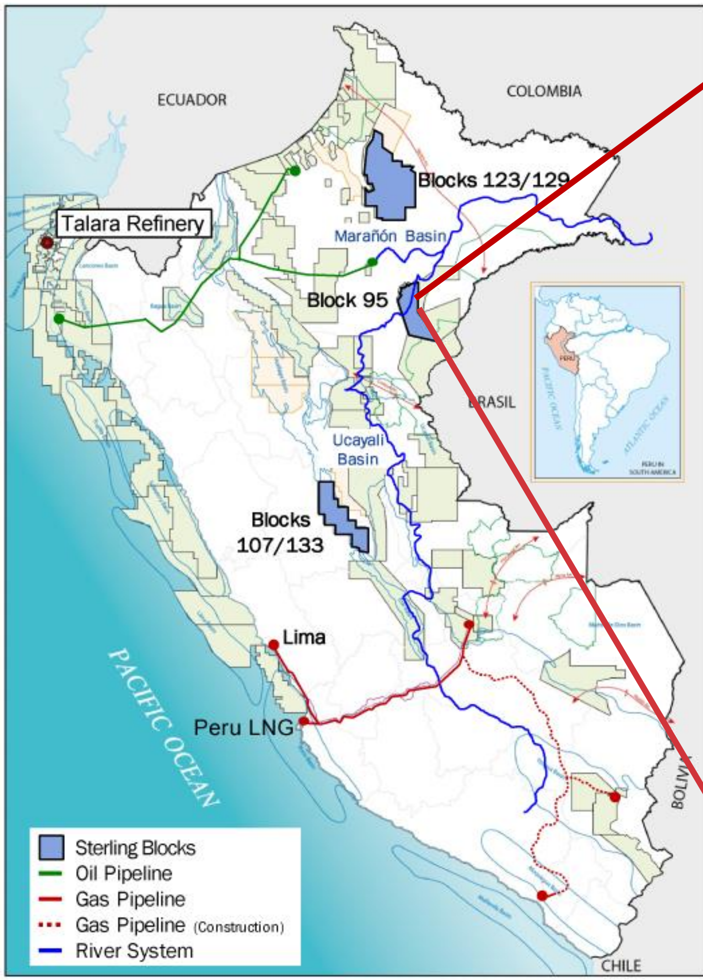
- The second state-owned player is Perupetro S.A. It is responsible for promoting, negotiating, underwriting and monitoring contracts for exploration and exploitation of hydrocarbons in Peru.
- Perupetro does not have direct interaction with PetroTal. We nevertheless met with Seferino Yesquen Leon, its President, to get a better understanding of the local oil & gas industry.

Source: WoodMac, January 2018; https://www.Petroperú.com.pe/english/about-us/history/

Location
& Permits

Block 95 – The Bretaña Field

The Bretaña field is part of Block 95 which is located within the Peruvian Amazonian and accessed by the Ucayali river.

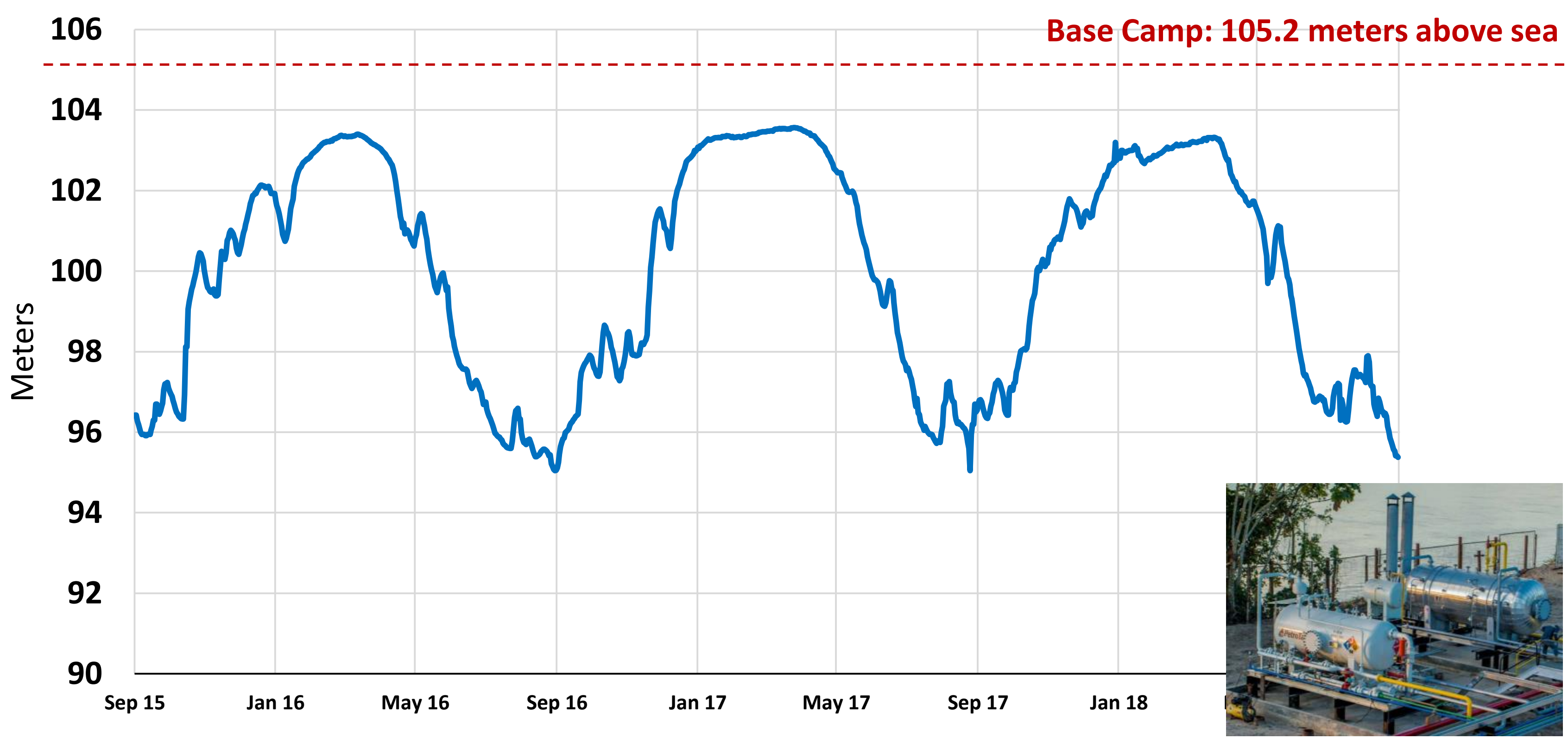


Source: CPR 2018 by Netherland, Sewell & Associates, Inc.

River Ebb & Flood

Bretaña's base camp is at 105 meter above sea which will prevent operations from stalling due to flooding as seasonal rains increase the river level by many meters each year.

Seasonality: Volatility of Puinahua River Levels (in meters)



Source: PetroTal for BGH

Bretaña Village

Block 95 is remote and sparsely populated. The Bretaña village has about 2,000 indigenous inhabitants.

- Bretaña Village: Block 95 is remote and sparsely populated. The Bretaña village has about 2,000 indigenous inhabitants.
- Indigenous Population: Of a total 28.2m population, 4m are indigenous people in Peru (some 55 groups speaking 47 languages).
- Conflicts: The overlap with communal territories, the lack of territorial cohesion and, at times in the past, the absence of effective prior consultation caused territorial and socio-environmental conflicts in Peru.
- Oil Spills: Block 95 is located in the North West of Peru, in a region without a history of oil contamination.
- Cause of Spills: Most reported oil spills in Peru were caused by Petroperú's pipeline system, NOT by oil production companies such as PetroTal.
- Relationship: Sustainable operation will depend on managing the positive relationship with the local community. We discuss this here and here.

Source: BGH analysis; Google Map

Commitment to Sustainable Operations

Bretaña is in the middle of the Amazonian. A smooth operation requires «giving back» which is why PetroTal has 5 FTE and annual budget of US$ 900,000 to work with the indigenous communities nearby and address some of their local needs.

Commitment to Sustanable Operation

- 5 full time CSR employees
- CSR team with ~75 years of combined experience
- Annual budget of ~$900K
- CSR is part of the Key Performance Indicators of all employees and management
- Commitment at Board level. HSE & CSR Committee approves the guidelines, and the Board is provided monthly updates

CSR Team Engaged with Local Communities

- In Block 95 at Bretaña with 2,000 inhabitants, as well as the 18 communities of the Puinahua District
- In Block 107 with the indigenous Ashaninka and Yanesha ethnic groups, as well as foreign settlers

Rebuilding Identity of Indigenous Communities

- Promoting processes to rebuild their identity
- Strengthening indigenous organizations
- Working with a network of NGOs, producers, and local and central government organizations

Investments in Sensitive Areas

- Pacaya-Samiria National Reserve
- San Matías–San Carlos Forest Reserve
- Oxampampa-Ashaninka-Yanesha Biosphere Reserve

Our Strategy

- Sustainability of the projects based on strategic relationships with the local population and NGOs
- Being active members of the committees that manage the reserved or protected areas
- Having a team with experience working in sensitive areas while caring for the environment
- To be recognized as a conscious user of the land that is committed to and respected for contributing to local development.

Source: Company Filings; Note: FTE = Full Time Employees

Permits

PetroTal has been given all relevant permits – a big achievement in Peru. Starting 2019, can develop out its asset.

Permits

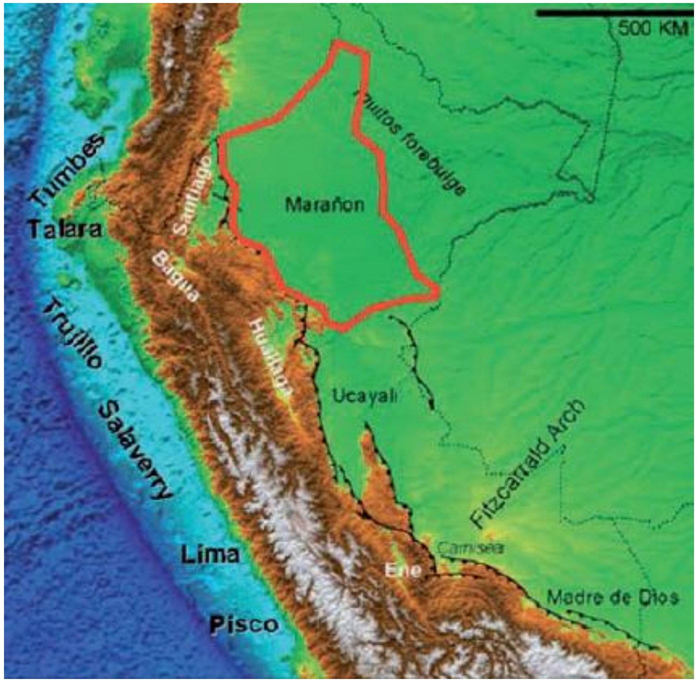
Block 95 - Bretaña	Status
Multilateral Well inside reservoir	Obtained
ITS Two Laterals inside reservoir	Obtained
Exploration Environmental Permit	Obtained
Full Field Development Environmental Permit	Obtained (May 2019)

Source: Company filings

Geology

Marañon Basin

The Oriente-Marañon basin – or Marañon basin - is Peru’s second most important source of oil production. Its first field was discovered in 1971.



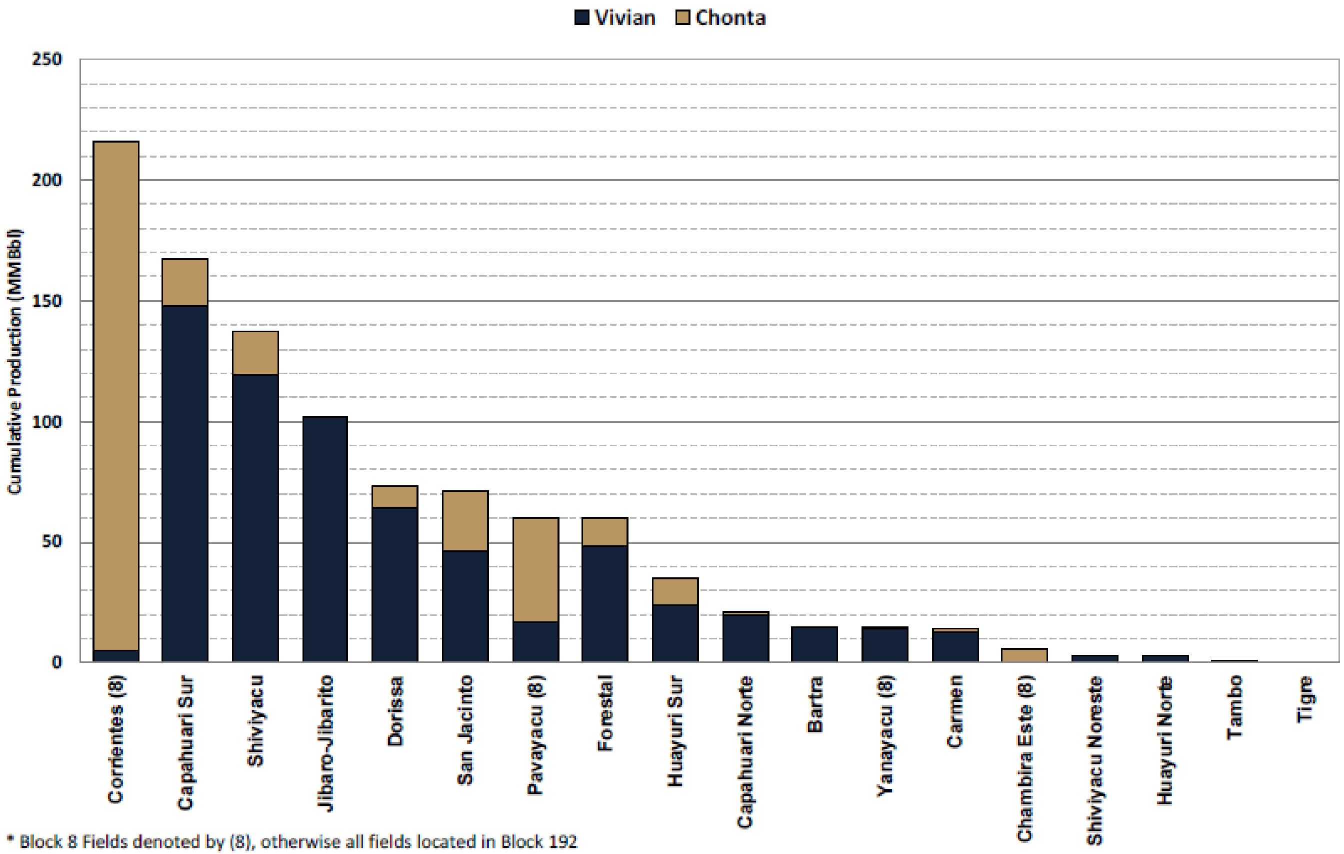
- A Basin is a depression in the crust of the Earth, caused by plate tectonic activity and subsidence, in which sediments accumulate. If rich hydrocarbon source rocks occur in combination with appropriate depth and duration of burial, then a petroleum system can develop within the basin.
- The Marañon Basin is the southern extension of a much larger Sub-Andean Foreland Basin that extends northward into Ecuador (where it is called the Oriente Basin) and Colombia (where it is called the Putumayo Basin).
- Texaco first drilled in Peru's Marañon Basin in the mid to late 1950's, but the first wells came up dry. The basin remained largely unexplored until the early 1970's when a series of oil discoveries in the Oriente, made between 1967 and 1970, resulted in new activity.
- Petroperú was awarded acreage in Marañon Basin in 1971 and the first discovery was made on Block 8 in the Corrientes Field in 1971.
- Later in 1971, **under the leadership of Dr. Fernando Zuniga y Rivero**, the father of Manolo Zuniga-Plflücker, Occidental Petroleum (Oxy) was awarded Block 1A and Union Oil (Union) was awarded Block 1B (now collectively known as Block 192).
- In 1972, Oxy reported its first discovery at the Capahuari Field and Union announced the discovery of the Jibaro Field.
- Between 1971 and 1979, 14 new fields were discovered in Block 192 and four fields were discovered in Block 8 between 1971 and 1989.

 Source: BGH analysis; Eight Capital; Geologica Acta December 2014

Production History

The two main blocks of the Vivian & Chonta Formation in the Marañon basin have produced 1 billion barrels of crude oil over 40 years – which is a lot...!

Cumulative Production of Block 192 & 8 by Field (until 2013, MMbbl)



* Block 8 Fields denoted by (8), otherwise all fields located in Block 192

Geology

Block 95 (Bretaña) is part of the Vivian Formation within the is Marañon basin. Technically, the Vivian Formation produces excellent petroleum systems with good exploration success.

Petroleum System of Marañon Basin

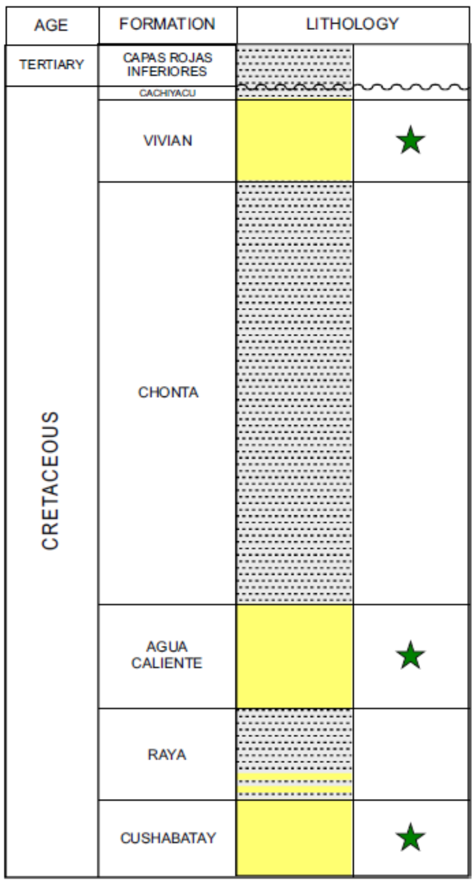
- **Source & Migration:** Oils in the northern Marañon (Block 192) are sourced from the Upper Cretaceous Chonta Formation, whereas oils in the southern Marañon (Block 8 and Block 95) are sourced from the Jurassic-Triassic Pucara Formation. During the Tertiary Period, oil migrated from the deep basin centre into the east and accumulated in subtle structural traps.
- **Reservoir:** Essentially all the producible oil occurs in the Cretaceous Vivian Formation (63%) and the Chonta Formation (35%). The Basal Tertiary and Cushabatay formations contain minor volumes of producible oil.
- **Seal:** In the Chonta Formation, interbedded sands and shales form the reservoirs and traps. The Vivian Formation is overlain by Cretaceous and Tertiary shales which form an effective seal.
- Note that the Seal of a reservoir is the biggest single risk of any oil & gas reservoir and that this risk is off the table as we know from past drilling campaigns and the current production that the oil is in place. Also see slide here (link).
- **Trap:** Historic exploration focused on identifying and drilling simple four-way dip NW-SE elongated closures. Structural closures are coincident throughout the Cretaceous as the basin deformation that formed the traps was pre-Cretaceous. Mapping suggests that this model fits for many of the fields, but there is at least some stratigraphic trapping component in some of the fields.
- **Reservoir Drive:** The Vivian and Chonta reservoirs are underlain by active aquifers that provide a natural water drive. The water drive has resulted in recovery factors averaging 29% up until 2013 for the 15 Vivian fields in Blocks 129 and 8.
- This is important as we will explain later that water is “our friend” for recovery.

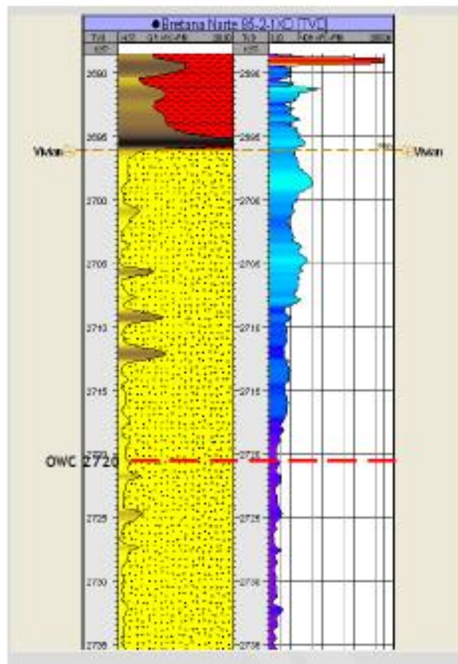
Source: BGH analysis; Eight Capital

Stratigraphy

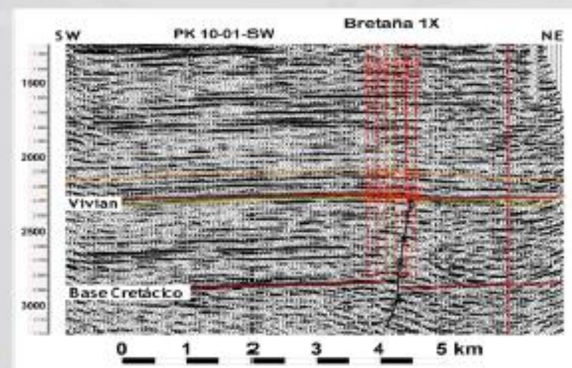
The Vivian Formation contains quarz sandstone. Early work by Gran Tierra suggests Bretaña is expected to have 24% porosity, API 18.5 degree and a net pay of 16 meters.

Bretaña Stratigraphy, Well Log & Reservoir Data





Gross Thickness:	143.5 m
Cores:	36m
Net Pay :	16 m
Porosity Avg:	24 %
Permeability Avg:	3169 mD
API:	18.5º
Production Test:	1,980 bopd
Total Sulphur Content:	< 0.5%



Source: CPR 2018; Perupetro

Reservoir

Vivian reservoirs are excellent. Porosity ranges from 14-22% and permeabilities range from 0.5 – 4.0 Darcies for most fields.

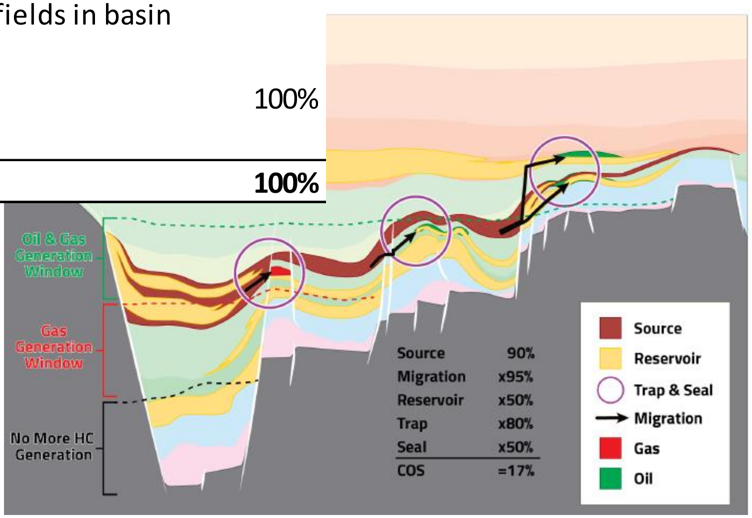
- The Vivian Formation is the most important reservoir in the basin. In Block 192, it is 60 meters thick and consists of quartz sandstones deposited in a coastal plain environment.
- The formation thickens to the south: in Block 95 the formation is 130 meters thick and was deposited in a braided stream alluvial plain environment.
- Regardless of the depositional environment, the reservoir is excellent. Reservoir porosity ranges from 14-22% and permeabilities ranging from 0.5 - 4.0 Darcies are reported for most fields.
- In Block 192, the Vivian Formation consists of two oil-charged fluvial sands separated by a low permeability shale deposit (next page - Shiviyacu 16V well log).
- The majority of the oil is produced from the lower "A" sand in Block 192. In Block 95, there is only one massive undifferentiated Vivian Sand (next page - Bretaña Norte 95-2-1XD well log).
- The tighter streaks in both logs are noteworthy because they can act as vertical flow barriers that help to prevent excessive production from the bottom water aquifer (flow is more lateral than vertical).
- Water washing and biodegradation of oil near the oil water contact has also been noted in some of the Block 192 fields. Degradation of oil quality at the oil/water contact can also act as a vertical flow barrier.
- Net pay in the Block 192 fields averages 9 meters, similar to Bretaña where net pay is expected to average ~10 meters (about 32 feet) across the structure. Log porosity in Bretaña (23% average) is slightly better than that in the Block 192 fields.
- For a general context on porosity and permeability, please see this section of the presentation.

Source: Eight Capital

Chance of Technical Success

From a geological perspective, there is <u>zero</u> exploration risk in Bretana.

	Chance of Technical Success		
1	Source	Jurassic-Triassic Pucara Formation	100%
2	Migration	during Tertiary Period: > 150km	100%
3	Reservoir	Quarz Sandstone; Vivian Formation of Maranon Basin; Massive & continuous reservoir: 100 foot gross oil column 5 wells define structure; 5,000 bpd production from 3 wells	100%
4	Trap	Unfaulted, low amplitude 4-way closing anticline; Filled to structural spill point; no gas cap Active aquifer that provides natural water drive; Consistent oil-water contact across structure; Similar trapping style to majority of producing fields in basin	100%
5	Seal	Tertiary shales	100%
	Chance of Success: 1 x 2 x 3 x 4 x 5		**100%**



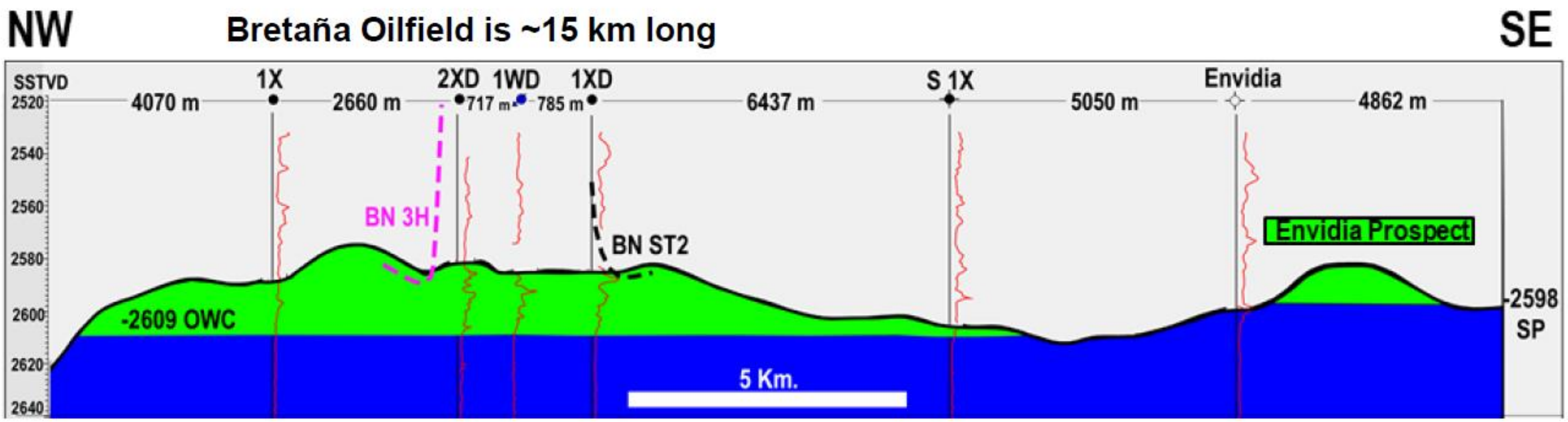
Source: BGH analysis; RS Energy

Volumetric
& Reserves

Field Structure

The main Bretaña field structure is well defined from 5 wells and as outlined on the left side of the schematic and is assumed to have 330 Mmbbl oil in place.

Bretaña Field: Well Defined Field Structural Cross Section



OOIP	NSAI (1)
1P	199 MMBO
2P	329 MMBO
3P	500 MMBO

2C: 5.6 MMBO

Source: CPR; PetroTal for BGH; OOIP = Original Oil in Place; Mmbbl = million blue barrels

Bretaña History

Amoco discovered Bretaña in 1974. Starting in 2010, Gran Tierra invested substantial amounts to de-risk the field.

- Amoco drilled the Bretaña-10-16-1X well in 1974. The well encountered a Vivian sandstone reservoir that flowed naturally at 807 Bbl/d of oil over a short duration drill stem test (with reports indicating 13° - 18° API oil). Historic data indicates that reservoir porosity averaged 22% and recoverable oil was estimated at 23 MMBbl based on a 25% recovery factor. The discovery was subsequently relinquished due to its remote location and concerns about commerciality.
- Harken Energy Corporation (through its wholly owned subsidiary, Global Energy Developments) signed a contract in 2005 that gave it a 100% interest in Block 95 containing the Bretaña discovery. The company booked 21 MMBbl of 2P reserves at Bretaña (65 MMBbl 3P), conducted background environmental and licensing activities, but did not drill a follow-up to the original discovery well.
- In late 2010, Global Energy Developments entered into a farm-out agreement with Gran Tierra in which Gran Tierra would become operator of Block 95 and retain a 60% interest in the block upon paying 100% of the gross cost of an exploration well (up to a maximum of $15MM). On January 17, 2012, Perupetro signed the assignment documents for Block 95, officially transferring 60% of the block and operatorship to Gran Tierra. On June 11, 2012, Gran Tierra acquired the remaining 40% interest in Block 95 for a cash consideration of $5.4MM.
- On February 12, 2013, Gran Tierra announced that it discovered oil in the Bretaña Norte 95-2-1XD exploration well. Log interpretations and MDT fluid and pressure sampling indicated the presence of an oil-bearing sandstone reservoir in the Vivian Sandstone beginning at 9,408 ft measured depth (MD) or 8,851 ft true vertical depth (TVD) with an approximate gross oil column thickness of 99 feet and 53 feet net pay thickness. Cores were collected over most of the reservoir interval.
- A drill stem test was conducted in the well in which “approximately 1,170 Bbl/d of 18.5° API gravity oil was produced on natural flow without pumps for 19.65 hours with 0% water cut through a 46/64-inch choke. The choke size was then increased to a 64/64 inch and oil flow increased to approximately 1,984 Bbl/d on natural flow without pumps over a period of 1.5 hours with 0% water cut. The wellhead flowing pressure and temperature were increasing through the test, indicating that the formation was cleaning up and oil flow was increasing over the duration of the test. The test was successfully concluded when all available crude oil storage capacity had been filled.”

Source: Eight Capital

Bretaña History

After the oil price collapse in 2014/2015, the CEO of Gran Tierra was terminated and the new team decided to focus on Colombia. Bretaña was spun-off in 2017.

- A horizontal sidetrack to the Bretaña Norte-95-2-1-XD (the Bretaña Norte-95-2-1-XD-ST2), which extends 486 meters to the southeast along the top of the Vivian reservoir, was drilled to conduct further testing.
- On May 28, 2013, Gran Tierra completed initial testing of the Vivian sandstone reservoir in Bretaña Norte-95-2-1-XD-ST2. A total of 1,283 ft of net pay was encountered in the well with an average porosity of 22.8%. The well tested at a final rate of ~1,699 Bbl/d on natural flow with 0% water cut, through a 32/64-inch choke, and 3,095 Bbl/d on natural flow with 0% water cut through a 64/64-inch choke. Wellhead flowing pressure was increasing during the first test, indicating the formation was cleaning up. Cumulative production for both testing periods was 3,552 Bbl and testing was concluded when all available storage capacity had been used up.
- In late 2013, Gran Tierra acquired 382 km of 2-D seismic program to provide a more detailed map of the Bretaña structure. The seismic program identified a structural extension of the Bretaña Field which has a previously drilled well (Envidia-10-24-4X) located on its flank. The Envidia-1 well had oil shows above an oil-water contact.
- At year-end 2013, GLJ assigned 61.5 MMBbl of working interest Probable Undeveloped reserves and another 52.3 MMBbl of working interest Possible Undeveloped reserves to Bretaña (61.5 MMBbl 2P and 113.9 MMBbl 3P). The cost to develop the 2P reserves was estimated at $1.1Bln. This did not include a possible extension to the Envidia lobe.
- On May 14, 2014, Gran Tierra spudded a water disposal well in Bretaña (Bretaña Norte 95-2-2-1WD) and reached TD on May 17, 2014.
- The Bretaña Sur 95-3-4-1X was spud in Q4 2014 and abandoned in January 2015 after only finding six feet of oil pay above the oil-water contact in the Vivian Sandstone. This was much less than Gran Tierra was predicting for the location. As a result of the findings in Bretaña Sur 95-3-4-1X, the Bretaña reserves were expected to be reduced.
- On February 2, 2015, it was announced that employment of Gran Tierra's Chief Executive Officer and President Dana Coffield was terminated.
- On February 28, 2015, it was reported that the 2P and 3P reserves for Bretaña were reclassified as Contingent Resources in a report effective January 31, 2015. Gran Tierra ceased all further development expenditures in the Bretaña Field on Block 95 other than what was necessary to maintain tangible asset integrity and security. New executive appointments were announced on May 11, 2015.

Source: Eight Capital

Volumetrics

Effective June 30, 2017, NSAI estimated 2C resources (P50) of 330 Mmbbl Original Oil In Place (OOIP), a 12% recovery factor for a total of 39.8 Mmbbl recoverable oil.

Volumetrics

Block	Formation	Area (Acre)	Gross Pay (Feet)	Rock Volume (Acre-Feet)	N/G	Porosity	Sw	Shrinkage	OOIP (MBbl)
Block 95 - Bretana	Vivian	9,354	46	429,313	50%	23%	45%	0.95	199,490
Low		9,354		429,313					199,490

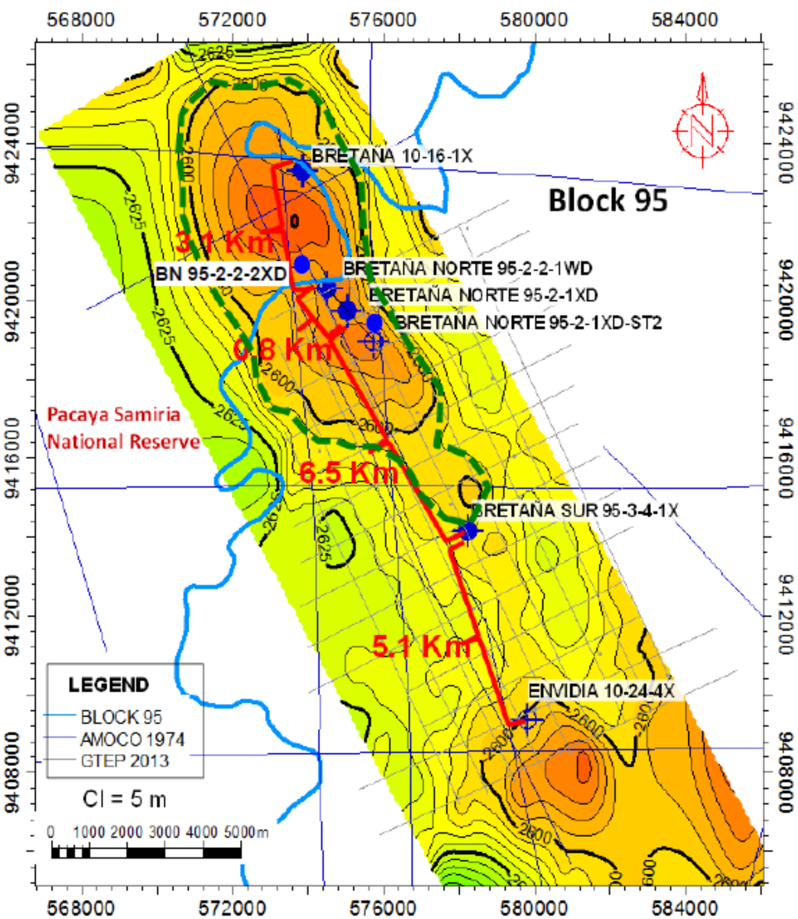
Block	Formation	Area (Acre)	Pay (Feet)	Rock Volume (Acre-Feet)	N/G	Porosity	Sw	Shrinkage	OOIP (MBbl)	Recovery Factor	Gross Recoverable (mbbl)
Block 95 - Bretana	Vivian	9,946	47	468,224	68%	23%	38%	0.95	329,205	12%	39,759
Best		9,946		468,224					329,205		39,759

Block	Formation	Area (Acre)	Pay (Feet)	Rock Volume (Acre-Feet)	N/G	Porosity	Sw	Shrinkage	OOIP (MBbl)
Block 95 - Bretana	Vivian	10,895	47	517,450	86%	22%	30%	0.95	503,470
High		10,895		517,450					503,470

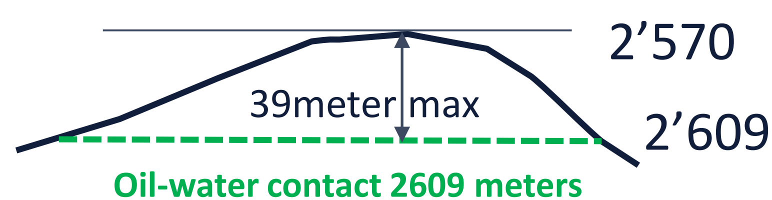
Source: Competent Person Report by Netherland, Sewell Associates, Inc (NSAI); Note: MMbbl =m blue barrels

Cross Checking Reserves

As at June 2019, Bretaña is defined by 7 wells, of which 3 are producing. It has an oil-water contact at 2,609 meters depth with a net pay of 32 feet (about 10 meters).



Diagrammatic cross section; Subsea depths
Note: Land surface circa. 105m above sea level.



- The 3-4-1X well came in deeper than predicted and encountered only a thin oil column, but helped to delineate the field area to the south.
- The northern portion of the field is covered by sparse 2-D seismic line while the south has more extensive coverage of 2-D and 3-D data.
- Net pay (height of oil column) is about 10 meters on average or about 32 feet;

Source: BGH analysis; Note: numbers in meters

Cross Checking Reserves (continued)

A quick cross check confirms 2P reserves of 36 – 91m barrels (Mmbbl).

Step 1 - Surface Area		
Width	km	4
Length	km	12
Surface	sqkm	48
Shape reduction	in %	80.0%
Surface net	sqkm	38
Surface net	acres	9,489

1

Reservoir Transmissibility Analog Table[1,2]	Bretaña
API (º Gravity)	18.5º
Oil Viscosity (cp)	28.0
Permeability (Darcy)	2.2
Net Thickness (Feet)	32.0
Water Saturation (%)	38%
Porosity (%)	23%
OOIP (MMBO)	330
EUR / 2C (MMBO)	39.8
Recovery (%)	12.0%

	Step 2 - Barrels per acre foot for field		Low	High
1	Porosity	in %	23%	23%
2	Oil Saturation	in %	62%	62%
3	Recovery Factor	in %	12%	30%
4	Barrels per acre foot	bbl	7,758	7,758
5	FVF Formation Factor	x	1.10	1.10
	Calc: 1x2x3x4 / 5	bbl	121	302

2

	Step 3 - Recoverable Oil		Low	High
1	Area Size	Feet	9,489	9,489
2	Net Pay	Feet	32.0	32.0
3	Barrels per acre foot	bbl	121	302
	Calc: 1x2x3	MMbbl	36.65	91.61

3

Source: BGH analysis; Note: Oil Saturation = 1 – Water Saturation of 38%; Barrels per acre foot of 7,758 is the norm; bbl = blue barrel
FVF = Formation Volume Factor.

Initial Production & Decline Rate

Production History

Bretaña has a young, but relevant production history of more than 1,5 million barrels of oil produced in 2018 & 2019. The two horizonal wells completed by PetroTal came in at Initial Production Rates (IP) of 6,200 and 8,250 bpd, respectively.

Production History (in barrels per day – bpd)

Year	Well Name	IP Rate bpd	Avg Rate bpd	Duration days	Comments:
03 July 2018	95-2-1XD	750	935	365	First producer; horizontal well as completed by Gran Tierra; This well was restricted (choked) due to facility limitations; Expected to increase rate to 2,000-2,300 bpd in 2019;
23 April 2019	95-2-2-2XD	2,250	2,350	45	Second producer; first horizontal well completed by PetroTal;
18 June 2019	BN-95-3H	3,500	3,500	2	Third producer; vertical completion by PetroTal;
21 October 2019	BN 95-4H	6,200	6,250	55	First modern horizontal well completion of Bretana field; 500m lateral
16 December 2019	BN 95-5H	8,250	8,250	3	Second modern HZ well with 750m lateral

Note:

IP Rate Initial Production for 24 hours

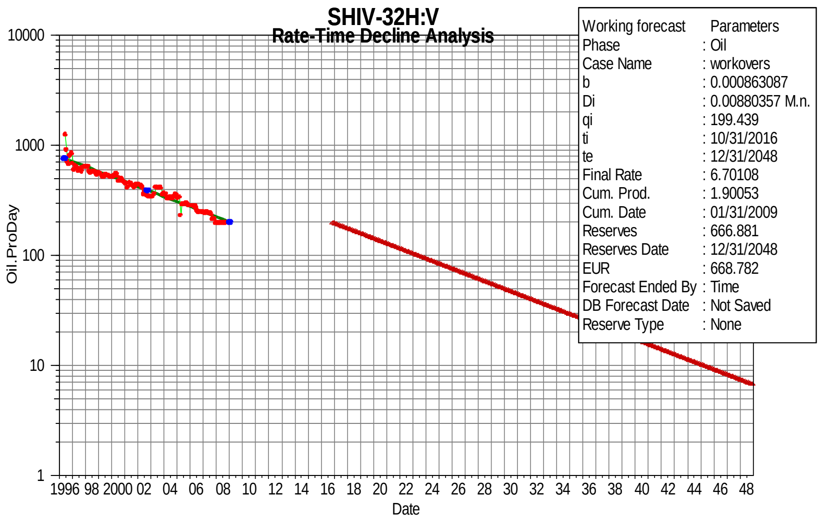
- The initial production rate measures how many barrels of oil a day a new oil well produces;
- It is used as a proxy for an oil well's future productivity;
- Initial production rates are reported inconsistently, but companies increasingly use 24-hour, 30-day, 60-day and 90-rate periods.

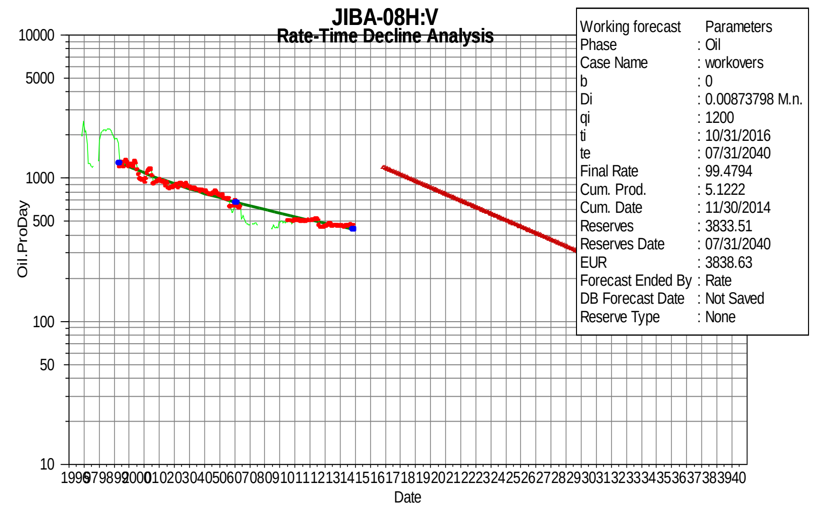
 Source: BGH analysis; company filings

Historic Decline Rates

Two wells from analogue fields in the Vivian formation have declines of 0.9% monthly or about 11% per annum.

Analgue Decline Rates: Shiviyacu & Jibaro / Jibarito





Well Name		SHIV-32H	JIBA-08H
Monthly	decimal	0.00880357	0.00873796
Monthly	in %	0.88%	0.87%
Annual	**in %**	**11.09%**	**11.00%**

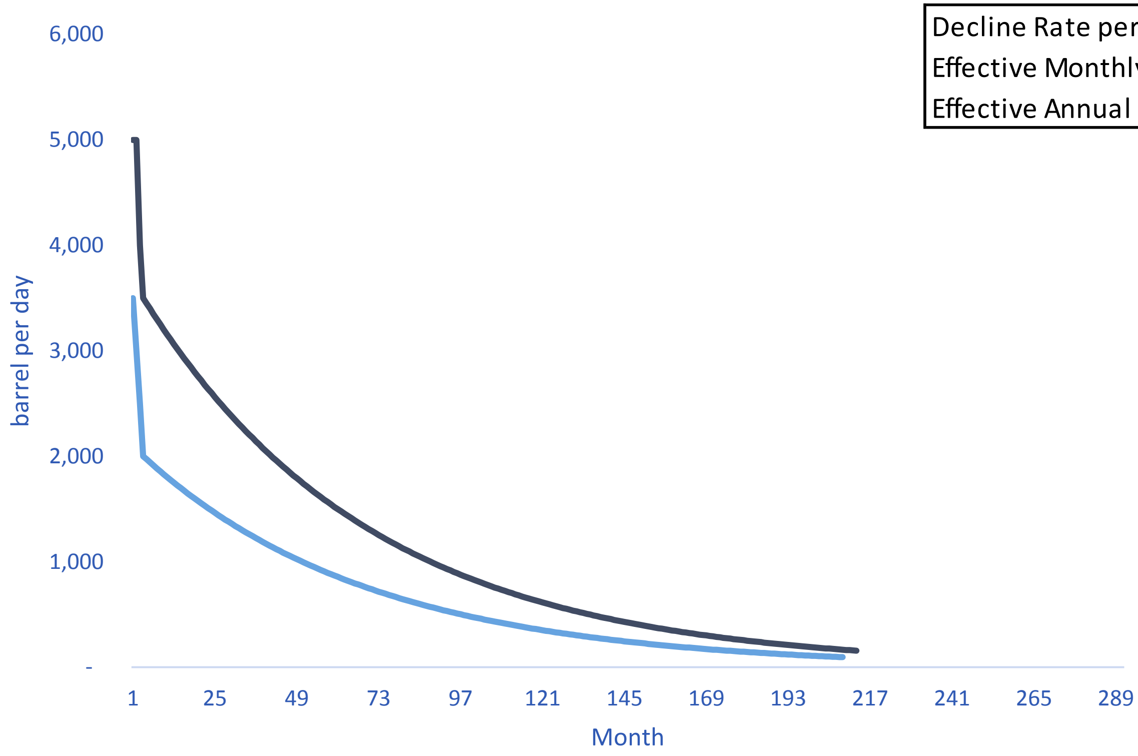
Source: BGH analysis; Well Data from PetroTal for BGH

Type Curve

For our valuation, we used our proprietary two type curve model (well types) to reflect wells further away from and closer to the water cut. We assume an average well to produce for 18 years, with annual decline rates of 19.3%.

2 Type Curves: IP Rate 5,000 bpd & IP Rate 3,500 bpd (each for 30 days)

Decline Rate per month	**1.480%**
Effective Monthly Decline Factor	1.0148
Effective Annual Decline Factor (DF3P)	1.1928



Source: BGH analysis

Decline Curve Analysis

Based on the initial production data and our decline curve analysis, the reserve report is certainly far too conservative. But it is early days…

Assessment

- At the time of publishing the reserve report by NSAI, there were no production data available for their 2P Reserve estimates;
- Today, we are privileged to have production data from a total production of 1,500,000 barrels of oil produced at Bretaña;
- More importantly, we have the Initial Production (better known as IP Rates) of two modern horizontal wells which were completed with 500 & 750 meter laterals, respectively, and equipped with modern electrical submersible pumps (ESP).
- Also note that the first horizontal well was able to increase initial production over its 55 days, from 6,200 to 6,300 barrels per day. This is despite the lowest possible configuration for the ESP as otherwise the oil produced would have surpassed the field's current capacity limitations (mainly for daily oil storage).
- Initial production rates are reported inconsistently, but companies increasingly use 24-hour, 30-day, 60-day and 90-day initial production rate periods. Initial production rates are important because they allow to extrapolate a well's total production, its peak production level and the rate at which production will decline – using a decline curve analysis.
- We have done a decline analysis for Bretaña, assuming an IP rate of 5,000 bpd – a rate lower than both IP rates from the horizontal wells completed by PetroTal. This makes sense as not all 11 wells will deliver equal rates. In general, the closer a well is located to the water cut line, the lower its rate. We have also used a higher decline rate than previous analogue fields yielded.
- **The result confirms that NSAI 2P reserves are FAR too conservative. At an annual decline of 14% per well, 11 HZ wells at an IP rate of 5,000 barrels (or about 4,100 barrels in months six) would yield up to 107 million barrels of reserves!**
- But of course, it is too early to conclude on the trend of the reservoir. We do not have sufficient horizontal production days just yet.

Reserve Sensitivity (in Mmbbl)

<----------------- Monthly Decline Rate --------------------->

97.58	1.50%	1.30%	1.10%	0.90%	0.70%
3,000	46.5	53.6	61.8	74.3	92.2
4,000	63.8	72.3	84.9	101.7	122.9
5,000	80.6	92.1	106.9	128.0	153.6
6,000	97.6	111.3	129.9	153.7	184.4
7,000	114.7	130.6	152.3	179.3	215.1
IP Rate	**19.6%**	**16.8%**	**14.0%**	**11.4%**	**8.7%**

<----------------- Annual Decline Rate --------------------->

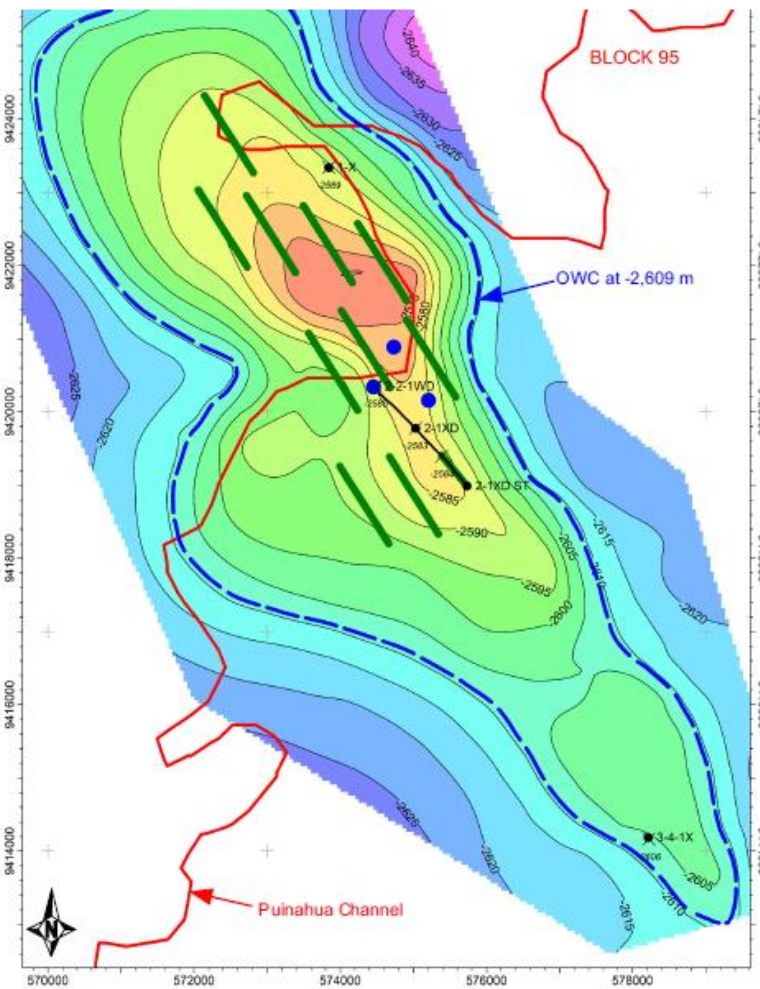
<u>Assumptions:</u>

IP Rate	6,000	barrels per day (bpd)
Period	60.0	days, period at which rate remains steady
Decline	10%	Monthly decline bw. 3rd and 6th month
6 Mt Rate	4,098	bpd, production rate end of month 6
Avg Decline	14.0%	Annual decline rate after month 7
No of wells	11	Horizontal Producing Wells
Field Life	2,000	bpd, i.e. field is shut below this field rate

Production

Development Plan

PetroTal intends to develop the field with 11 horizontal and 3 water disposal wells.



Legend

- Proved Plus Probable Development Well Location
- Water Disposal Well Location
- Oil Well
- Penetration Point

Bretaña Field
Block 95, Onshore Peru

Depth Structure
Top Vivian Formation

Contour Interval: 5 meters

SCALE IN METERS

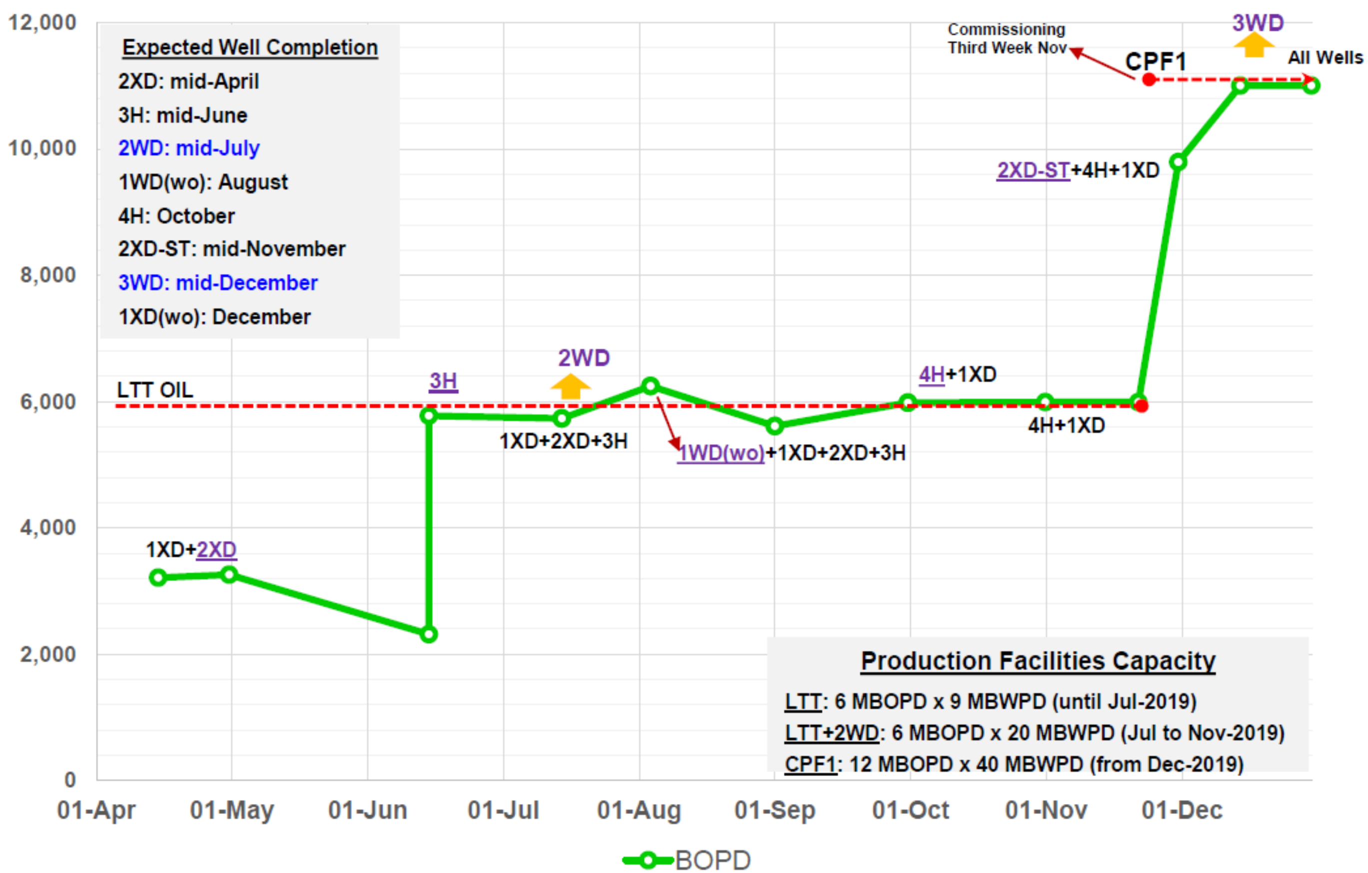
0 1,000 2,000 4,000

 Source: CPR 2018

Production Forecast

PetroTal originally guided for a production of 11,000 bpd by mid January 2020. In November, this was increased to 11,000 – 13,000 bpd.

2019 Production Forecast by PetroTal Management

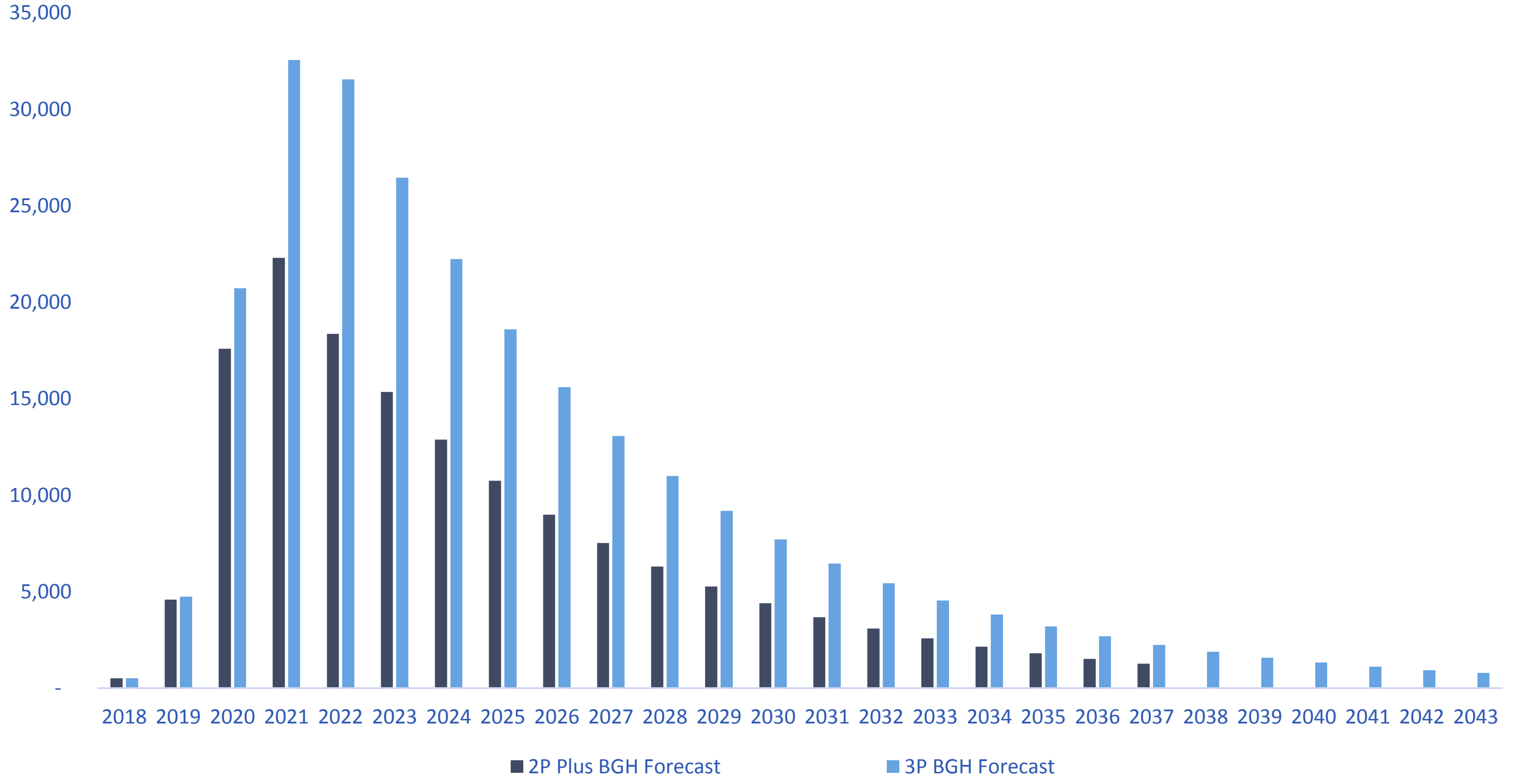


Source: Company filings

Production Forecast

For the below forecast, we modelled Bretaña in detail and on a per well basis, in accordance with the 2P "Plus" & 3P field development plan and today's well results.

Our Production Forecast (in bpd) for 55.5 Mmbbl & 91.2 Mmbbl Reserves

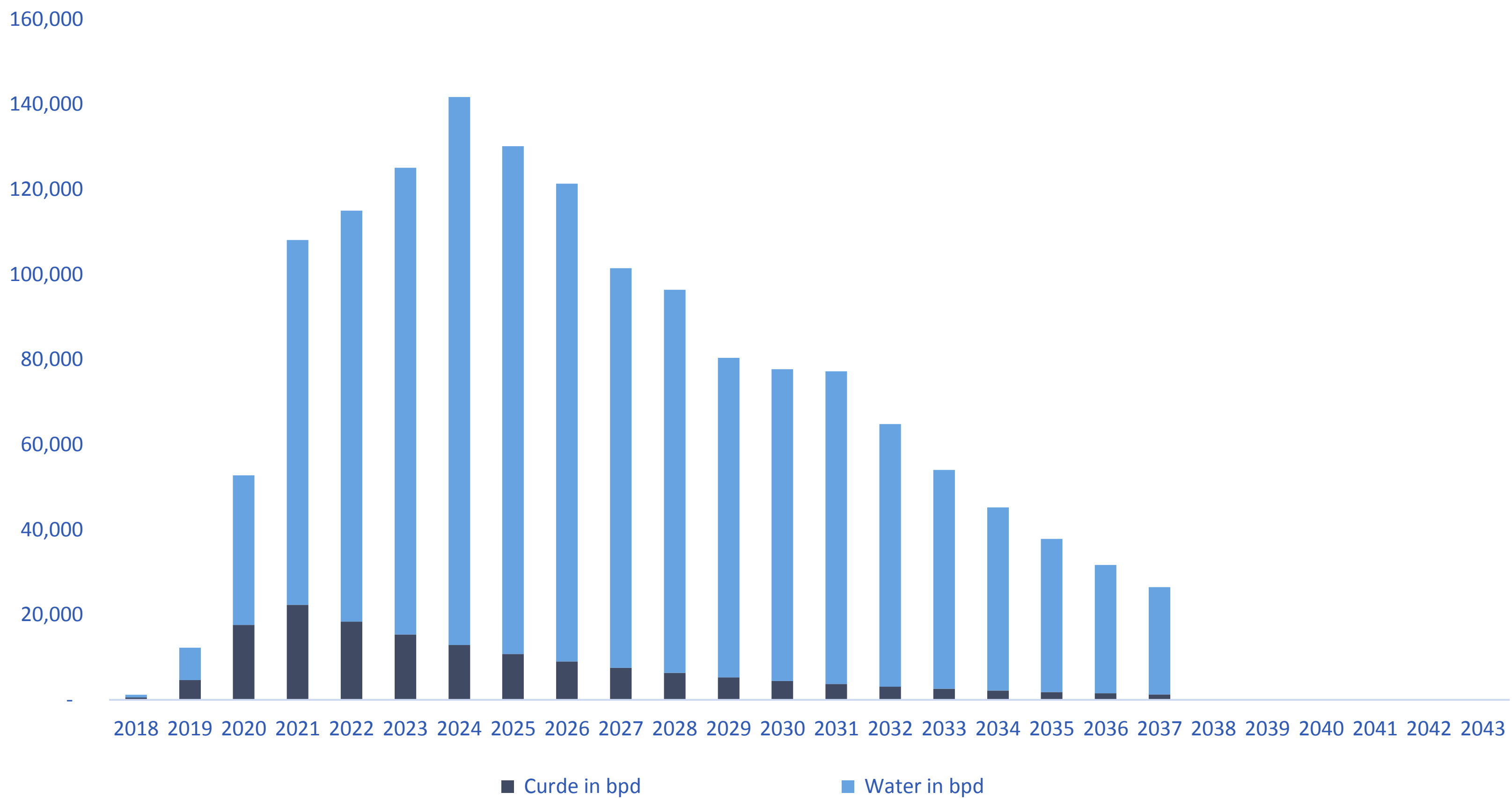


Source: BGH analysis

Oil & Water Production Profile

We assume significant water cut in our production model to reflect the nature of the reservoir.

Oil & Water Production Profile (in bpd) for 2P "Plus" Reserve Model



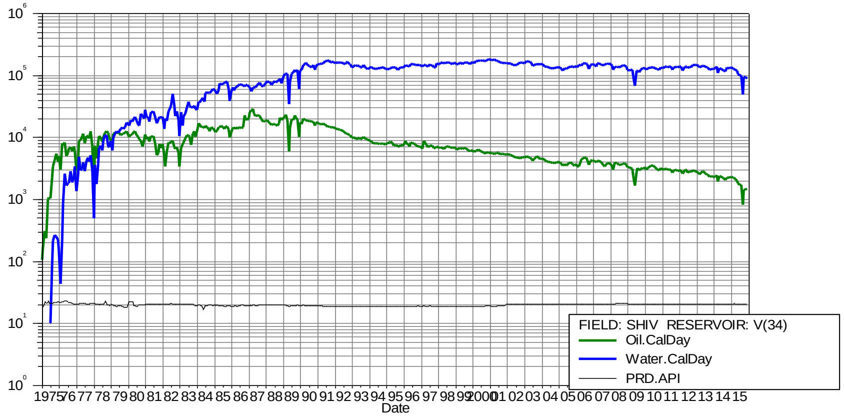
Source: BGH analysis

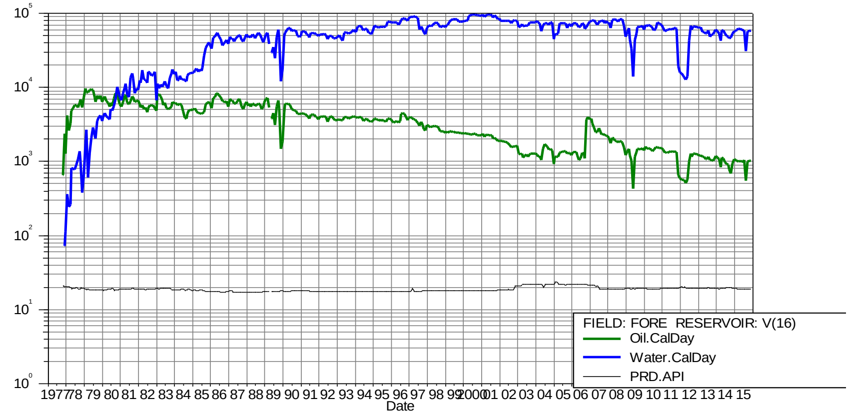
Water Cut

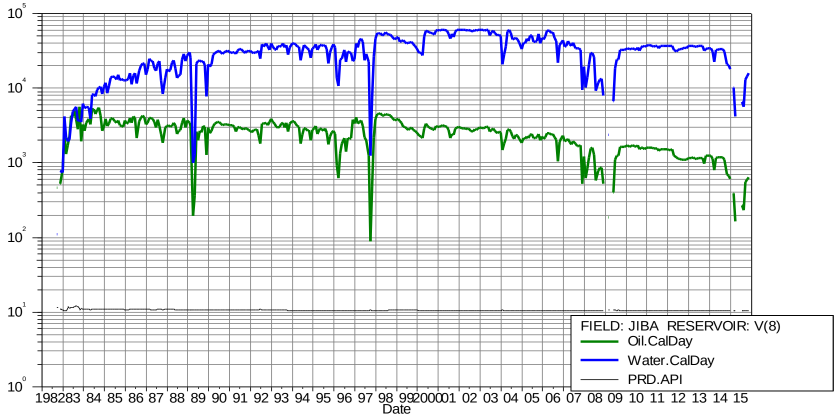
Analogue Field Oil-Water Production Profiles

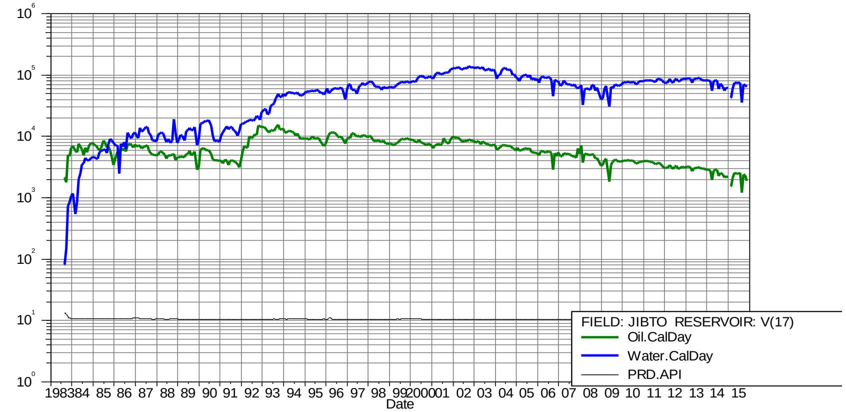
The Vivian Formation – of which Bretaña is part – has a history of producing significant water along the oil.

Vivian Reservoir Behaviour: Shiv, Fore, Jiba, Jibto







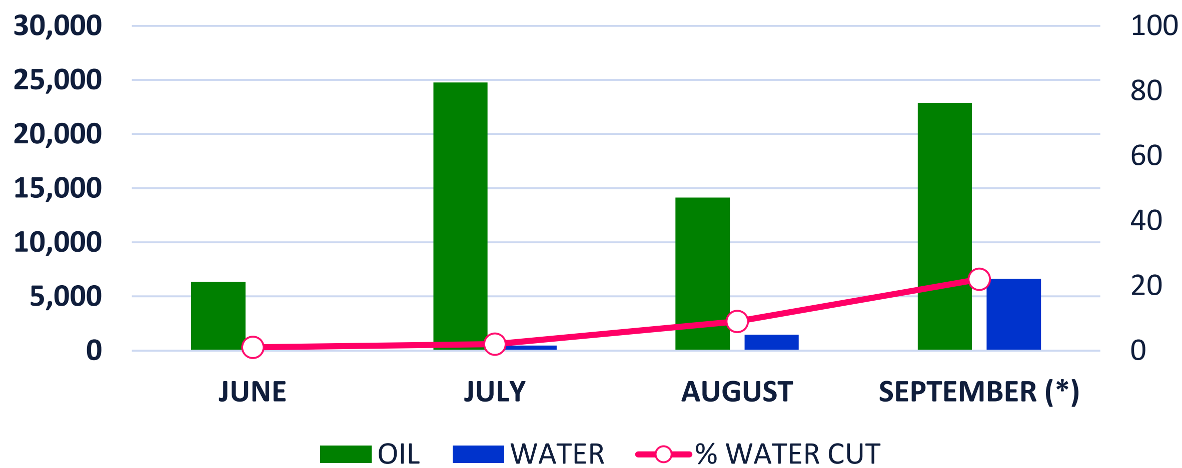


 Source: PetroTal for BGH

Initial Oil – Water Cut

Bretaña's 120 days production results already produce water. Water production is often considered an "early warning sign" for overall oil recovery. But not in Peru…

Bretaña: Monthly Oil – Water Production Profile 2018

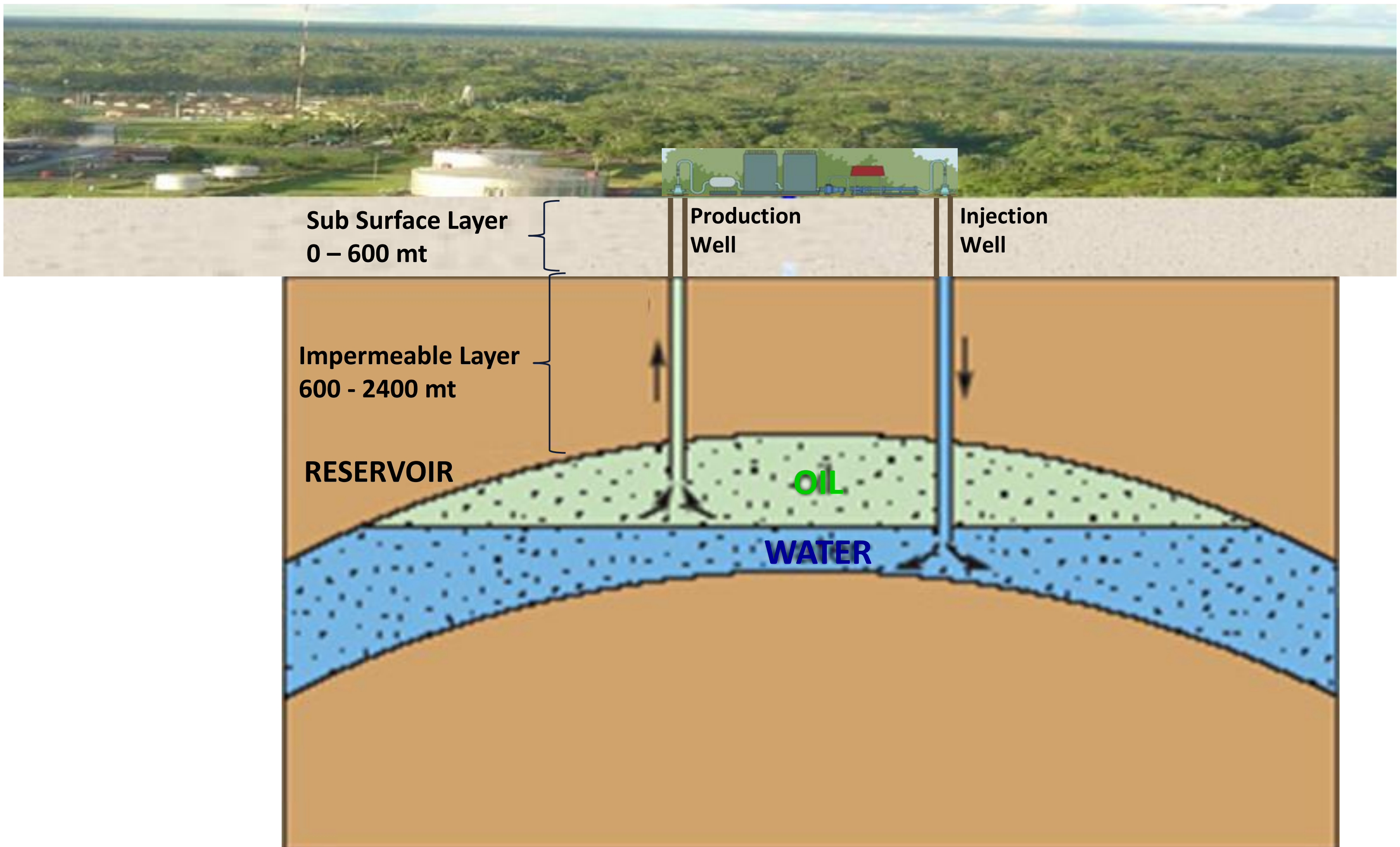


BARRELS PER MONTH	JUNE	JULY	AUGUST	SEPTEMBER (1)
OIL	**6,331**	**24,759**	**14,145**	**22,859**
WATER	64	472	1,464	6,621
TOTAL FLUID	6,395	25,231	15,609	29,480
WATER CUT (%)	**1**	**2**	**9**	**22**

Source: PetroTal for BGH; Note 1: until 25 September 2018

Active Aquifer

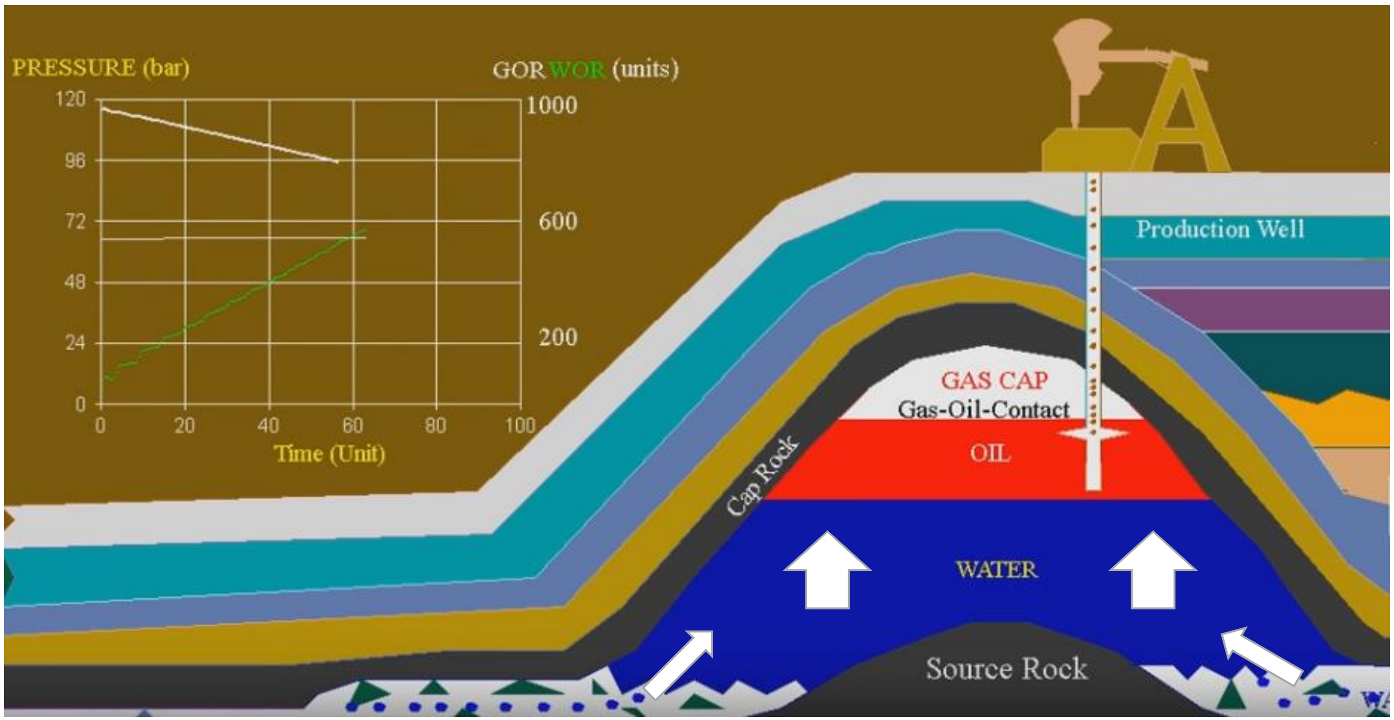
…this is because fields in the Vivian Formation in the Amazonian are underlain by active aquifers that provide a strong bottom-water drive.



Water is Your Friend

This “natural energy” of the reservoir helps to move the oil toward the wellbore without expensive stimulation. In other words, the water aquifer is a “friend” when recovering oil.

Schematic of reservoir with strong bottom-water drive

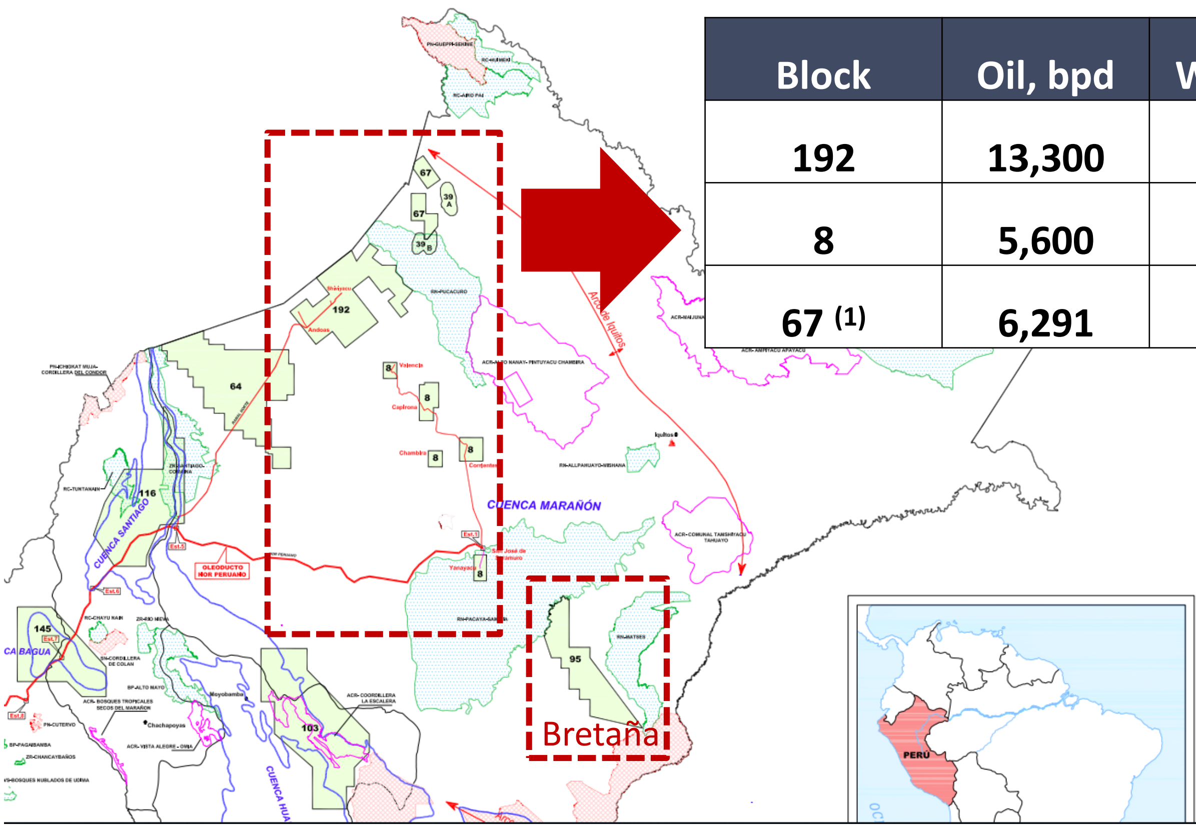


 Source: https://www.youtube.com/watch?v=be9sMvIvFtM

Water Production

Analogue fields suggest water production of up to 98% along with the ultimate oil recovered. This requires water facilities and proper reservoir management.

Selected Analogue Fields: Percentage of Water Production



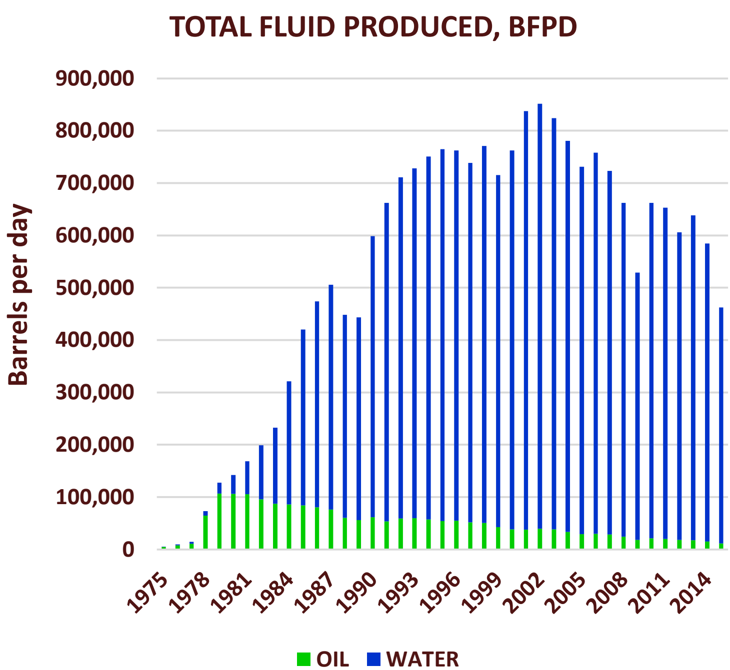
Block	Oil, bpd	Water, bpd	Water Cut, %
192	13,300	430,033	97%
8	5,600	274,400	98%
67 (1)	6,291	8,427	57%

 Source: PetroTal for BGH; Note 1: Peak Production in November 2014

Oil-Water Production Profile Block 192

For example, Block 192 produced a total of 97% water cut in 2014.

Block 192, Peru



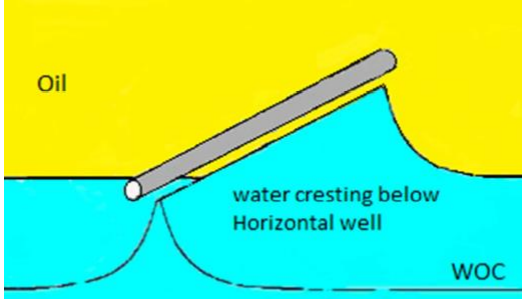
Production Facilities Block 192, Peru

Oil, bpd	Water, bpd	Water cut, %
13,300	430,033	97%

Managing Water Coning

PetroTal is applying a horizontal well development strategy in order to manage “coning” and maximize the recovery factor.

What is “water coning” in a strong bottom-water drive reservoir?



- In strong bottom-water drive reservoirs, oil production from wells in these reservoirs lead to changing pressure drawdown around the wellbore. This causes a movement of the oil/water interface toward the producing interval (see left hand side picture).
- To develop bottom-water reservoirs with active aquifers requires a production strategy that can handle this phenomenon, named water coning (for vertical wells) and termed water cresting in horizontal wells.
- In the petroleum industry, the use of horizontal wells in the production of oil and gas is not limited to increasing the well productivity but also to reducing the number of producing wells, thereby effectively draining the reservoir more effectively.
- Horizontal wells however are also used as a water coning attenuation approach, especially in thin-oil column reservoirs with strong active bottom-water drive like Latin America. And yes, PetroTal is applying a horizontal well development strategy (see link here).
- Vertical wells exhibit a larger pressure drawdown in the wellbore vicinity than horizontal wells. Therefore, horizontal wells provide an option whereby pressure drawdown is minimized and high production rates sustained. In addition, at low drawdown, horizontal wells can have a larger capacity to produce oil compared to conventional vertical wells. However, the problem of water coning is still experienced.
- **Eventually, the PetroTal team on the ground will have to manage water coning by finding the optimal production rate to minimise coning and maximising the overall recovery. In our view, much of that comes down to having an experienced local team that has dealt with this type of reservoir before.**

Source: BGH analysis; https://www.semanticscholar.org/paper/Water-Coning-Prediction%3A-An-Evaluation-of-Well-Okon-Appah/ae0f1d49b6767ad8fc38fa0a8698896dda9d087f

Relevant Experience

The PetroTal team understands the development of Peruvian reservoirs…

Peruvian Project Experience of Today's PetroTal Team (June 2018)

Region	Block / Field	Basin	Peak Daily Production[1]	Recovery To Date[1]	Explored	Discovered	Developed
Jungle – Vivian / Chonta	**Block 192 (1-AB)**	**Marañón**	**106,180 bopd**	**719 MMBO**	✔	✔	✔
Jungle – Vivian / Chonta	Block 8	Marañón	41,593 bopd	297 MMBO	✔	✔	✔
Jungle – Vivian / Chonta	**Block 107**	**Ucayali**	**–**	**–**	✔		
Jungle – Vivian / Chonta	Block 56/88 Camisea	Ucayali	286,000 boepd	760 MMBOE	✔	✔	✔
Northwest Peru	Block 22 / 23	Lancones / Tumbes	–	–	✔	✔	
Northwest Peru	**Block 11**	**Talara**	**19,560 bopd**	**61 MMBO**	✔	✔	✔
Northwest Peru	Block Z-1	Tumbes	8,000 bopd	11 MMBO	✔	✔	✔
Northwest Peru	Block Z-2B	Talara	35,000 bopd	360 MMBO	✔	✔	✔

Team Member	Position	Relevant Experience from Occidental[2]	Occidental Tenure
Jim Taylor	Director	• Discovered & developed giant Caño Limón oilfield in Colombia • Involved in Block 1-AB appraisal & development • COO of Canadian Occidental, directed the discovery & development of the giant Masila oilfield in Yemen	28 years
Gary Guidry	Director	• President & General Manager in Nigeria • Manager Petroleum Engineering in Yemen • Chief Reservoir Engineer in Venezuela	18 years
Estuardo Alvarez-Calderon	Manager Exploration & Development	• Senior roles at Occidental spanning the Americas • Exploration Manager for Peru including Block 1-AB. • Having published many technical papers, he is recognized as an expert of Peru's northern jungle	28 years
Luis Pantoja	Production Engineer	• Occidental production engineering supervisor for Block 1-AB. • Set standards for ESP performance and water disposal wells in Block 192 (1-AB) • Led the production and engineering operations in Pluspetrol's Camisea Field	18 years
Antonio Zegarra	Reservoir Engineer	• Experience spans Oman, Qatar, Libya • Marañón & Talara basins in Peru, including Block 1-AB where he led reservoir management to optimize oil production while minimizing water production	34 years
Orestes Orrego	Operations Geologist	• Geologist involved in Occidental projects spanning Qatar, Libya, Yemen, Russia, Venezuela, Paraguay, Bolivia, Colombia, Texas (Permian), and Block 1-AB	35 years

- Previously held by Occidental (in Bold)

Source: Company filings

Recovery Factor & OOIP

Bretaña Reserve Report

The Competent Person Report (CPR) suggests 2P reserves of 39.8 MMbbl of oil for Bretaña when applying a recovery factor of 12%. 3P reserves are estimates to be 79.2 MMbbl with a recovery factor of 16%.

Block 95 (Bretaña): Reserve Report (in '000 bbl and US$m)

	Category	Oil Reserves[1] (MBBL) Gross	Net	Future Net Revenue[2] (M$) Total	Present Worth at 10%
	Proved Undeveloped	15,271.0	15,271.0	150,435.3	93,522.6
	Probable Undeveloped	24,488.3	24,488.3	563,055.6	311,540.8
2P Reserves	Proved + Probable	39,759.3	39,759.3	713,490.9	405,063.4
	Possible Undeveloped	39,522.7	39,522.7	1,357,866.6	590,627.4
3P Reserves	Proved + Probable + Possible	79,282.0	79,282.0	2,071,357.4	995,690.8

Totals may not add because of rounding.

(1) PetroTal owns a 100 percent working interest and 100 percent net revenue interest in these properties.
(2) Future net revenue includes deductions for PetroTal's sliding scale government royalty payments.

In the proved reserves case, 8 horizontal producing wells and 2 water injection wells are estimated to recover approximately 15.3 million barrels of oil that yield a RF of 10 percent.

In the proved plus probable reserves case, the estimated total recoverable oil is approximately 39.8 million barrels of oil that yield a RF of about 12 percent. To develop these reserves, 11 horizontal producing wells and 3 water injection wells will be required. The production wells are spaced approximately 400 m apart with 6 deviated horizontal producing wells along the crest of the structure to the northwest, and 5 deviated

In the proved plus probable plus possible reserves case, 17 horizontal producing wells and 5 water injection wells are estimated to recover approximately 79.3 million barrels of oil that yield a RF of 16 percent. This case uses the proved plus probable reserves case as a starting point and adds 6 additional producing wells to capture bypassed oil 2 years after the initial development.

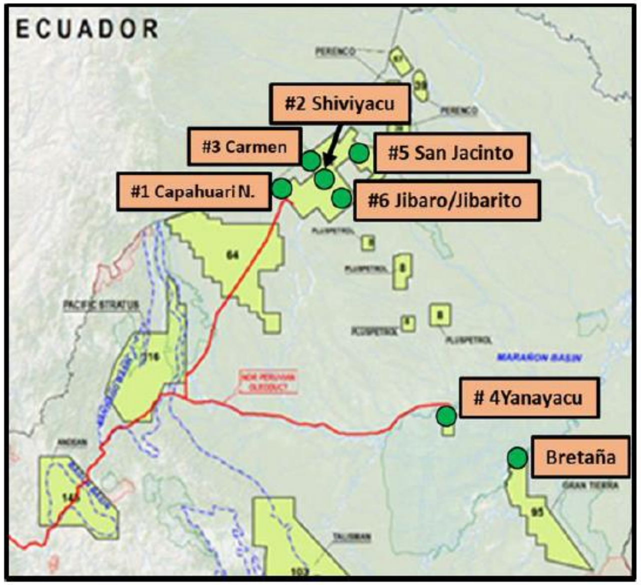
Source: CPR 2018 by Netherland, Sewell & Associates, Inc., page 35, 5 and 6 (NSAI)

Management View on Recovery Factor

Management seems to suggest that a 12% recovery factor of original oil in place (OOIP) may prove to be conservative as 3x more oil has been recovered in analogue fields.

PetroTal Statements on Bretaña's Recovery Factor

- Bretaña estimated 2P recovery factor of 12% is based on data set of three wells & one core
- Every analog field in region has achieved >12% recovery factor (ranging from 19.1% to 41.6%[1])
- NSAI has already increased the 1P recovery factor by 23%, from 7.4% to 9.1%[2]
- These analog fields benefitted from horizontal reservoir barriers that slowed down the water coning – also seen in Bretaña's core
- Management believes that Bretaña has similar reservoir barriers and could deliver >24% Recovery Factor



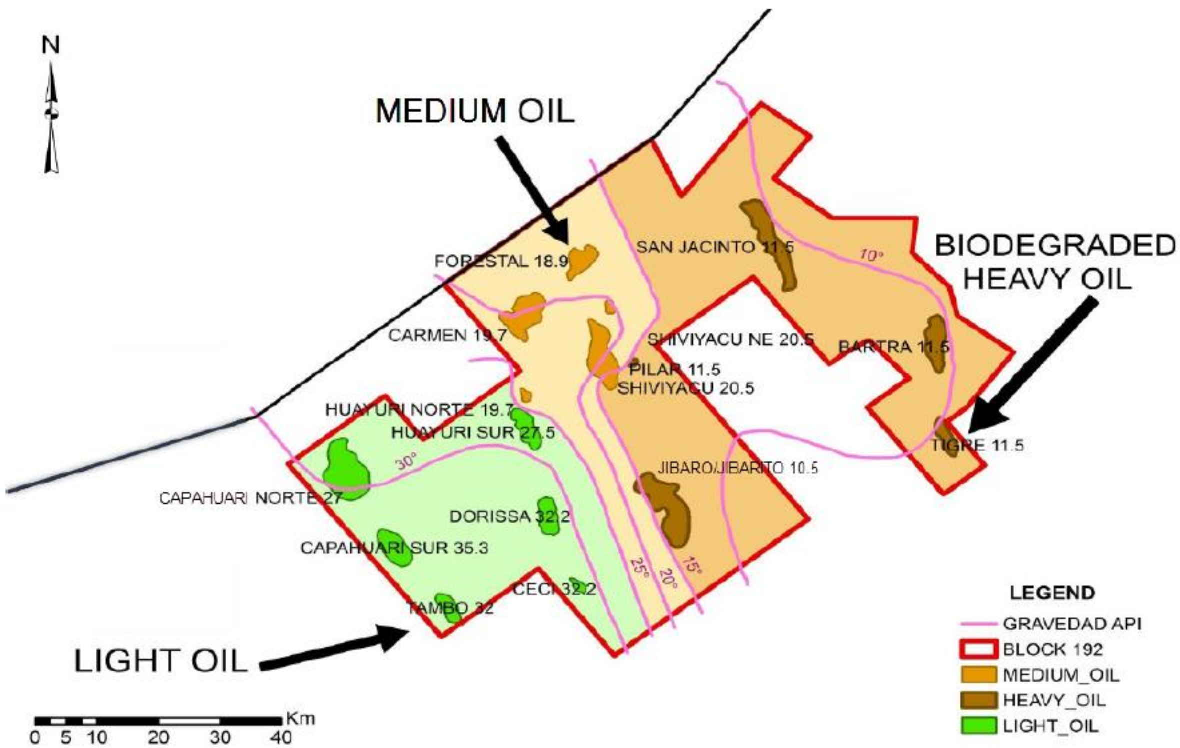
Reservoir Transmissibility Analog Table[1,2]	Bretaña	#1 Capahuari N.	#2 Shiviyacu	#3 Carmen	#4 Yanayacu	#5 San Jacinto	#6 Jibaro/Jibarito
API (º Gravity)	19.4º	35.2º	20.2º	19.7º	19.0º	12.5º	10.8º
OOIP (MMBO)	330	48	331	45	65	209	414
EUR / 2P (MMBO)	39.4	20.0	120.8	13.5	23.6	46.3	103.2
Recovery (%)	12.0%	41.6%	36.4%	29.9%	36.1%	22.2%	24.9%

Source: PetroTal; Note: Reservoir Transmissibility = Permeability x Thickness / Viscosity

Analogue Fields

Perupetro identified 16 analogue fields in block 192 of the Vivan Basin to better understand Recovery Factor.

Vivian Basin: 16 Analogue Fields in Block 192



 Source: Perupetro

Analogue Fields Recovery Factors

The 16 analogue fields of the Vivian Basin in Peru had 2.5 billion of OOIP and produced 665 MMbbl crude oil for a weighted average Recovery Factor (RF) of 27% and 32% for similar API ranges (medium-heavy oil).

Recovery Factors (in %) of 16 analogue fields in the Vivian Basin

	Field	Type Crude	API	OOIP (Mmbbl)	RF (MMbbl)	RF (in %)
1	Capahuari Sur	Light	35.0	328	148	45.1%
2	Dorissa	Light	32.0	124	64	51.6%
3	Huayuri Sur	Light	28.0	77	24	31.2%
4	Capahuari N	Light	27.0	52	20	38.5%
5	Pavayacu	Light	27.0	41	17	41.5%
6	Tambo	Light	27.0	19	1	5.3%
6	**W-Average Light Oil**			**641**	**274**	**42.7%**
1	Shiviyacu	Medium	20.0	331	121	36.5%
2	Forestal	Medium	18.0	123	48	39.3%
3	Carmen	Medium	22.0	84	13	15.5%
4	Yanayacu	Medium	18.0	60	16	27.0%
5	Huayuri Norte	Medium	21.0	31	3	9.7%
6	Corrientes	Medium	24.0	14	5	35.7%
6	**W-Average Medium Oil**			**643**	**206**	**32.1%**
1	Jibaro / Jibarito	Heavy	10.5	530	104	19.6%
2	San Jacinto	Heavy	12.0	467	47	10.0%
3	Bartra	Heavy	11.0	154	30	19.7%
4	Shiviyacu Norte	Heavy	16.0	22	3	13.6%
4	**W-Average Heavy Oil**			**1,173**	**184**	**15.7%**
16	**Total Weighted Avg**			**2,457**	**665**	**27.0%**

Bretaña: API 19.4 degree

Source: BGH analysis; Perupetro; Eight Capital; Note: RF = Recovery Factor

API Matters

The oil sample from Bretaña analysed by Bureau Veritas in Houston in November 2018 concluded an API of 19.4 degree, suggesting a higher RF than used by NSAI for the Reserve Report.

- As we explained in the Geology section of this paper, the Vivian "A" Sand is supported by a strong bottom water drive. Vivian "B" Sands may also derive pressure support from edge water drive. The Block 192 and Block 8 fields have been producing since the mid to late 1970's and are all producing at >97% water cut. The table on the previous page show the OOIP, cumulative recovery to YE13 and the recovery factor for the 16 Vivian fields in the basin. Two factors are apparent in examining the data:
  - **(a)** Oil gravity appears to have the greatest impact on the recovery factors (RF) - in general, the lighter the gravity of the oil, the higher the recovery factor; and
  - **(b)** larger fields have shown slightly higher recovery factors than smaller fields.
- **There is more. In its evaluation, Netherland, Sewell & Associates (NSAI) characterized Bretaña Norte oil as undersaturated, 18.5°API oil with a 28 cP viscosity and a 25 Scf/Bbl Gas Oil Ratio (GOR). In November 2018 however, the Bureau Veritas in Houston confirmed that Bretaña produces 19.4°API and 17.8 cP.**
- Remember and as illustrated on the previous page, recovery factors in the basin are highly dependent on oil viscosity. The water cut of medium, and especially heavy, oil reservoirs increase very fast to values >90% in the early stages of exploitation due to the differences in mobility between the viscous oil and the formation water. This matters for two reasons:
  - (a) The reduction in measured oil viscosity (higher API) should improve the reservoir’s transmissibility and thus its ultimate recovery factor; and
  - (b) the higher API should reduce the well-head discount somewhat (today 14% discount to Brent).
- NB: the Forestal Field in Block 192 produces 18.9°API oil with a 4 cP viscosity and has recovered 39% of its OOIP and the Jibaro-Jibarito Field in Block 192 produces 10.7°API oil with a 66 cP viscosity and has recovered 19% of its OOIP.
- **We therefore conclude that the size of Bretaña and its API justify a recovery rate of between 25-35%. Our Upside Case will model the Bretaña with a Recovery Rate of 30%.**

Source: BGH analysis; CPR; Eight Capital; Note: RF = Recovery Factor

Original Oil In Place (OOIP)

The best estimate average gross pay of the reserve report by NSAI for the structure is 47 feet. Net pay is 32 feet. The net to gross ratio assumed is 68%.

Bretaña Volumetrics

Block	Formation	Area (Acre)	Gross Pay (Feet)	Rock Volume (Acre-Feet)	N/G	Porosity	Sw	Shrinkage	OOIP (MBbl)	Recovery Factor	Gross 2P Reserves (MBbl)
Block 95 - Bretaña	Vivian	9,946	47	468,224	68%	23%	38%	0.95	329,205	12%	39,759
Best		**9,946**		**468,224**					**329,205**		**39,759**

Block	Formation	Area (Acre)	Gross Pay (Feet)	Rock Volume (Acre-Feet)	N/G	Porosity	Sw	Shrinkage	OOIP (MBbl)	Recovery Factor	Gross 3P Reserves (MBbl)
Block 95 - Bretaña	Vivian	10,895	47	517,450	86%	22%	30%	0.95	503,470	16%	79,282
High		**10,895**		**517,450**					**503,470**		**79,282**

- Netherland, Sewell & Associates, Inc. (NSAI) estimated the recoverable reserves in the Bretaña Field effective June 30, 2018.
- NSAI estimates 2P reserves at 39.8 MMBbl based on a 12% recovery of 329 MMBbl OOIP.
- On 23 April 2019, PetroTal gave an update on its second oil well, named BN 95-2-2-2XD (link). It had an Initial Production Rate (IP) of 2,250 barrels of oil per day (bopd).
- On 28 May 2019, PetroTal reported that the well averaged 2,300 bpd over 30 days (link).
- On 21 October 2019, PetroTal reported that its first horizontal well averages 6,200 bpd and since increased to 6,250 bpd with the lowest possible ESP configuration (link);
- On 16 December 2019, PetroTal reported 8,250 bpd for the second horizontal well (link);
- On the next page, we will compare the two data sets to confirm the Original Oil In Place (OOIP) as provided by the Reserve Report.

Source: Company filings; Eight Capital

More Original Oil In Place (OOIP)?

The first well data from BN 95-2-2-2XD supports the 2P OOIP best estimate of 329 MMBbl and may suggest an upward bias of up to 45 MMBbl.

Bretaña BN 95-2-2-2XD Well Update

- Comparing the BN 95-2-2-2XD data so far to the NSAI volumetric estimates, we see:
  - The best estimate average gross pay of the reserve report by NSAI for the structure is 47 feet (link).
  - Management indicated that BN 95-2-2-2XD was drilled near the crest of the structure and encountered **79 feet of gross pay**.
  - Additional wells are required to confirm average net pay, but management is pleased that the well came in on prognosis and believes that the 79 feet of gross pay near the crest supports an average net pay estimate of 47 feet for the structure.
  - Net Vivian pay in BN 95-2-2-2XD was 61 feet which calculates out at a net-to-gross (N/G) ratio of 77%. This compares with the best estimate of 68% of the reserve report (link).
  - **Using 13% more net pay for the reservoir, i.e. 78% N/G versus the 68% (or 78/68) adds another 45 MMBbl OOIP to the Bretaña structure. See table on the right hand side.**
  - Log porosities in BN 95-2-2-2XD agree with the 23% estimate (link).
  - Water saturation will be calculated with a fluid sample from the well.
- **Overall, data from BN 95-2-2-2XD supports the 2P OOIP best estimate of 329 MMBbl and may suggest an upward bias of up to 45 MMBbl.**

Original Oil in Place (OOIP)

Step 1 - Barrels per acre foot for field		NSAI	2XD
Porosity	in %	23%	23%
Oil Saturation	in %	62%	62%
Recovery Factor	in %	100%	100%
Barrels per acre foot	bbl	7,758	7,758
FVF Formation Factor	x	1.05	1.05
Calc: 1x2x3x4 / 5	bbl	1,051	1,051

Step 2 - Original Oil in Place (OOIP)		NSAI	2XD
Area Size	Feet	9,946	9,946
Net Pay	Feet	32.0	36.3
Barrels per acre foot	bbl	1,051	1,051
Calc: 1x2x3	MMbbl	334.50	379.35
Upside			**44.86**

Source: BGH analysis; Company filings; Eight Capital; MMbbl = million barrels; Note: recovery factor 100% to calculate OOIP.

Reserve Potential

Our assessment from existing data (on both analogue fields and well data) suggests that the Competent Person Report by NSAI is far too conservative.

Trend of Reservoir after two horizontal well updates

23/06/2019	NSAI	Trend	Upside
Original Oil In Place (OOIP)	330	379	15%
Recovery Factor (RF)	12%	30%	150%
2P Reserves (in MMbbl)	**39.6**	**113.8**	**187%**

Source: BGH analysis

Operation

Investment Budget

We assume a total of US$333m or $8.4/2P Plus reserve of capital invested.

Capital Budget Breakdown (in US$m)

Investments, in US$		Total	2016E	2017E	2018E	2019E	2020E	2021E	2022E
Facility:									
Engineering	US$ '000	762	0.0	0.0	462	300			
Base Camp Maintenance and Construction	US$ '000	3,567	0.0	0.0	1,067	2,500			
Logistics	US$ '000	4,616	0.0	0.0	2,116	2,500			
Oil Production Facilities	US$ '000	40,643	0.0	0.0	4,643	10,500	15,000	10,500	
Water Treatment and Reinjection Facility	US$ '000	54,797	0.0	0.0	4,797	20,000	10,000	10,000	10,000
Total Facilities	US$ '000	**104,386**	**0**	**0**	**13,086**	**35,800**	**25,000**	**20,500**	**10,000**
Drilling:									
Dayrate of Saipem rig (all-in; excluding materials)	US$ per day					29,000	29,000	29,000	
Average days for one well	days	1,074.0				358	358	358	
Cost of drilling wells	US$ '000	31,146	0	0	0	10,382	10,382	10,382	0
Completion cost	US$ '000	100,036				54,418	45,618		
Mobilisation Fee	US$ '000	7,820				4,700	3,120		
Total drilling cost	US$ '000	**163,620**				**69,500**	**59,120**	**35,000**	
Producing Wells	x	**12.0**				**5.0**	**7.0**		
Drilling Platform Maintenance and Expansion	US$ '000	2,620	0.0	0.0	2,020	500	100	0	0
Drilling: well intervention & development drilling	US$ '000	163,620	0.0	0.0	0.0	69,500	59,120	35,000	0
Total Drilling	US$ '000	**166,240**	**0**	**0**	**2,020**	**70,000**	**59,220**	**35,000**	**0**
Others:									
HSE, CSR, Insurance	US$ '000	1,482	0.0	0.0	1,482				
Other	US$ '000	6,349	0.0	0.0	6,349				
Reserves	US$ '000	1.0 $/boepd	0.0	0.0	270	1,675	6,421	8,140	6,702
Total Other	US$ '000	**62,518**	**0**	**0**	**8,102**	**1,675**	**6,421**	**8,140**	**6,702**
Development Investment	US$ '000	**333,144**	**0**	**0**	**23,207**	**107,475**	**90,641**	**63,640**	**16,702**
Exploration Investment	US$ '000	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total (Full Year Guidance for 2017)	US$ '000	**333,144**	**0**	**0**	**23,207**	**107,475**	**90,641**	**63,640**	**16,702**
Capex per barrel of 2P Plus reserve		**8.4**							

Source: BGH analysis

Capital Budget CPR

Our budget is in line with the CPR's investment summary of a total of US$ 305 million. However, our budget is front-loaded due to the accelerated drilling campaign.

Investment Summary (in US$ '000): CPR, June 2018

	Well Count		Capital Investments (M$)			
Reserves Category/Year	Production	Water Disposal	EIA	Drilling	Facilities	Total
Proved						
2018	0	0	1,300.0	0.0	20,383.0	21,683.0
2019	1	1	700.0	26,675.7	18,980.5	46,356.2
2020	4	0	0.0	54,163.5	0.0	54,163.5
2021	2	0	0.0	26,687.6	42,075.0	68,762.6
Proved + Probable						
2018	0	0	1,300.0	0.0	20,383.0	21,683.0
2019	1	1	700.0	26,675.7	39,270.0	66,645.7
2020	4	0	0.0	54,163.5	0.0	54,163.5
2021	5	0	0.0	66,237.5	42,075.0	108,312.5
2022	0	1	0.0	10,280.0	0.0	10,280.0
2023	0	0	0.0	0.0	42,075.0	42,075.0
Proved + Probable + Possible						
2018	0	0	1,300.0	0.0	20,383.0	21,683.0
2019	1	1	700.0	26,675.7	39,270.0	66,645.7
2020	4	0	0.0	54,163.5	0.0	54,163.5
2021	5	0	0.0	66,237.5	42,075.0	108,312.5
2022	0	3	0.0	30,840.1	88,825.0	119,665.1
2023	1	0	0.0	14,613.7	0.0	14,613.7
2024	3	0	0.0	39,549.8	0.0	39,549.8
2025	2	0	0.0	24,936.2	0.0	24,936.2

Source: CPR 2018

Development Plan & Well Cost

In May 2019, PetroTal guides for a point-forward drilling budget of US$ 166m for the development of 2P reserves. Note that an average horizontal well costs $13m and takes 55 days to drill. Also note that so far, PetroTal completed all wells below budget.

Development Plan & Well Cost (in US$ '000)

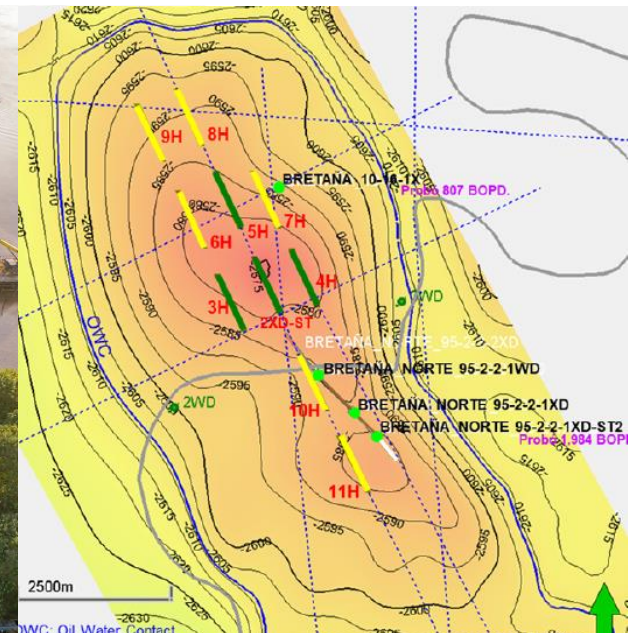
Need to Order				CSG, WH, 7" TBG, LH	WH, TBG, PKR, Perforations	Csg, WH, LH, Pkr	Csg, ESP, LH, AICD's	WH, Csg, Inject Pump, tbg	WH, Tbg, ESP,		
Have Ordered			Csg, Tbg, AICD	Csg , Tbg, AICD							
	2019										
	MOB	2XD - Dir Only	3H (500m)	2WD	WO 1WD (Converto to Prod)	4H (1000m)	ST 2XD H	3WD - CD	WO 1XD (ESP)		**Total**
Well Type	MOB	H	H	WD	WO	H	H	WD	WO		
Days	55	53	55	35	15	58	37	35	15		**358**
Cost $,000 MM	$4,700	$9,800	$13,200	$7,600	$1,500	$14,000	$8,700	$8,500	$1,500		**$69,500**
Wells Drilled		1	2	4		3	1st	5			**5**
Start Date	21-Dec-18	27-Feb-19	21-Apr-19	15-Jun-19	20-Jul-19	04-Aug-19	01-Oct-19	07-Nov-19	12-Dec-19	27-Dec-19	**27-Dec-19**

Need to Order	Tbg, ESP, LH, AICD, Csg, WS	WH, Csg, ESP, AICD's, LH	WH, Csg, ESP, AICD's, LH		WH, Csg, ESP, AICD's, LH	WH, Csg, ESP, AICD's, LH	WH, Csg, ESP, AICD's, LH	WH, Csg, ESP, AICD's, LH			
Have Ordered											
	2020										
	5H w/o Pilot 1000m	6H	7H	Build 4 Cellars & Pilot Supports	8H	9H	10H	11H			**Total**
Well Type	H	H	H	MOB	H	H	H	H			
Days	45	45	45	60	45	45	45	45			**330**
Cost $,000 MM	$13,000	$13,000	$13,000	$3,120	$13,000	$13,000	$13,000	$13,000			**$94,120**
Wells Drilled	6	7	8		9	10	11	12			**7**
Start Date	27-Dec-19	10-Feb-20	26-Mar-20	10-May-20	09-Jul-20	23-Aug-20	07-Oct-20	21-Nov-20	05-Jan-21	05-Jan-21	**05-Jan-21**

Single Pad Development

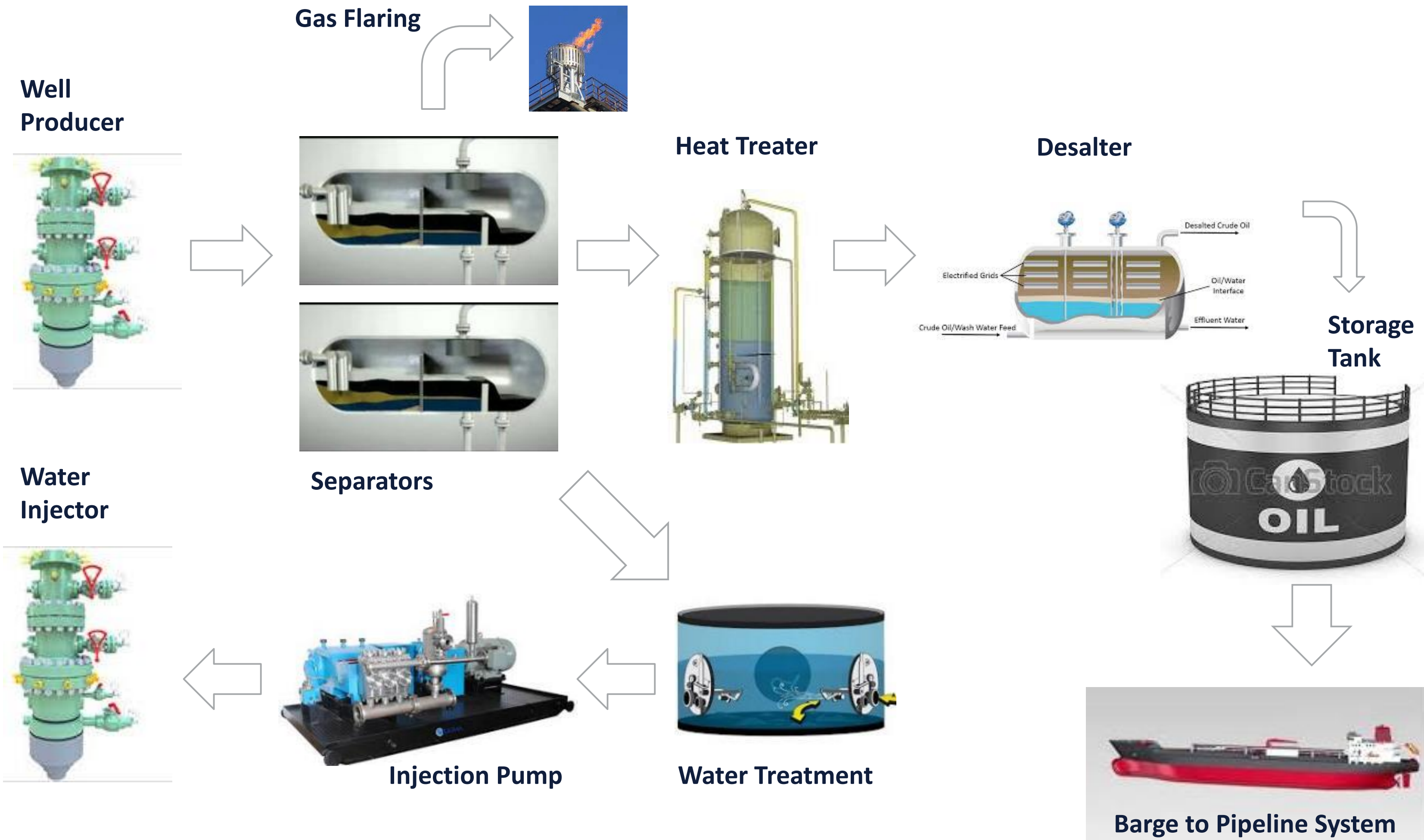
Bretaña is developed from one single location which is important due to the cost involved of developing one drilling pad.

Development from One Location



Process Facility Requirements

Bretaña is a “conventional” oil field which requires straightforward processing facilities. We assume a total facility budget of US$ 104m for the development of 2P reserves.

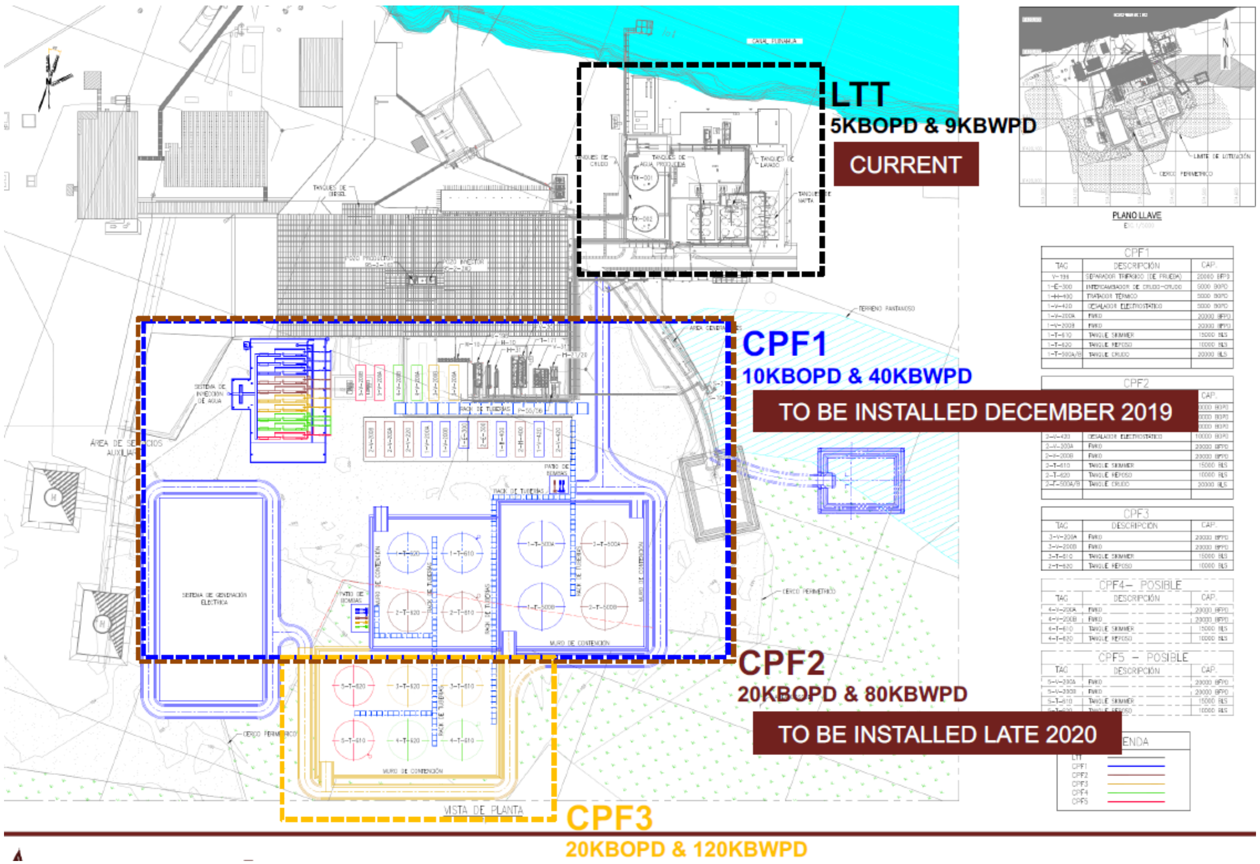


Source: PetroTal for BGH

Process Facility Development Phases

Today, the main bottleneck is water processing. Therefore, PetroTal is expanding its processing capacity in 2019/2020 to deal with up to 250,000 bpd of water production by 2023 as part of the 2P development plan.

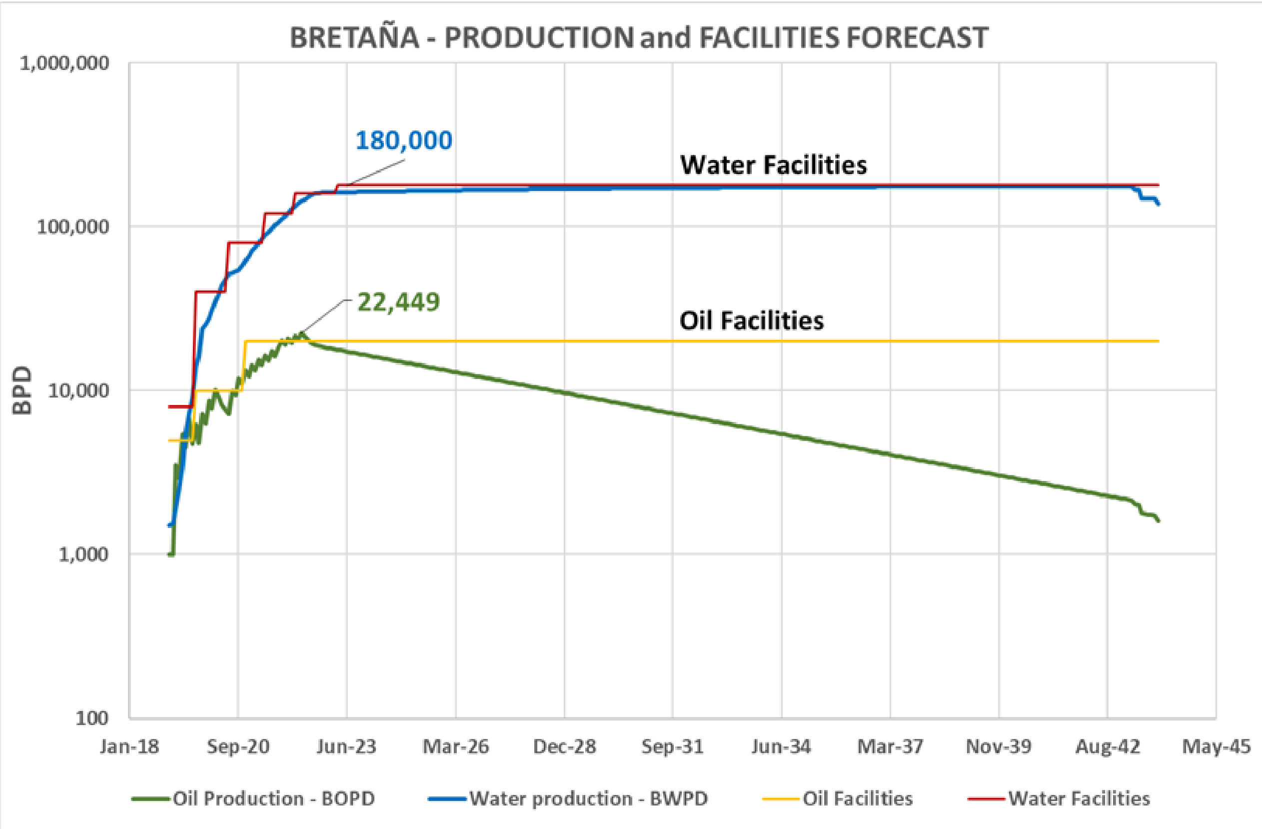
Platform Facilities and Equipment Plan to First Production



Capacity Forecast

PetroTal forecasts to have oil production facilities for a capacity of 25,000 bpd and water capacity for up to 180,000 bpd by 2023. This compares with our peak production rate of 26,153 bpd of oil in January 21 and a peak water production rate of 119,372 in 2025 for our 2P "Plus" model. Our 3P model would exceed the below capacity restrictions in 2021 and would thus need to be addressed by expanding the current oil storage facility of >20,000 bpd (see here page 10).

Capacity Forecast of Oil & Water Facilities (in barrels per day – bpd)



180,000 bpd

25,000 bpd

Source: PetroTal for BGH ; Note: the above peak production rate of 19,041 bpd is not the same as the annual average rate per day.

Trust – but Verify

Barge at Bretaña

Well 2-1 XD 2012

De-salter

«Site Visit»: The Burggraben Team

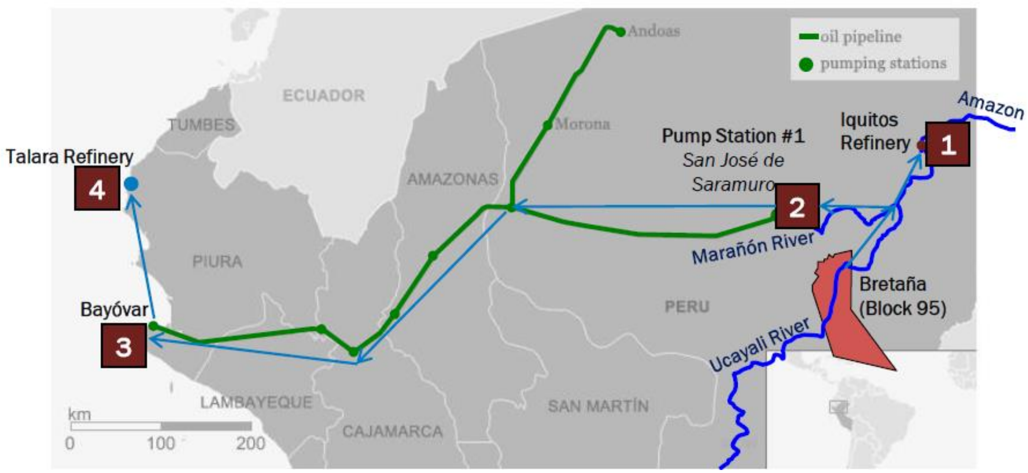
Source: BGH Site Visit October 2018

Transport

Transportation Routes

At full production, PetroTal is going to barge oil from Block 95 to Station 1 on the ONP Pipeline to transport it through the pipeline to the coastal Bayovar Terminal.

Transportation Routes



1 Initial 1,000 bopd being sold at Iquitos Refinery

2 With full production, barge oil north-then-west to Pump Station #1

3 Deliver oil to Bayóvar via Northern Oil Pipeline (200,000 bopd capacity / ~10% utilized) for marketing and sale

4 Bretaña crude oil will be processed at the Talara Refinery, whose ongoing expansion and upgrade is expected to be completed by late 2020

- During the initial months of production, PetroTal sold its production to the Iquitos Refinery in Iquitos. This did not require sending the oil through ONP pipelines.
- At full production, PetroTal is going to barge oil from Block 95 to Station 1 on the ONP Pipeline to transport it through the pipeline to the coastal Bayovar Terminal.
- Ample capacity exists within the pipeline system and barging oil in the Amazon River system has been a routine practice since the first fields were discovered in the 1970's.

Source: Company filings; Eight Capital

Barging Capacity

A barge can load up to 20,000 barrels. Bretaña can load two barges in parallel, with an hourly capacity of up to 3,000 barrels.

No Bottleneck

- Bretaña crude is collected from Bretaña by Petroperú and barged in double hull barges operated by a third party approx. 370km along the Ucayali River for a journey period of three days.
- Once the oil is loaded, revenues can be recognised and liabilities are transferred. Nevertheless, PetroTal is insured for a potential liability from a transport incident from which it may not be ringfenced.
- But note that oil sold to Petroperú is in transit for an average of up to 180 days and thus creates significant working capital needs to be financed, especially during 2020 and while PetroTal is ramping up production.
- Barges come in different sizes. The maximum capacity of a Amazonian barge is 20,000 barrels.
- Bretaña's loading station (see right hand side) has a nameplate capacity to pump up to 3,000 barrels per hour and can load two barges in parallel.
- We assume Bretaña to be able to comfortably handle up to 50,000 barrels per day of crude oil loadings and assuming no night shifts.
- In other words, loading capacity exceeds our forecast peak production month of about 18,500 barrels per day for the 2P reserve model.

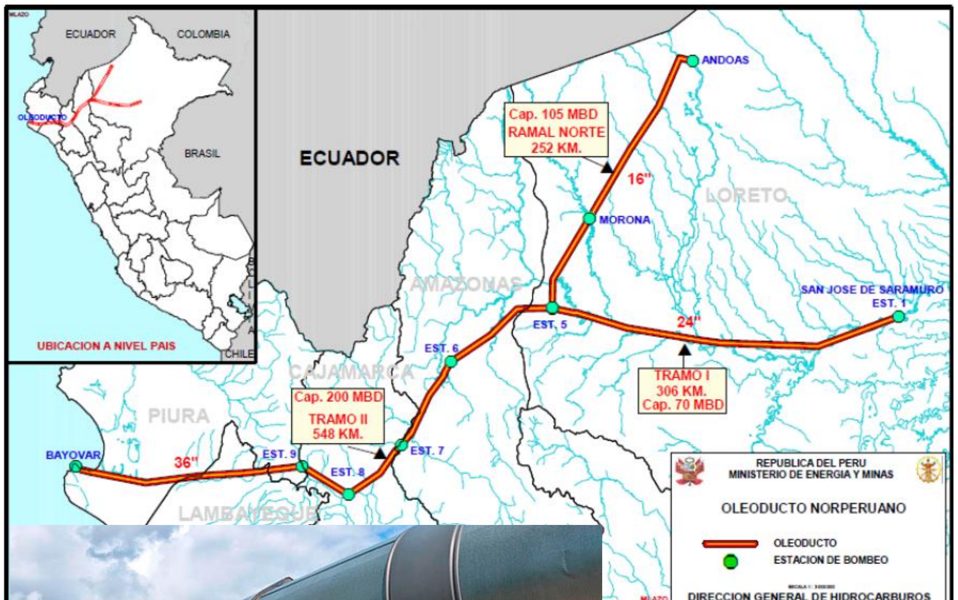
Barge Loading at Bretaña

Source: BGH analysis; Company filings; Picture by BGH

Pipeline System

Peru has ample idle pipeline capacity for PetroTal's production. However, in recent history the uptime record was below average.

Pipeline System



- Construction:
  - Construction of the southern leg of the Oleoducto Nor Peruano (ONP) pipeline began in 1976 and first oil was shipped from the Block 8 fields to the coastal Bayovar Terminal in May 1977.
  - In February 1978, the Oleoducto Ramal Norte (ORN) was commissioned to transport oil from the Block 192 fields to the Bayovar Terminal.
- Capacity:
  - Design capacity of the system is up to 200,000 bpd (105,000 for ORN, 70,000 bpd for ONP and 200,000 bpd from Station 5 to the Bayovar Terminal),
  - With the decline of the Block 8 and 192 fields, throughput has fallen to less than 10% of that.
- Interruptions:
  - In August 2016 and following a series of reported spills, the Peruvian government ordered the closure of the pipeline for six months to conduct assessments and remedial work.
  - Community issues in and around Block 192 have caused additional disruptions to the ORN Pipeline in October-November 2017.
  - According to the Perupetro website, both pipelines were transporting oil in 2018 but do not possess exact uptime statistics.
  - We understand that Petroperu is undertaking works to keep the pipeline operating and is about to finish the design and cost studies to begin the modernization of the pipeline.

Source: Ministerio de Energia y Minas, www.perupetro; Note: bpd = barrels per day

Transportation Cost

Over the life of the field, we assume transport cost of $13/bbl, of which $9/bbl are for pipeline tariffs and the remaining for barging.

Barging & Pipeline Cost

- Barge tariffs stand at US$ 5.5/bbl in 2018 for transport of relatively small volumes of oil produced from the initial production well to the nearby Iquitos refinery. Barging cost are likely to reduce to US$ 3.5/bbl due to bigger loadings and higher volumes.
- On 29 May 2019, PetroTal signed a contract with Petroperú, the State owned oil company, who operates the North Peruvian Pipeline (“ONP”) to deliver oil to the Pacific coast via the pipeline.
- PetroTal currently sends oil to multiple markets via barges and trucks, however the use of the pipeline mitigates potential production constraints. The Company plans to access the ONP once it reaches 5,000 barrels of oil per day (“BOPD”) by mid year.
- The exact terms remain undisclosed but we assume pipeline cost to be US$ 9/bbl after consulting with management and Perupetro (site visit in October 2018). However, it is reasonable to expect pipeline tariffs could fall as volumes increase.
- The then President of Petroperú Mr. James Atkins Lerggios has stated publicly in 2018 that the pipeline tariff could fall to US$ 3.0-3.5/bbl. Neither an associated throughput volume, nor a target date was, however, provided to us.
- PetroTal management estimates, through analysis of historical tariffs, that this could be achieved if pipeline throughput increases from current levels of around 17,000 bpd to around 50,000 bpd.
- One potential area of uncertainty relates to the pipeline operator’s plans to upgrade the pipeline in future. Upgrade investments will need to be recovered through future tariff payments.
- This raises the potential for tariffs to be higher in future than historical levels, at a given throughput rate. A potential pipeline tariff of US$ 3.0-3.5/bbl at throughput rates of 50,000 bpd provides for such an outcome, since historical tariffs fell to US$ 2/bbl at a throughput of 40,000 bpd.

Source: BGH anaylsis; Note: Mr James Atkins Lerggios has past away in 2019.

Osheki Prospect

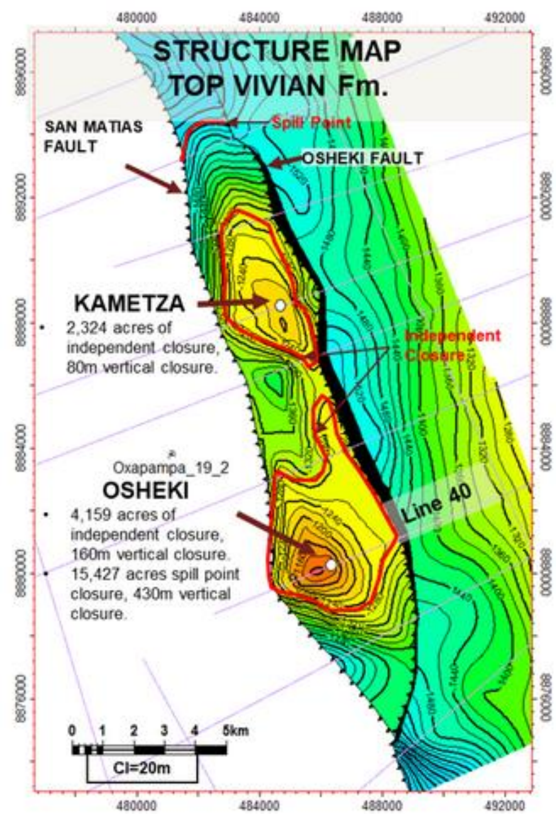
Osheki Prospect

We do not have sufficient information to judge the Osheki prospect as of today. However, we assume active Latin American IOCs such as Shell, Repsol or Hunt to engage in the ongoing farmout process managed by GMP, an oil & gas broker in London.

Block 107 – Osheki Prospect

- The Osheki Structure is a sub-thrust play similar to the Cusiana complex in the Llanos Foothills of Colombia;
- PetroTal was assigned a mean estimate unrisked prospective resources of 534m barrels of oil (which is huge);
- 2-D seismic completed with drilling permits approved;
- De-risked with new 3D Geologic Model supporting Cretaceous reservoirs with oil charge from high quality Permian source rocks;
- **Exploration Strategy by PetroTal**
  - Farm out process commenced in October 2018; Note that we spoke with GMP about the process but are unable to judge it at this stage!
  - Targeting first exploration well in late 2019 / early 2020;
- **Valuation:**
  - We assign little value to Osheki at this point as we do not have sufficient information to value the prospect.
  - Assuming an NPV of $1.5 per for the 534 MMbbl resource and assigning a chance of success of 5%, we derive US$ 53m value.
  - This stands against a book value of US$ 4.7m as at 31 December 2018 for Block 107.

Structure Map Top Vivian Formation



 Source: PetroTal

Risks

Key Risks & Message

PetroTal is all about operational execution. Our due diligence over the past 12 months allowed us to "de-risk" the technical concerns around the reservoir while we are convinced that Manolo and his team will deliver the development plan safely, on time and on budget.

The Two Most Important Risks are Liquidity and Execution

- Liquidity Risk from Lower Oil Price:
  - Like all E&P companies, PetroTal is exposed to the vagaries of the international crude oil market. But note that short term price collapses in oil prices tends to "self-heal" from "shut-in" production and "sticky" demand at lower prices. Lower oil prices can also be mitigated at company level through an annual hedging program once volume is developed and certain.
  - During PetroTal's development phase however, its cash flow profile can be significantly impacted from a collapse in oil prices to below, say, $55 Brent. If unhedged against lower oil prices as today, PetroTal will have to be able to access debt (i.e. a working capital facility) or equity financing to bridge any shortfall in liquidity or will have to restrict its drilling campaign. The latter will cause additional costs, among others, from mobilising the rig back on site at a later stage and is more than suboptimal. But as we described above, PetroTal is in a comfortable position to access a working capital position today, although that is not yet in place.
- Operational Risks: The second main risk is execution. The company will bring relevant amounts of oil from Block 95 into the oil & gas network of Peru, from a remote area and with every day production or transport risk. However, such risks are not binary. PetroTal delivered the most important permit for a full field development in May 2019. Now, it will have to deal with safe operations like any other E&P worldwide. Likewise, it will have to remain agile to address potential new downtime at the pipeline due to spills, attacks or due to renovation or reconstruction. We are convinced the competent management team will deliver just that.
- On the following pages, we will address certain other risks in more detail.
- For a full risk assessment, please refers to the company's November 2018 Admission Document: http://petrotal-corp.com/investor-relations/aim-rule-26/#admission-doc

Source: BGH analysis

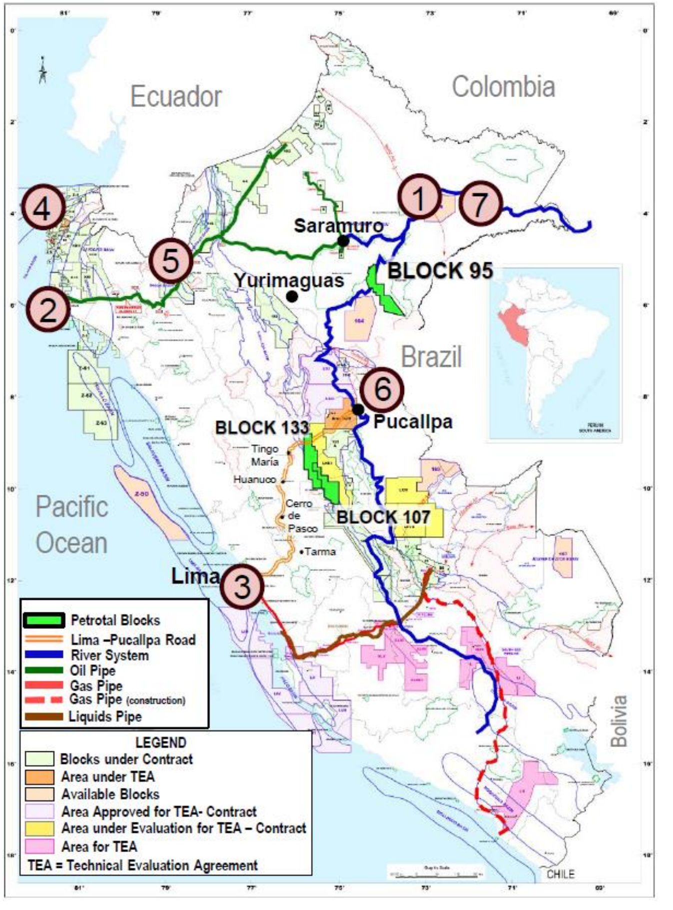
Risk of Interruption in Oil Transportation

In our view, the main risk for an ongoing and smooth operation is transportation related, that being mainly pipeline downtime. However, PetroTal does have significant optionality…

Assessment

1. **Iquitos Refinery (1,200 bopd):** barging distance of 370km. Delivery: 3 days.
2. **Boyovar Port (20,000 bopd, to reach Talara and La Pampilla Refinery in Lima or export internationally):**
    a. Barging 460km to Saramuro, 856Km through the Peruvian Northern Pipeline (ONP) to Bayovar Port. Delivery: 4 days.
    b. Barging 740km to Yurimaguas and trucking 940Km to Bayovar Port. Delivery: 10 days.
3. **Conchan Refinery in Lima (1,500 bopd):** barging 700km to Pucallpa and trucking 750km to Lima. Delivery: 10 days.
4. **Talara Refinery (20,000 bopd)**: barging 460km to Saramuro, 856km through the Peruvian Northern Pipeline (ONP) to Bayovar Port. Then trucking or barging to Talara Refinery. Ideal market after modernization project is complete at the end of 2020.
5. **El Milagro Refinery (1,500 bopd)**: barging distance of 740km to Yurimaguas port and trucking 540km. Delivery: 8 days.
6. **Pucallpa Refinery (2,500 bopd):** barging 700km to Pucallpa. Delivery: 7 days.
7. **Exports via Perenco's Manati FSO (20,000 bopd):** barging 500km. Delivery: 5 days.

Transport Routes



Source: PetroTal, May 2019

Development Risk

The development of the Bretaña field with 11 producing wells will inevitably require the PetroTal team to solve issues. But such issues do not mean not to deliver the oil on time and budget. Rather, they can be addressed in real-time and a resourceful manner.

Operational Update: 18 June 2019

- Developing a field with 11 producing wells of $13 million each over approx. 800 days will not go in a straight line.
- On 18 June 2019, PetroTal made the following announcement, which serves as a gentle reminder of the development risks of a 24 months drilling campaign:
  - *"The Company's third oil well, which reached total depth in early June, was completed as an oil producer in the Vivian formation in the northern portion of the Bretaña structure. The well was brought online at an initial rate of approximately 3,500 BOPD."*
  - *"This is an early production rate and more detailed production data will be announced in due course. The well has an electric submersible pump ("ESP") that will optimize future well productivity. The well, which originally scheduled to be completed horizontally, was brought online through a deviated completion.* ***While drilling the section above the target Vivian formation, the service provider's directional drilling tools, needed to drill the horizontal section, had a mechanical failure that resulted in the need to sidetrack the well and complete it directionally****. Even with the sidetrack, the well is expected to come in under the estimated US$13 million pre-drill budget."*
  - Manolo went on the explain: *"The BN 95-3D well came online at impressive rates, and although in its early days, is producing 3,500 BOPD. The team made a decision to complete the well vertically and deliver key cash flow, knowing that we can sidetrack the well into a horizontal completion at a later date, likely in 2020."*
- The key takeaway here is not that "things can go wrong" when drilling a well of 3,5km over 55 days with a crew of 200 people in the middle of the Amazonian. The key takeaway is that "things will go wrong" and success means to have an agile management team that is able to address the issue in real-time and find a smart work-around to issues encountered.
- Manolo did just that. He and his team decided to get the well online vertically for now and come back to complete the job when time permits in 2020. This will also allow the team to resolve any potential commercial disputes with the drilling contractor.

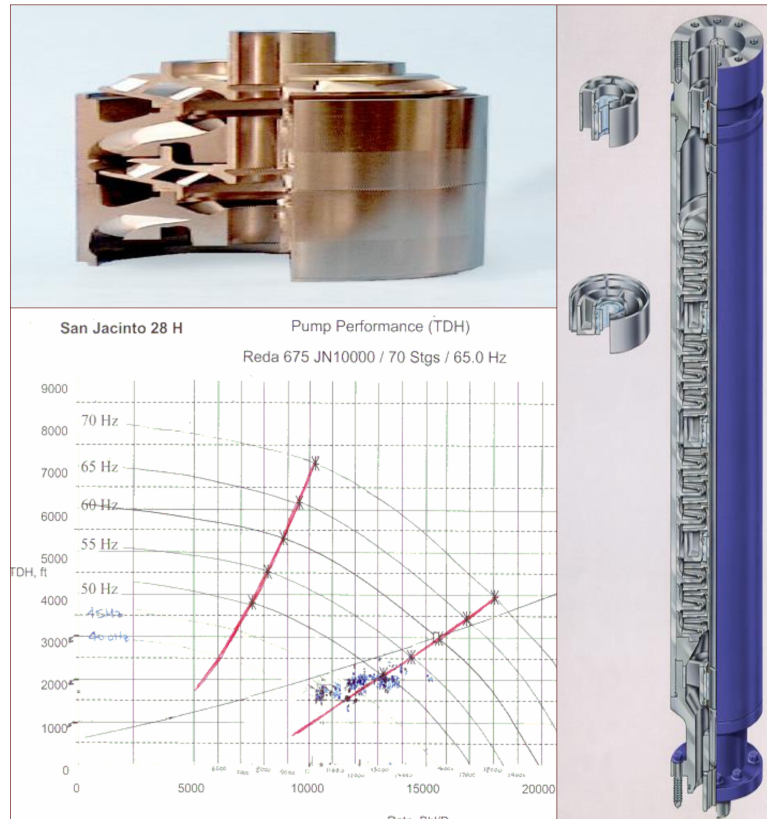
Source: BGH analysis; Company filings; Note: BOPD = barrels of oil per day

Risk of Operational Downtime

One major cause of downtime in Peru's heavy oil fields were failures of Electrical Submersible Pumps (ESP). However, such downtime can be prevented...

ESP Lesson from Field 1AB in Peru

- Heavy oil fields use an electric downhole pump (ESP) for increased production rates. They are designed with vane & fin configurations to accommodate frictional losses and pump efficiencies, caused by heavy oil viscosity.
- Conventional ESPs often incurred failures due to equipment tear down in Peru heavy fields.
- The root failure analysis was a key process to identify the cause of failures and to recommend the modifications that need to be done.
- In the case of Block 1AB, the main cause of ESP failures was mechanical vibration. Efforts to minimize vibration, such as the use of compression pumps was the solution for this problem.
- Once addressed, the average run life of ESP installations in Block 1AB increased from about 1 month (1981) to 31 months (2006).
- Currently 20 % of ESP assemblies are running for more than 5 years. Some of them exceeding P10 years of continuous operation.
- Increased run lives play a crucial role in the reduction of the lifting cost, the control of deferred production and workover spending.
- We are convinced that PetroTal's local management team (which we visited) has the knowledge and experience that will help maintain or improve the life of the ESPs in BLOCK 95.



 Source: BGH analysis

Conflict Risk with Local Community

While the Bretaña field is located in a “friendly” part of the Amazonian region, we expect PetroTal’s management having to deal with indigenous issues regularly.

Community Context

- On 25 March 2019, PetroTal was part of a conflict with local residents as those were promised, but not paid, certain government salaries. The conflict had nothing to do with PetroTal’s Bretaña operation.
- Regardless, locals from the Bretaña village seized the oil installation operated by PetroTal to demand electricity and other government services. Production from PetroTal's Block 95 halted for several hours until it was re-continued.
- The latest protest to target oil and mining operations in Peru in recent months has sparked calls for the government of President Martin Vizcarra to take steps to prevent the incidents, which risk deterring investment in the country.

- **Community Context**:
  - The Bretaña field is located in the Amazonas basin (Block 95). The terrain is flat and is flooded half-yearly as a result of the river overflows during the rain season.
  - The base camp is near the town of Bretaña of the Puinahua District, opposite the Pacaya Samiria National Reserve. The Bretaña town has a population of about 2,000 people (indeginous).
  - The Puinahua District consists of 18 villages. Its population comes from old Cocamilla Cocarna families and migrants from other parts of the Amazon. Their main activity is fishing, agriculture and trading of local products.
  - The villages have no drinking water nor electricity. Rain or river water are collected for human consumption. Almost all areas of the district are connected by a rural telephone service. School and health facilities are precarious. In terms of wellbeing, the region presents the worst statistics at national level.

Source: BGH analysis; Company filings

Commodity Price Risk

- It is not part of this presentation to discuss our commodity price outlook for crude oil in detail;
- However, in May 2018 we published our long-term assessment of oil prices here: https://seekingalpha.com/article/4170446-crude-oil-ready-triple-digit-oil-prices
- Clients of Burggraben may ask for a detailed up-to-date assessments for either of the two commodities at office@burggraben.ch
- If you want to become a client of Burggraben, please send an Email to alexander.stahel@burggraben.ch

Source: BGH analysis

Appendix

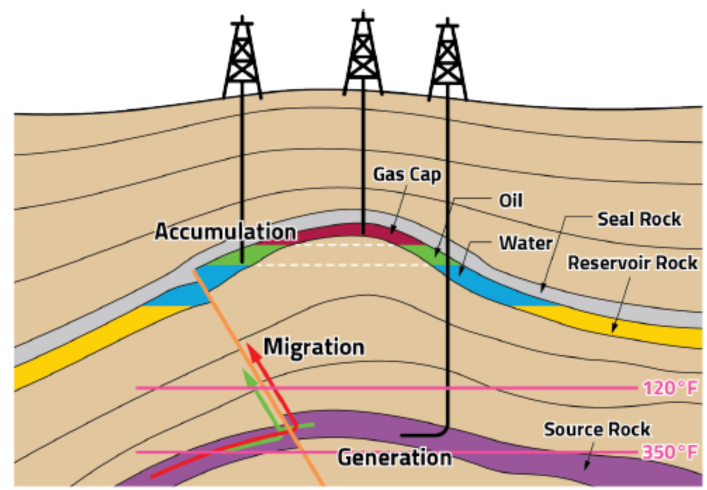
Petroleum System Basics

Conventional Petroleum Systems are much cheaper to produce than unconventional systems such as US Shale as the latter require significant stimulation for the oil to move.

Petroleum System Elements

1. **Source** – hydrocarbons originate from prehistoric planktonic organic and plant matter contained in sedimentary rocks buried at sufficient depth to be in the hydrocarbon generation window (a.k.a. "kitchen'')
2. **Migration** – pathways for the hydrocarbons to move from source to reservoir
3. **Reservoir** – a rock where oil and gas accumulates
   - Storage = porosity = space between the rock grains
   - Flow capacity = permeability = connected rock pores allow hydrocarbons to move
4. **Trap** – structural and stratigraphic closures where hydrocarbons buoyantly collect
5. **Seal** – an impermeable cap over the trap, usually clay-rich shale rock

- **Conventional Play**
  - 1 to 5 independent
- **Unconventional Play**
  - 1 = 3 = 4 = 5
  - No migration, stays "at source''

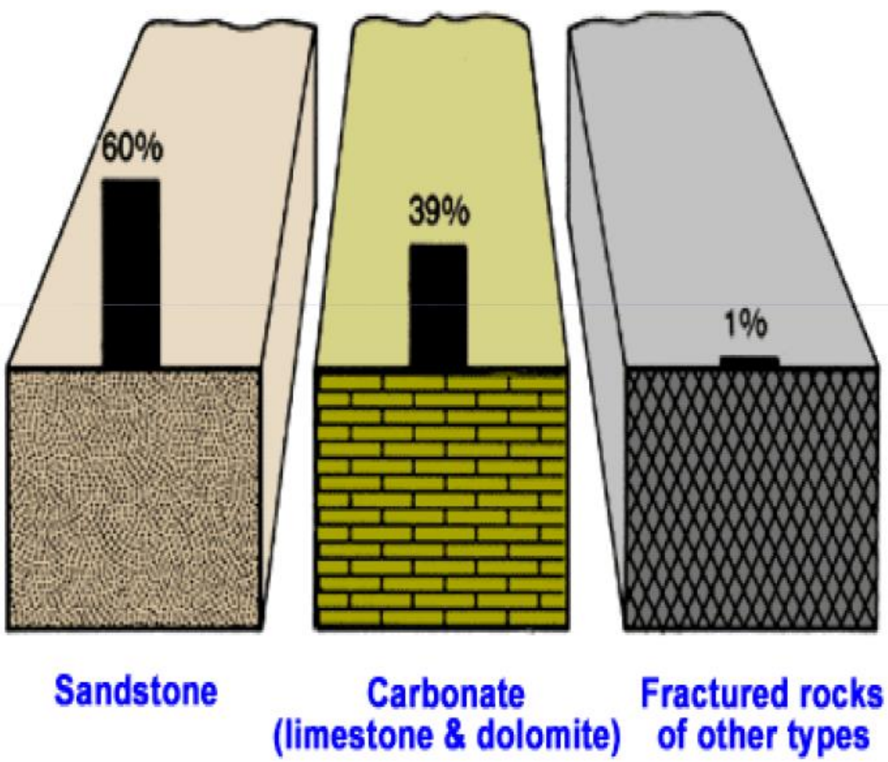


 Source: RS Energy

Organic Matter & Reservoir Rock

The most common reservoir rocks are sandstone and carbonates.

Most Common Reservoir (not Source) Rock Types



Description

- When an organism (plant or animal) dies, it is normally oxidized. Under exceptional conditions: organic matter is buried and preserved in sediments
- The composition of the organic matter strongly influences whether the organic matter can produce coal, oil or gas.
- A reservoir rock is that kind of rock which can hold the hydrocarbons. Most common examples of reservoir rocks are sandstone and Carbonates (limestone and dolomite).

Dolomite

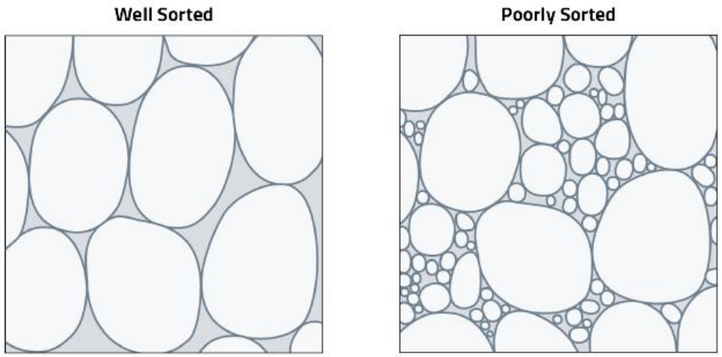
Source: https://www.slideshare.net/petroshahnawaz/basics-of-petroleum-geology?from_action=save

Porosity & Permeability

How much oil & gas can be recovered from a reservoir with Original Oil In Place (OOIP) will largely depend on its porosity & permeability.

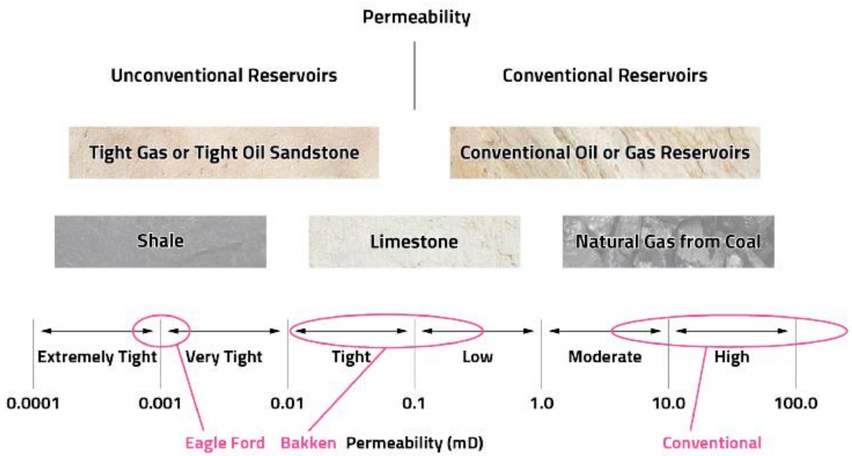
Porosity (storage space for hydrocarbons – a rock sponge) and Permeability (flow)

- **Porosity (Φ)**
  - Space between rock grains filled with oil, gas and / or water
  - Stated as a percentage of the gross rock volume commonly 3 – 30%
- **Permeability (k)**
  - Conductance (resistance) to flow
    - Larger number = increased flow
  - Pore throat size and tortuosity
  - Typically measured in millidarcies (md) conventionally, nanodarcies unconventionally



D'Arcy's Law

$$Rate = Permeability\ X\ Pressure\ Gradient \div Viscosity$$



Source: RS Energy

Gross versus Net «Pay»

Net Pay describes the economically producible hydrocarbon thickness of a reservoir.

Description of «Pay»

- Pay is a terminus technicus used in the industry to describe the part or portion of a reservoir that contains **economically** producible hydrocarbons.
- The term derives from the fact that it is capable of "paying" an income. Pay is also called pay sand or pay zone;
- The overall interval in which pay sections occur is the gross pay;
- the smaller portions of the gross pay that meet local criteria for pay (such as minimum porosity, permeability and hydrocarbon saturation) are net pay.
- The goal of the net-pay calculations is to eliminate nonproductive rock intervals and to provide a solid basis for a quality 3D reservoir description and quantitative Original Oil in Place (OOIP) and flow calculations from these calculations at the various wellbores;

Net versus Gross Pay Thickness

Source: Schlumberger; www

Conventional Exploration Risk

The key risk for a conventional field is the seal. A leak will drain a reservoir over millions of years and can only be tested by drilling.

Reservoir Risk (below ground)

- **Chance of Technical Success =**
  - Chance of (Source X Migration X Reservoir X Trap X Seal)
- **Risked NPV =**
  - Chance of Technical Success X Unrisked Project NPV
- **Risked NPV > Cost**
- Numerous methods to "improve" or better quantify odds – Monte Carlo simulation, gather more data
- **Practically, risking used to rank prospects**
- **Key risk is the seal** – a leak will drain a reservoir over millions of years and can only be tested by drilling!