Lessons learnt from recent dry wells in northwest Africa

Jonathan David Castell\textsuperscript{1*}, James Scotchman\textsuperscript{1} and Thomas Butt\textsuperscript{1} look to understand the principle risks identified in previous drilling campaigns to help de-risk future exploration in the Mauritania-Senegal-Guinea Bissau-Conakry (MSGBC) Basin.

The Northern Mauritania-Senegal-Guinea Bissau-Conakry (MSGBC) Basin — success followed by failure

Industry interest in the Mauritania-Senegal-Guinea Bissau-Conakry (MSGBC) Basin has heightened in recent years with the SNE and FAN discoveries, offshore Senegal in 2014, as well as a successful drilling campaign in 2015-16. Recently, however, many high-profile dry wells suggest that the geological risks in these basins are not fully understood at present.

The first exploration-drilling programme during 2015-16 (led by Kosmos Energy in partnership with BP) boasted a 100% success rate across five wells. It included major dry gas discoveries at the Greater Tortue Complex (Tortue, Ahmeyim, and Guembeul), Marsouin, and Teranga. During this campaign, more than 50 Tcf of gas was discovered. The wells targeted gas reservoirs in Cenomanian channel sandstones in combination traps with a strong structural component. Although industry excitement was high regarding the large gas volumes discovered, many exploration and production (E&P) companies hoped for the potential of significant volumes of economically recoverable oil in the basin.

With the objective of discovering a new oil province, the 2017-18 drilling campaign shifted from slope-channel sandstones to focus on an outboard basin floor fan fairway. A liquids-rich pay zone was believed to be more likely here because of expected lower maturities of potential source rocks basin-ward. Four independent prospects were high graded from a large inventory to provide the best chance of discovering liquids in volume. The wells were drilled between May 2017 and January 2018 and resulted in a 25% success rate (with the only discovery of dry gas). The results of wildcats provide hard evidence for where the petroleum system works and where it does not. Commonly, many of these failures constitute a prospect-specific risk. However, understanding the likely chance of this risk reoccurring on a new prospect is key to future exploration campaigns. Therefore, placing these wells in the wider context of a basin review, it is possible to better understand and differentiate basin-scale risk and prospect-scale risk.

What makes the play? Targeted petroleum system elements

First, it is important to consider the petroleum system elements of the targeted plays during the 2017-18 campaign.

Source and charge

A principal aim for the 2017-18 campaign was to test the presence of an Early Cretaceous and/or Cenomanian source interval believed to be oil mature. The presence and effectiveness of this source rock is proven to the south, where it is observed to charge the largest global oil discovery in 2014 — the SNE deepwater.

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Figure 1 Map showing the discoveries made during the operators’ 2015-16 drilling campaign and the prospects identified for the 2017-18 programme. Oil was encountered to the north at Tiof and Chinguetti but appears absent in discoveries made to the west.
Well results — making the most of disappointment

Yakaar-1: gas
Kosmos Energy spudded Yakaar-1 in May 2017 (the first well drilled during the 2017-18 campaign). The prospect was located approximately 25 km down-dip of the Teranga-1 gas discovery made in Cenomanian channelized sandstones during the previous drilling programme. Yakaar-1 was predicted to encounter the base of slope fan facies fed by the associated up-dip channel system. Thick, stacked reservoir sands with good porosity and permeability were encountered. The operator announced that Yakaar-1 intersected a gross hydrocarbon column of 120 m (394 ft) in three pools within the primary Lower Cenomanian objective and encountered 45 m (148 ft) of net pay (energy-pedia, 2017a). This discovery, 15 Tcf of gas (Kosmos Energy, 2017), although disappointingly not oil, was the largest hydrocarbon discovery of 2017. In particular, it proved the basin floor fan play concept that would be targeted in subsequent wells.

Hippocampe: dry
The second well of the campaign, Hippocampe-1, was drilled in August 2017. It was located to the north of the proven gas trend, and the operator was hoping for liquids charged from an unproven Early Cretaceous source (Kosmos Energy, 2017). The well was intended to test Cenomanian basin floor fans that displayed strong seismic attribute support for hydrocarbons, including calibrated amplitude variations with offset (AVO) and reservoir/trap conformance. The well was declared dry, encountering a good quality but water-bearing reservoir. The lack of charge was cited as the cause of the failure, although it did confirm reservoir presence in the deep basin (energy-pedia, 2017b).

Lamantin: dry
Lamantin-1, spudded in November 2017, was located far to the north of Hippocampe in Block C-12, northern Mauritania, and was a departure from the trend being tested in previous wells. Pre-drill analysis by Kosmos Energy suggested an increased probability for liquids because of the prospect’s proximity to the Cenomanian-Turonian charge kitchen; this prospect was regarded as the best opportunity for an oil discovery (Kosmos Energy, 2017). The target was younger here — Campanian base of slope sands in a combination structural-stratigraphic trap, with a significant flat spot visible on seismic data (energy-pedia, 2017c).
The results from this well were also disappointing. Reservoir sands were identified but were water-bearing, with only residual hydrocarbons present. A lack of sufficient trap was the suggested failure cause, related to a combination of up-dip sand pinchout and top/base seal effectiveness.

**Requin Tigre: dry**

The final well in the campaign, Requin Tigre-1, was spudded in December 2017. The well tested the largest prospect of the campaign — a Cenomanian basin floor fan, down-dip of the Greater Tortue complex, with a predicted gross resource of approximately 60 Tcf (Kosmos Energy, 2017). In early 2018, the well was declared dry. Although no reason was provided for the failure, a lack of charge and/or trap failure was suspected (energy-pedia, 2018).

**Understanding the results in a basin-scale context**

Although the results of the wells could be considered disappointing, they have provided useful information regarding the predictability of the play basin-wide and the key considerations for future exploration:

- **Reservoir appears ubiquitous across the basin.** All wells penetrated thick, stacked reservoirs with good porosities and permeabilities. This suggests that reservoir presence in the basin is predictable and reservoir quality should not be considered a major concern.

- **Gas remains the dominant phase in the basin.** A liquids fairway is yet to be proven.

- **Access to the gas charge is not uniform across the basin.** It is suspected a complex migration network is present.

- **Trap effectiveness is a key risk.** Prospects relying on stratigraphic, up-dip pinchouts in basin floor fan sands should be considered high risk (e.g., Lamantin and Requin Tigre). Combination trapping styles are preferable.

- **Positive AVO and flat spot identification.** Although useful tools in exploration, such techniques should be used with caution.

The assessment of the wells drilled during 2017-18 identified two key risks in the northern MSGBC Basin, which will be further discussed in the subsequent sections.

I. **Charge and phase:** Based on previous well results, and in-house maturity modelling, the chances for a liquid-rich play are believed to be unlikely. Through a rigorous understanding of the subsurface geology and potential source rocks in the basin, is it possible to predict where a liquid fairway might exist, if at all?

II. **Trap:** Many of the outboard basin floor fan plays rely on stratigraphic, up-dip pinchout as the trapping mechanism. Identification of subtle structures or proximity to sub-marine features (e.g., seamounts) might mitigate this.

### Assessing charge — what is sourcing the gas?

Two of the four wells (Hippocampe and Requin Tigre) are believed to have failed because of a lack of charge (Table 1), and no evidence of liquid hydrocarbons was present in any of the wells. The following discussion considers the likely source of gas and discusses issues encountered with identifying a significant liquid charge in large parts of the basin.

The only successful well drilled on the outboard trend was the gas discovery at Yakaar-1, which confirmed the charge presence in this area. To date, limited information has been published on

<table>
<thead>
<tr>
<th>Well</th>
<th>Country</th>
<th>Spud</th>
<th>Block</th>
<th>WD</th>
<th>TD</th>
<th>Pre-Drill Volumetric Estimate [Kosmos Energy 2017]</th>
<th>Reservoir Target</th>
<th>Gross HC Column</th>
<th>Net Pay</th>
<th>Result</th>
<th>Assumed Failure Cause</th>
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<tbody>
<tr>
<td>Yakaar-1</td>
<td>Senegal</td>
<td>May-17</td>
<td>Cayar Profond</td>
<td>2550 m</td>
<td>4700 m</td>
<td>15 Tcf</td>
<td>Cenomanian Basin floor fan</td>
<td>120 m</td>
<td>45 m (3 pools)</td>
<td>Gas Discovery</td>
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</tr>
<tr>
<td>Hippocampe-1</td>
<td>Mauritania</td>
<td>Aug-17</td>
<td>C-8</td>
<td>2600 m</td>
<td>5500 m</td>
<td>12 Tcf+</td>
<td>Cenomanian Basin floor fan</td>
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<td>N/A</td>
<td>Dry (water bearing)</td>
<td>Lack of charge</td>
</tr>
<tr>
<td>Lamantin-1</td>
<td>Mauritania</td>
<td>Nov-17</td>
<td>C-12</td>
<td>2185 m</td>
<td>5150 m</td>
<td>2 to 3 Bboe</td>
<td>Campanian Basin floor fan</td>
<td>N/A</td>
<td>N/A</td>
<td>Dry (water bearing with residual hydrocarbons)</td>
<td>Lack of viable trap</td>
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<tr>
<td>Requin Tigre-1</td>
<td>Senegal</td>
<td>Dec-17</td>
<td>Saint Louis Profond</td>
<td>3100 m</td>
<td>5200 m</td>
<td>60 Tcf+</td>
<td>Cenomanian Basin floor fan</td>
<td>N/A</td>
<td>N/A</td>
<td>Dry</td>
<td>Unknown. Lack of charge and/or trap likely</td>
</tr>
</tbody>
</table>

WD = water depth  
TD = total depth  
HC = hydrocarbon

*Table 1 Summary of the wells drilled during the 2017-18 exploration drilling campaign.*
the nature of the gas at Yakaar-1, although it is predicted to be similar to that discovered at Tortue, Marsouin, and Teranga.

The origin of the dry gas in the Tortue, Marsouin, Teranga, and Yakaar discoveries has not been conclusively verified. The well-known Cenomanian–Turonian and Albian source rocks are immature in these discovery areas, though they are believed to have charged discoveries at SNE and FAN to the south. With this in mind, it could be considered that a deeper stratigraphic interval could be charging the gas. Our analysis suggests that a Jurassic source rock is most likely.

An Early Jurassic source?
Organic enrichment during the Jurassic has been observed along the northwest African Margin in a number of basins. Through the utilization of in-house geodynamic modelling, assumptions can be made regarding the presence of similar facies in the MSGBC Basin.

In Morocco, Early Jurassic source rocks are a proven source of oil in the onshore pre-rift basin. Offshore, a similar interval of Early Jurassic age is believed to have charged Middle and Late Jurassic accumulations in the Cap Juby area.

In Mauritania, oil shows in Rad el Beida-A1 have a distinctly different character from the Cretaceous sourced oils located elsewhere in the MSGBC Basin and are more similar to those in the Cap Juby area (Vear, 2005). Low diasterane and high gammacerane contents have been used to interpret a carbonate- and evaporite-influenced source rock for the Rad el Beida-A1 oils, which are consistent with the syn-rift, early Jurassic sediments.

Onshore Senegal, isotopic evidence consistent with a contribution of hydrocarbons from a Jurassic source rock exists (Carr et al., 2015).

All of these source rocks have been modelled to have been deposited in a restricted seaway during the initial stages of the Central Atlantic opening (Figure 3). The scale of this event could develop a higher chance for widespread (both temporally and geographically) distribution of these organic-rich facies.

In-house paleo-climate modelling suggests the potential for wind-driven upwelling on the northwestern African coast during the Liassic period, which might have given rise to the presence of an organically enriched interval and a potential source rock.

The Early Jurassic is buried deeply across most of the basin (approximately 7 to 8 km), and maturity mapping suggests that it would be gas-mature to over-mature in all but the most distal areas. Kosmos Energy (2017) indicated the gas discovered at Tortue and Teranga has a condensate-gas-ratio (CGR) on the order of 15 to 30 bbl per million standard cubic feet (MMSCF). The CGR at the Yakaar discovery is believed to be similar. Generally, dry/lean gas is classified as having a CGR of less than 50 bbl/MMSCF. The low volumes of liquids correspond with the expected high thermal maturity of Jurassic source rocks in the area of the discoveries (Figure 4).

Oil probability
From the outset of the latest exploration drilling programme, the intention was to prove an effective oil charge in the outboard trend of the MSBGC Basin.

Figure 3
A palinspastic gross depositional environment (GDE) map for the Early Jurassic. Light green areas depict modelled organic enrichment. This is expected to have been widespread in the Central Atlantic during this time.

Figure 4
Maturity map displayed in DecisionSpace Geosciences software for the Early Jurassic, which illustrates widespread gas maturity. High maturity in the area of inboard discoveries is believed to have caused cracking and fractionation of any liquid component, thus resulting in dry gas accumulations.
Oil has been discovered in Mauritania, albeit in relatively modest volumes charged by Cenomanian–Turonian source rocks (Vear, 2005). The Chinguetti, Tiof, and Banda fields have been jointly developed and contain recoverable reserves of 120 million bbl.

To the south, oil has been discovered in large volumes. Discoveries made in 2014 at SNE and FAN, offshore Senegal, prove the presence and effectiveness of the Cenomanian–Turonian source rock, charging both deepwater basin floor fans (FAN-1) and shelfal pro-delta turbidites (SNE) with large volumes of oil. However, offshore Mauritania, it is believed that both the inboard and outboard trends are down-dip of the Cenomanian–Turonian kitchen area and therefore unable to be charged by this interval (Figure 5).

Kosmos Energy (2017) reports that oil sampled in the Teranga-1 well suggests the presence of Albian, liquid-prone source rock in this area. However, oil has not been reported in any of the discoveries made in proximity to Teranga, suggesting the effectiveness and presence of the Albian source could be considered to be limited.

Assessing trap

In addition to the insufficient charge in the outboard trend, the failure at Lamantin-1 and possibly Requin Tigre-1 highlights the issues with trap effectiveness. The first exploration phase in the basin (in which Tortue, Marsouin, and Teranga were discovered) focused on drilling slope channel sands in anticline structures.

Dailly (2016) reports that these anticline structures could be related to transpression caused by plate rotation from the Santonian to Miocene. Triassic–Jurassic extensional rift faults were reactivated, receiving compressional stress that created these structural traps. A plate scale rotation facilitating the development of structure (Dailly, 2016) would be expected to cause a large number of anticlinal features. However, this does not appear to be the case.

The 2017-18 exploration on the outboard trend extends beyond the known extent of these anticlines, where available seismic data suggests that much less structure is present (Figure 6). As a result, these prospects have a much higher reliance on stratigraphic trapping mechanisms, particularly the up-dip pinchout of sandstones from the basin floor fans. This is not necessarily a problem — stratigraphic traps have been proven to be effective at Yakaar-1.

Conclusions and considerations

The MSGBC Basin is now established as a world-class gas province. Gas charge is widespread in the basin and analysis suggests that hydrocarbons originate from the Jurassic period (most likely Early Jurassic) source rocks. Recent drilling also demonstrated...
that thick, good-quality reservoirs are readily predictable, even away from proven hydrocarbon accumulations.

When compared with the 2015-16 exploration drilling campaign, which boasted a 100% success rate, the 2017-18 campaign was in part disappointing. Only one gas discovery was made (albeit a large one) and potential for significant oil finds still remains unproven. The drilling campaign confirmed the following key risks in the basin, which should be considered in future programmes:

- **Oil charge.** This evaluation predicts that the established Cenomanian-Turonian, oil-prone source rock is immature across the 2017-18 exploration area. Some evidence exists for liquids sampled from Teranga-1, typed to an Albian source. Despite this, only limited information is available relating to these oils, which might suggest they constitute only a minor contribution to petroleum systems in the area. Oil charge is believed to be unlikely away from the Cenomanian-Turonian kitchen area and is only proven to exist to the east (Chinguetti) and to the south in Senegal (SNE).

- **Gas charge.** Although still relatively low risk, it is now clear that charge is not ubiquitous across the basin (as illustrated by the lack of charge at Hippocampe-1). Understanding migration pathways will be crucial to avoiding similar issues and will require a detailed database and ability to devise complex migration models.

- **Trap effectiveness.** The lack of a viable trap at Lamantin-1 demonstrates that this risk is significant. Heavy reliance on stratigraphic trapping geometries, away from anticline structures, increases the trap risk in those areas.

With this in mind, attention now turns to the purchase of three deepwater blocks offshore Mauritania by ExxonMobil (energy-pedia, 2017d). Risks highlighted by the 2017-18 drilling campaign are expected to remain pertinent to the identification of potential prospects in the deep water. In addition, the presence of reservoir in these blocks is beyond known extents and could present some risks not perceived to be present inboard.

The recent exploration has allowed consideration of at least two potential development hubs for liquefied natural gas (LNG) in the MSGBC Basin: Tortue-Marsouin and Teranga-Yakaar. Despite the low CGR of the gas discovered to date, the large overall discovered resource is likely to make the economics of any development attractive. Opportunities to discover further accumulations in other parts of the basin exist, although this fairway is expected to have limited liquid potential.

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**References**


