West African Offshore Exploration

In the context of the deepwater versus US shale debate

June 2018

Contents: Shale and deepwater

Key thoughts and takeaways

- **Why invest in exploration:** uncorrelated returns to the market (which is what portfolio managers look for); potential for 10x or more uplift in value which isn't available elsewhere; exploration costs have fallen dramatically improving the economics; no cost inflation evident yet (unlike US shale) – BP believes 75% of savings are sustainable; development costs and time have been reduced - improving the economics (e.g. Liza in Guyana). Integrateds are realising they need to replenish inventory (e.g. TOTAL, Exxon) meaning transactions are likely to return. Long-dated Brent is trading at ~$65/bbl giving an average IRR at FID of ~23% on a West African deep-water development. Long-dated WTI is trading at >$10/bbl discount to Brent – this for example would reduce the Permian IRR to 26% versus 43% at a $0/bbl discount to Brent. Liza (Guyana) and Lula (Brazil) are examples of the huge value creation that is possible through frontier exploration, which isn't obtainable through shale.
- **What are the impediments to investment into exploration:** It is still possible (based on recent deals/equity market valuations) to buy oily resource at a discount to where finding costs have been in recent years. Even in exploration success cases (e.g. SNE in Senegal) the upside hasn't been huge. It is more of a struggle to obtain funding for international developments than US shale given the much bigger liquidity pool in the US. There remains the perception of risk post discovery in the appraisal (e.g. Paon) and development phases (50% of fields not producing to expectations according to one study). Political risk remains very much on investors' minds as does corporate governance and the idea of "lifestyle" E&P companies listed on AIM. Another issue is that the long-dated nature of these projects means that investors are worried about the cashflows only being generated after the world has reached peak oil demand.
- **Shale versus deepwater:** US onshore has a higher IRR but a lower NPV10 than W. African developments. At $60/bbl Brent: To get to the same NPV/bbl for the average W. African development implies around a 3% higher discount rate. So the Permian at a 10% discount rate has the same NPV as W. African average at a 13% discount rate. Permian should attract a lower discount rate due to lower perceived geological risk and lower country risk. However risks still remain on shale (many areas of potential bottlenecks increasing costs), there is a limited opportunity set, despite all the hype there haven't been acceptable returns generated and it appears that we are reaching a plateau in productivity and efficiency gains. Also there are risks that production may underwhelm on issues such as rising GORs and interference between wells.

Deepwater developments considerations

- Exploration costs
  - Cost of licence acquisition
  - Cost of exploration
  - Cost of appraisal
- Time
  - Time to explore
  - Time to appraise
  - Time to develop
- Fiscal terms
  - Type of contract: PSC or Tax and Royalty
  - Tax losses/ability to pool across developments
- Cost of development
  - Quality of the resource
  - Local content rules
  - Amount of leased versus purchased equipment
  - Phasing of development
  - Cost recovery
  - Decommissioning cost
  - Inflation/deflation
- Monetisation
  - Oil quality and price realisation
  - Gas monetisation options
- Funding
  - Cost of capital
  - Farm-outs and asset sales
  - Equity
- Risk
  - Exploration risk
  - Appraisal risk
  - Development risk
  - Political risk
  - Spillage risk
  - Tax (e.g. CGT or tax changes)
  - Production disappointment
- Upside
  - Follow-on exploration in acreage
  - Improved recovery factors and reserves
  - Ability to leverage infrastructure

Exploration or acquisition of resource

- **Lower costs of obtaining exploration acreage and drilling the wells creates a better value proposition and also gives investors exposure to uncorrelated returns that aren't available from US E&Ps. Exploration success rates should improve as operators are now more capital disciplined forcing them to only drill their best wells.**

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"First look at the size of the prize and then the risk involved - Geology first, Economics second" R.E.Mcgill

Source: Akap Energy

Buying versus exploring for resource

- Another argument against exploration is that you can buy discovered resource cheaper, which is apparent when you see many companies still trading at very low $/bbl valuations.
- Outside of the US, with the exception of maybe Norway, there has not been a lot of liquidity for sellers that are trying to monetise discovered resource, given a limited buyer set. Looking at the main African deals over the last few years the average price paid was $1.8/boe of pre-FID resource.
- Cobalt, the most successful explorer in Angola struggled to sell its oil discoveries and agreed a deal (which fell through) with Sonangol for <$3/boe, which is less than it invested. It was eventually forced to sell for $1/boe last year.
- In the past, one of the downsides of paying up for exploration was that you would expect the key exploration personnel to leave and start their own independent E&P once again. However in this market we think that is unlikely to happen so an integrated would get the opportunity to high grade its exploration team by buying one with a good track record (the BP-Kosmos deal in Mauritania / Senegal is a good example).

Recent African deals for pre-FID resource

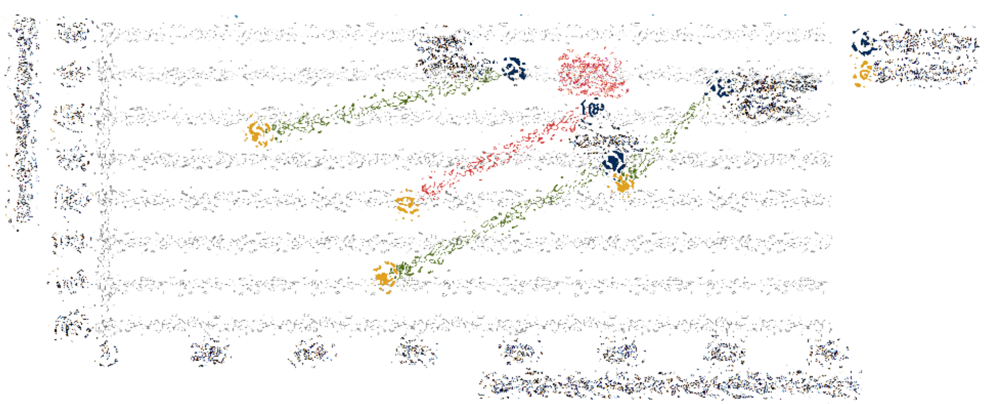
Asset	Main region	Buyer	Seller	Date announced	Price paid ($mn)	2P+2C net (reserves) (mmboe)	$/boe
Lokichar Basin	Kenya	Maersk	Africa Oil	09-Nov-15	$640	290	2.2
SNE	Senegal	Woodside	Conoco	14-Jul-16	$442	196	2.3
Fortuna	Equatorial Guinea	SLB/Golar	Ophir	10-Nov-16	$305	232	1.3
Tortue	W. Africa	BP	Kosmos	19-Dec-16	$916	1175	0.8
Dussafu	Gabon	BW Offshore	Harvest	22-Dec-16	$32	20	1.6
Lake Albert	Uganda	TOTAL	Tullow	09-Jan-17	$900	367	2.5
Area 4	Mozambique	Exxon	Eni	10-Mar-17	$2,800	2500	1.1
Block 20/21	Angola	Sonangol	Cobalt	19-Dec-17	$500	500	1.0
Tano Cape Three Points	Ghana	Aker Energy	Hess	19-Feb-18	$100	275	0.4

Source: Akap Energy

Impact of time: development

- The bottom left chart shows how time to market has been shrinking for new developments but so has the size given smaller discoveries and phasing of developments.
- The right hand chart shows some recent and pending developments and the wide variety of cycle times from discovery to first oil.
- On the next page the cycle time for West African projects from licence award to first oil are show for developments on-stream in 2014 or earlier.

Average size of resources sanctioned and time to market



Comparison of key fiscal terms

Fiscal terms and valuation metrics for West African countries and US at $60/bbl Brent

	Government take	NPV/bbl	IRR	PSC or T/R	Royalty	Contractor share of profit oil	Corporate tax rate	Other
Angola	65%	$2.78	19%	PSC	0%	10-70%	50%	
Cameroon	61%	$3.25	20%	PSC	0%	35-85%	38.5-50%	
Congo	49%	$3.68	19%	PSC	15%	60%	0%	Further oil price based tax
Cote d'Ivoire	52%	$4.26	22%	PSC	0%	47-62%	25%	
Gabon	55%	$3.67	20%	PSC	4.5-11%	25-50%	0%	
Gambia	52%	$3.82	20%	T&R	12.5%	N/A	41%	
Ghana	46%	$4.81	22%	T&R	5%	N/A	35%	IRR based additional tax
Guinea Bissau	59%	$3.30	20%	PSC	3%	45%	25%	
Mauritania	51%	$4.12	21%	PSC	0%	58-69%	27%	
Morocco	18%	$8.27	29%	T&R	7%	N/A	30%	0% tax for 10 years
Namibia	52%	$4.35	23%	T&R	5%	N/A	35%	APT of 25% over 15% IRR
Nigeria	73%	$2.12	18%	PSC	12%	25-70%	52%	
SA	35%	$3.03	19%	T&R	6.5%	N/A	28%	
Senegal	59%	$6.05	25%	PSC	0%	46-65%	25%	
US	56%	$2.65	26%	T&R	32.5%	N/A	21%	
West Africa avg.	52%	$4.11	21%					
PSC avg.	58%	$3.69	20%					
Tax avg.	41%	$4.86	23%					

Source: Akap Energy

Cost of development

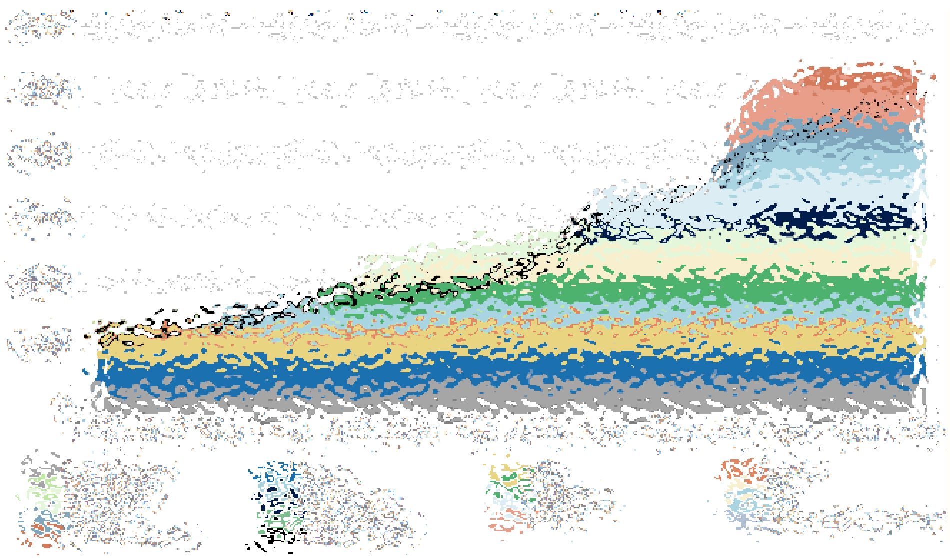
- **The quality of the resource is still a big factor in determining costs. Development costs have come down through a combination of lower service costs, simpler/phased developments and standardisation. Cost inflation is unlikely to rear its head soon offshore but we are starting to see it already US onshore**

Source: Akap Energy

US crude differentials

- A big issue in the Permian basin in the US is getting your hydrocarbons to a delivery point. If capacity is tight, wide discounts are realised. For example the WTI Midland differential to Brent settled was $18/bbl in early May.
- As production grows beyond the capacity of existing pipeline infrastructure, producers must use more expensive forms of transportation, including rail and trucks.
- Also given a lack of refinery processing capacity and infrastructure at US export terminals, WTI price differentials at Cushing have been under pressure.
- There are also risks that if there isn't enough gas take-away capacity that wells will have to be shut in as it is not possible to flare the gas.

Permian production vs out-of-basin take-away capacity kbbl/d

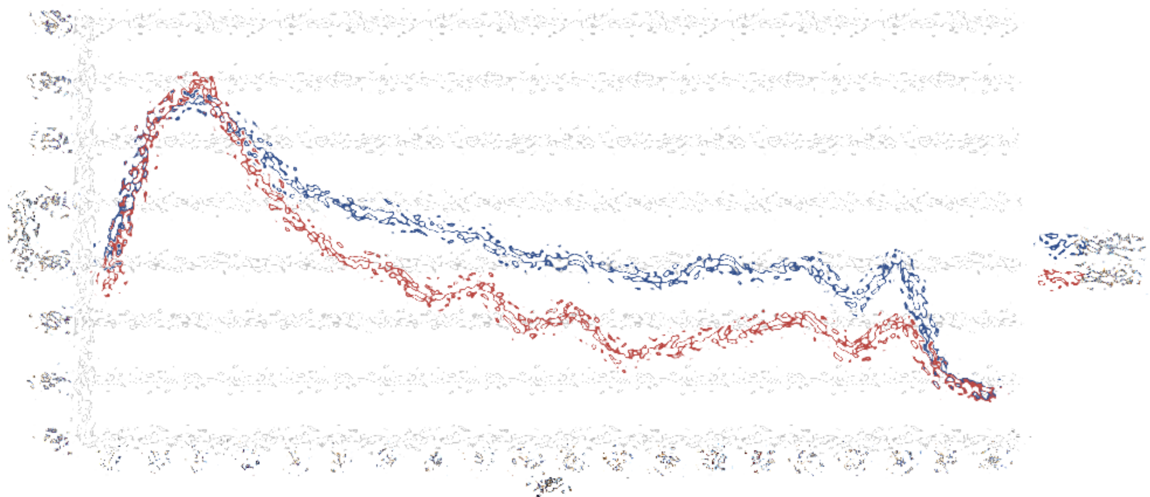


US crude oil spot price differentials to Brent ($/bbl)

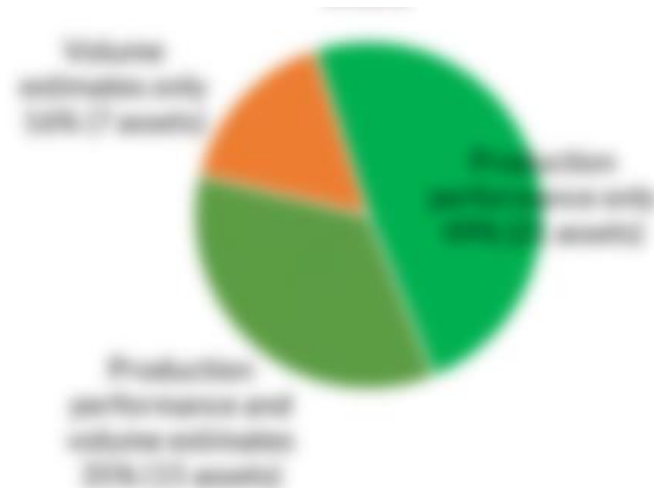
Risks

- **Production disappointment**: Another under-estimated risk is that once a field comes on production, it doesn't produce at the expected rates. Analysis has shown that major projects on average only produce at ~60% of design capacity at peak. This can be for a variety of reasons such as discovering that a reservoir is compartmentalised (e.g. Chinguetti), issues with the completion techniques used in the wells (e.g. Jubilee), early water break through, corrosion and mechanical failures.
- Half of oil and gas fields are not producing to expectations when onstream, and a new Westwood study shows that this is mainly due to unexpected reservoir issues. 70% of the fields studied with limited appraisal were found not to perform to the development plan.
- The most common causes of non-performance were: inaccurate prediction of in-place hydrocarbon volumes (48%), inaccurate prediction of pressure support due to misdiagnosed connectivity between producers and the water injections or water-leg (42%), and different reservoir quality than predicted (38%).

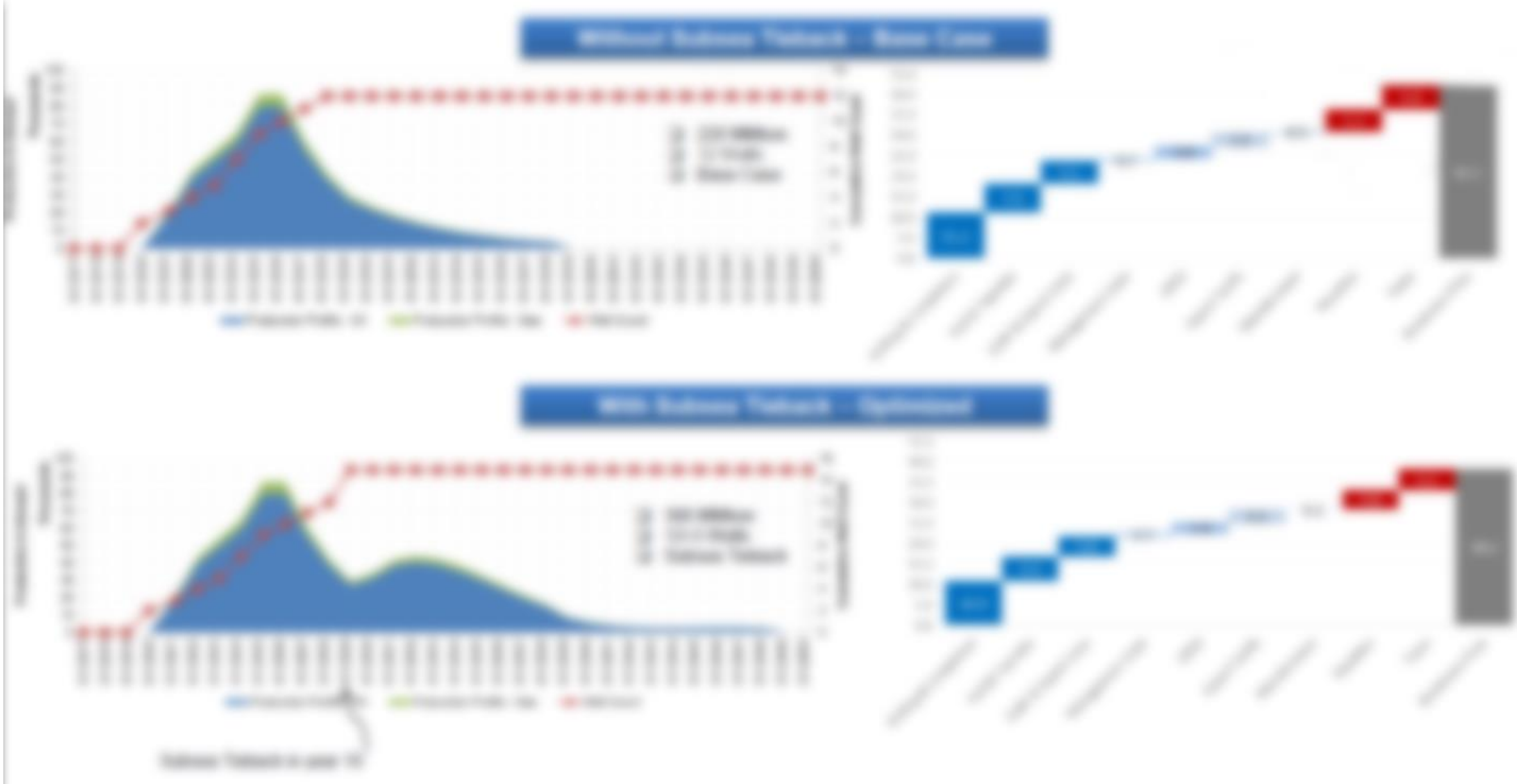
Project performance as a percentage of design capacity by year after start-up



Frequency of production performance and volume estimates issues



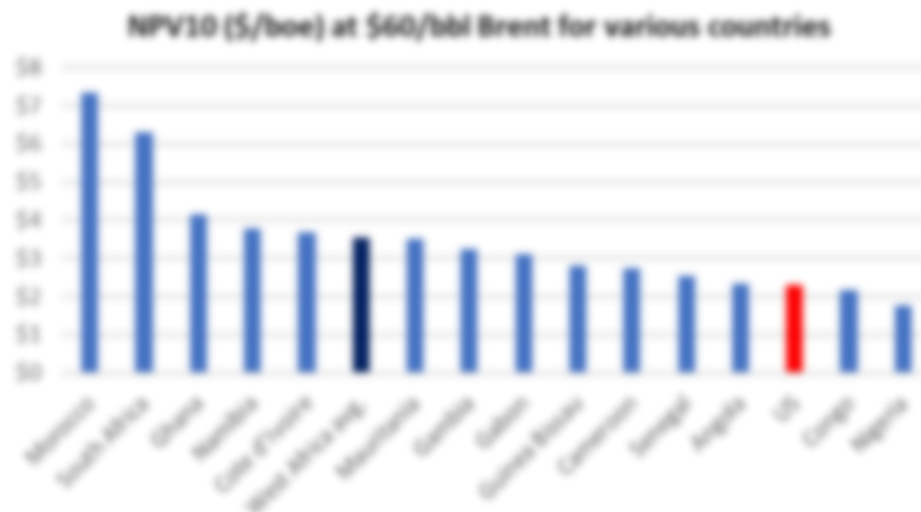
Subsea tie-back reducing break-even



NPV for a generic development

- We have tried to compare deepwater developments in West Africa, using all the same assumptions and only varying the fiscal terms to see how the countries stack up from a profitability standpoint relative to each other.
- The full set of assumptions is in the appendix but the main ones are developing a 500mmboe field (90% oil) at $60/bbl Brent, with $10/boe capex and $10/boe opex.
- We have also included a similar sized Permian development into the mix with similar assumptions. We have taken one of the tier 1 regions in what is the most economic play in the US. Although it is the same size it is less oily and has $7/boe capex and $8/boe opex.

"We can see strong (shale) production growth, strong cash surpluses that gives us a balance in our portfolio where you can ramp investment up and down, you can moderate that, very unlike deepwater which is quite chunky. They sit nicely together in a portfolio." Andy Brown, Shell Head of E&P



Economic comparison of shale vs. deepwater

- The table on the right is a comparison of the key metrics for the generic US onshore Permian (Midland) development versus an average African deepwater offshore development (Mauritania).

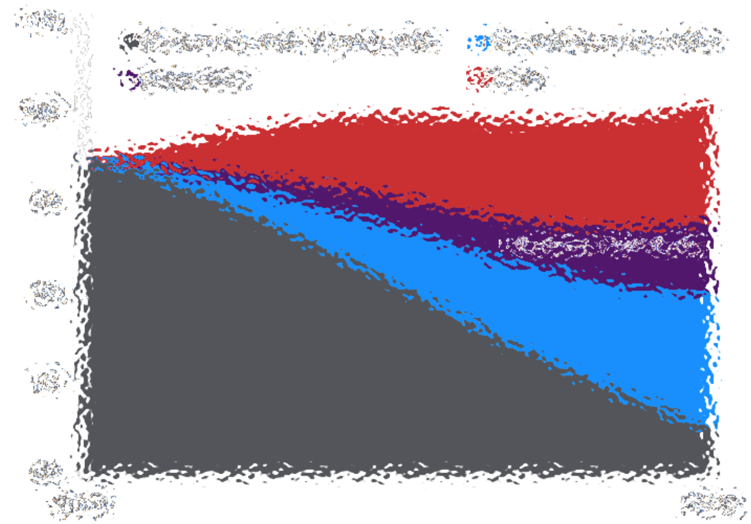
Main metrics for US Permian vs. Mauritania developments

Shale vs deepwater: production and revenue

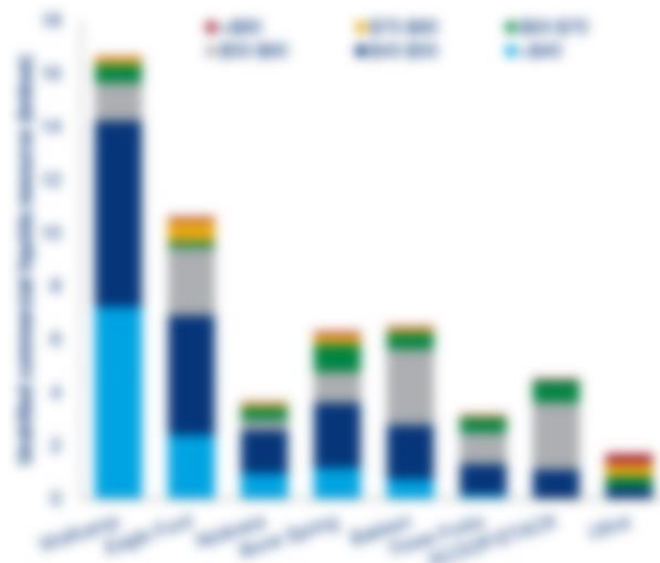
Can shale alone meet oil demand growth?

- US onshore has 194Bbbl of technically recoverable crude reserves according to the EIA >100 year reserve life. Around a quarter comes from the Permian.
- However, the best areas are being developed first and over time higher prices will be needed to encourage development of the lower tier acreage.
- Future shale oil production depends on:
  - the quality of the resources
  - the evolution of technological and operational improvements to increase productivity per well and to reduce costs (see appendix page 75)
  - market price

Production outlook to 2025 (mmbbl/d)



Key play remaining liquid resources

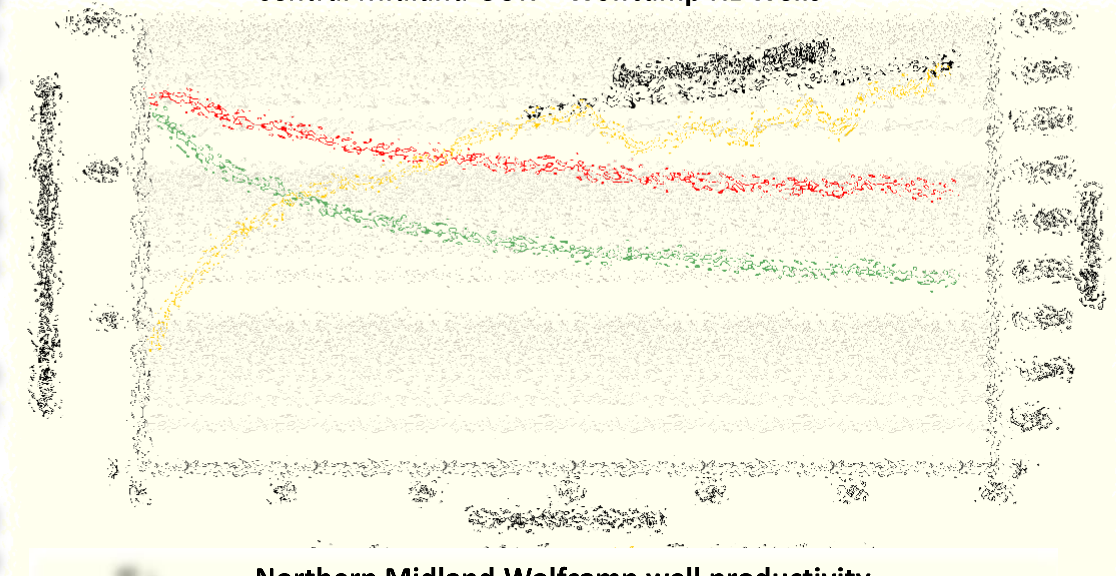


"When you look at the mix you need offshore, you need deepwater. The onshore by itself won't be enough to make up for the decline rates that you are seeing globally," Lorenzo Simonelli, Chief Executive Officer of energy services company Baker Hughes

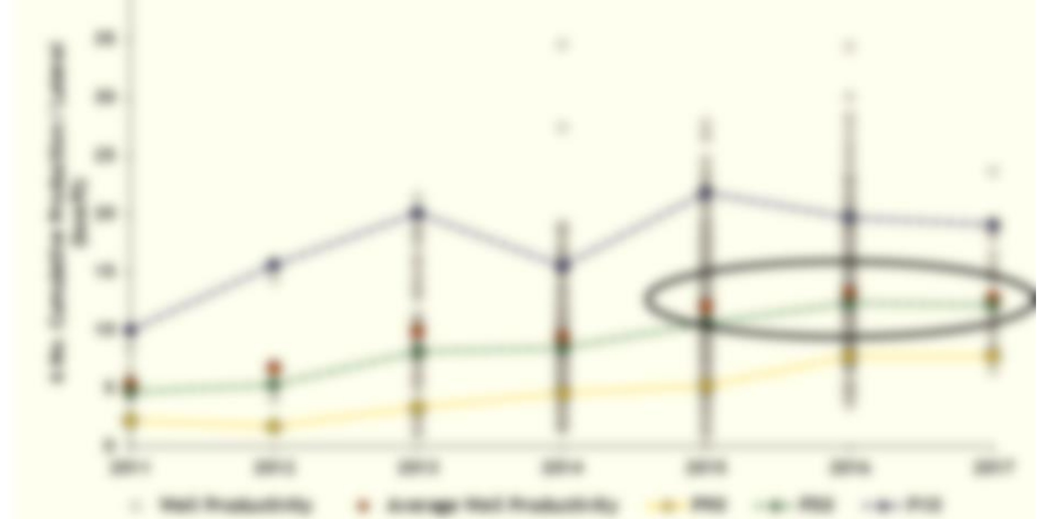
Shale productivity gains over?

- In the Permian, aggregate production data suggests wells are not improving (normalized for lateral length). Further improvements will require best in class G&G/Engineering
- The Gas-Oil Ratio (GOR) is the ratio of produced natural gas rate (standard cubic feet) to produced oil rate (barrel), and has increased rapidly in parts of the Permian Basin
- The risk of increasing GOR that is being seen could potentially negatively impact well & reservoir performance.
- Rapidly increasing GORs are not good, but it remains to be seen how bad they are to long-term well/reservoir performance (see top chart).
- Most recent vintage Permian data suggesting type curve improvements are slowing/plateauing (normalized for lateral length). Era of easy gains with more sand maybe be waning (see bottom chart).

Central Midland GOR – Wolfcamp Hz Wells



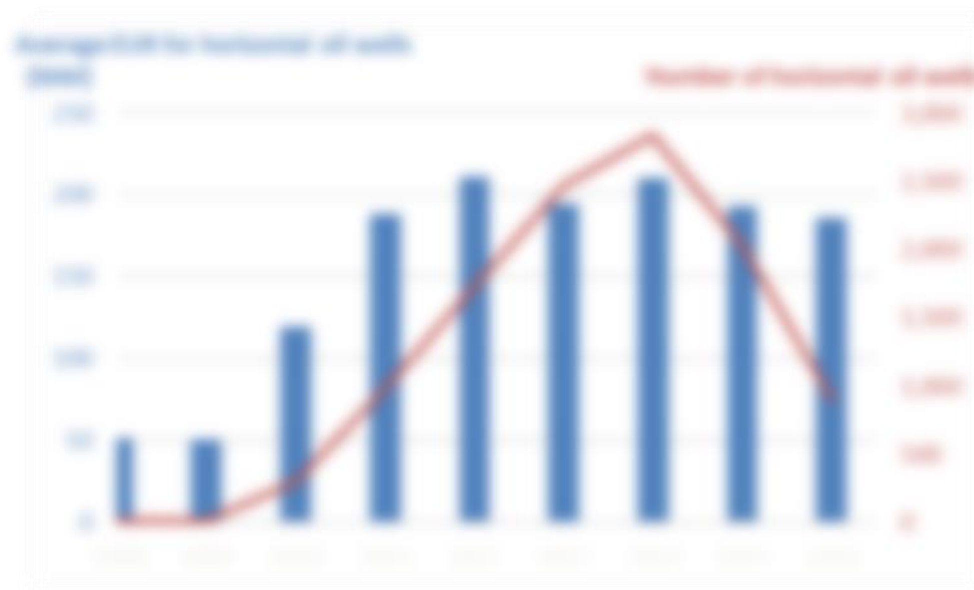
Northern Midland Wolfcamp well productivity



Eagle Ford case study

- Generally in the early stages of a play EURs increase as the sweet spots are identified and there is optimisation of operations.
- Then you will see optimisation of completion techniques, lateral lengths and well spacing which may increase IP rates but EURs stay flattish given higher declines.
- As development of a light oil or shale gas play continues, the EUR per well decreases as companies move into non-core acreage and reduced well spacing can lead to interference between wells.
- Higher prices or lower costs are needed to improve economics.
- The range of EURs across counties and within each county can be large

Average crude oil EUR and number of wells drilled in the Eagle Ford



Investor and company perception: deepwater

- **There are a number of issues that are keeping investors and companies away from the international E&P space in which stock performance has been dire over the last 5 years:**
- **Lack of exploration success** – Investors have become disillusioned by the lack of commercial success in the last few years. There was high spending on extremely expensive and high risk frontier exploration.
- **Companies have pulled out of exploration** – US E&Ps have all but exited, NOCs have pulled back from deals and exploration, Integrateds have reduced spend. Drilling activity in 2017 was down by ~60% on 2014.
- **Appraisal failures** – Investors have seen a number of high profile discoveries turning out to be likely non-commercial (e.g. Shenandoah; Paon; Pecan).
- **Inability to farm-out discoveries** – There have been a number of discoveries in some cases fully appraised, that E&P companies have been unable to farm out for years. In general there has been limited M&A. Cobalt, the most successful explorer in Angola has struggled to sell its oil discoveries and agreed a deal (which fell through) with Sonangol for <$3/boe, which is less than it invested.
- **Deepwater development disappointments** – Many deepwater projects haven't reached full capacity and have encountered unanticipated issues along the way. Also there have been lots of projects that have seen cost over-runs.
- **Move to shorter cycle** – Given the short-cycle nature of investors, the implication is that companies have moved away from wanting to invest in long-term deepwater projects and prefer shorter cycle shale.
- **Trading liquidity for stocks** – Many investors need a certain amount of trading liquidity to be able to own stocks. Given the reduction in market cap and lack of interest in the space, the trading liquidity on a number of E&P stocks has fallen sharply.
- **Corporate governance and management issues** – The E&P sector has seen a number of scandals (e.g. Afren, Gulf Keystone, HRT and OGX) and confidence in management teams is low.
- **Tax risk** – There have been a number of instances where companies have sold assets and retrospective capital gains tax has been levied (e.g. Cairn in India; Tullow in Uganda).

Investor and company perception: shale

- **Although US production has seen a resurgence in recent years, not all shale focused companies have performed well as investors have taken issue with the lack of cash generation. There has also been increased pressure on executive remuneration and targets with high G&A seen at a lot of companies.**
- **Outspend** – Since 2007 energy companies have spent $280 billion more than they generated from operations on shale investments. A number of companies have gone into Chapter 11 but then re-emerged.
- **Core inventory** – There is a balance between having too much inventory and the holding cost of it versus having too little and at some point having to do something about it.
- **High grading** – Companies drill their lowest cost/best return prospects first. Therefore over time one should expect a deterioration in the quality of the well results and in long-term capital efficiency.
- **Environmental risk** – There is the perception that fracing is harmful as it uses immense amounts of scarce water, contaminates the groundwater, emits carcinogenic chemicals, or causes earthquakes.

"If you give a driller a dollar, he's going to drill a hole."
Stanley Druckenmiller

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