Submitted abstract

Reservoir Characterization in the Somalian Deepwater Frontier: Using a Worldwide Database to Predict Reservoir Quality

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Introduction

Reasoning by analogy has been used at least since the time of Aristotle (384-322 BCE) to estimate the unknown from the known. Estimation by analogy is important to exploration companies because it provides them with the credible data ranges needed to make risked investment decisions.

The theory behind using analogues is simple: If two data sets A (analogue dataset) and B (target dataset) share certain critical properties, such as structural style, tectonic setting, reservoir age, burial depth etc that exert control over a desired variable known in A, but unknown in B, then the range of that variable in A will provide a credible estimate of it in B. For example, in data set A, the porosity of the reservoir is known to be within the range 20-25% in the depth range of 10,000-12,000 ft. In the target data set B, the depth of the reservoir is known to be between 10,000-12,000 ft, then we may deduce that the range of porosity that is known in the analogues also occurs in the target.

A searchable database of worldwide deepwater reservoirs (the Cossey Deepwater Database) was used to define sets of analogue data for clastic play fairways mapped in offshore Somalia. This methodology was chosen because the Somalian margin has minimal available well data, but does have good quality 2D seismic data from which reservoir presence and depth could be inferred. Using the analogues defined in this way enabled the definition of credible predictive ranges under a variety of scenarios to input to volumetric models, thereby capturing the shape of the uncertainty distribution and better-define the business opportunity.

Methodology

The Mogadishu and Jubba Deep basins, offshore Somalia, are a classic Frontier province. Only one exploration well penetrating the clastic target reservoirs has been drilled in these basins (Pomboo-1, 2007), which are otherwise only constrained by a widely-spaced grid of 2D data (Figure 1).

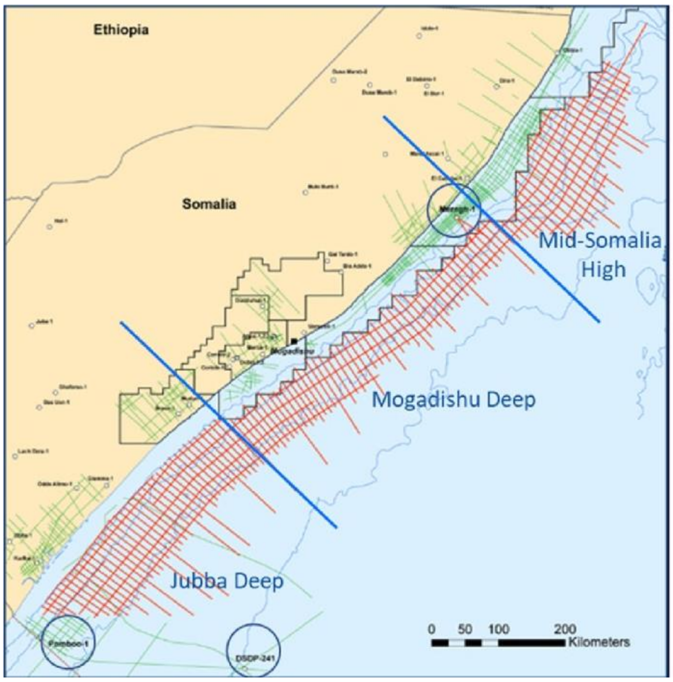


Figure 1 *Interpreted seismic grid (red) and wells used for calibration and major sub-basins in the Somali passive margin basin (modified from Davidson et al. 2018).*

Classical seismic facies techniques and regional geological analysis were used to identify potential sand-prone intervals in both the Cretaceous and Palaeogene sections in the basins. In order to establish the possibility of eventual economic production from these potential reservoir-prone intervals, it was necessary to estimate the likely ranges of static reservoir parameters such as porosity, permeability, net pay, net/gross and possible dynamic parameters such as recovery factor, production rates (% of oil or gas produced in peak year) and oil recovery per unit volume of the reservoir.

The Cossey Deepwater Database was used to define sets of analogue data for offshore Somalia. Searches of the database were conducted for Jurassic, Cretaceous and Eocene and Paleocene offshore oil and gas fields in passive margin tectonic settings. Once those data were processed, additional information was manually added from within, or close to, the study area. The search for only Jurassic fields was conducted without specifying the tectonic setting. An additional search was conducted to find Cretaceous age (65-145.6 Ma) reservoirs in deepwater fields to define analogue data for water saturation (Sw) and Formation Volume Factor (Bo).

Results

In deepwater offshore settings, porosity is reduced during burial by compaction and cementation, and enhanced by the dissolution of unstable components during burial as out-of-equilibrium fluids flow through the sands as a result of the compaction of deep basinal sediments, (e.g Burley, 1986). In offshore Somalia, compaction and cementation are likely to dominate as the provenance for sand is cratonic Africa, producing mature/polycyclic sediments. This is a constraint on the choice of analogues.

Porosity in the selected Jurassic and Cretaceous oil fields varies between 15% and 30% (Figure 2) with a mean of 22.1% and median 22%. Figure 2 shows a trend of decreasing porosity with depth (BML), but with a cluster of fields in the center of the trend. It includes the Mbawa discovery in Kenya and the Campanian sands penetrated by Pomboo-1 well. In addition, porosity from onshore wells (Brava-1, Jurassic and Paleocene reservoirs) seem to fit the trend shown by the green line.

Search 1 Fields (inc Mbawa)

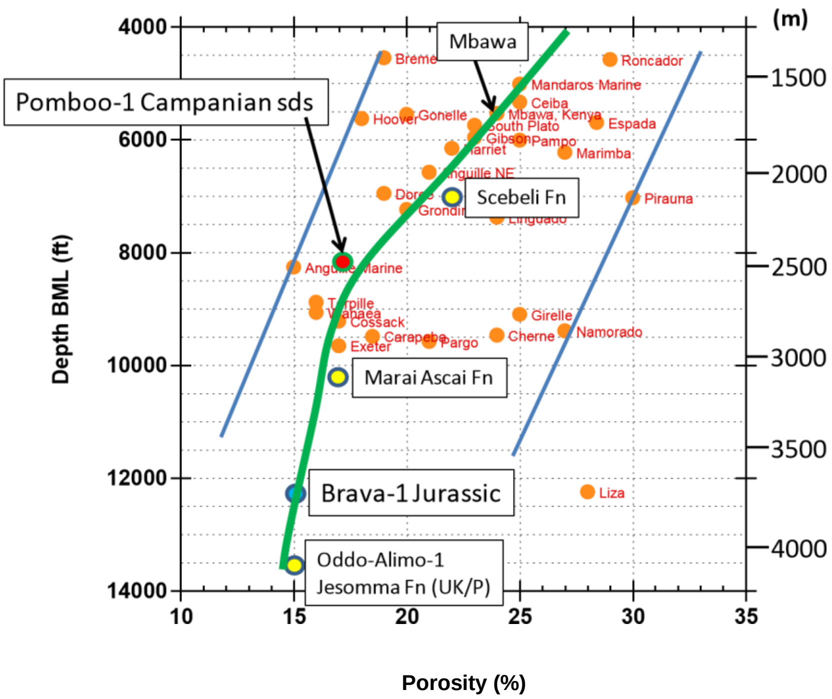
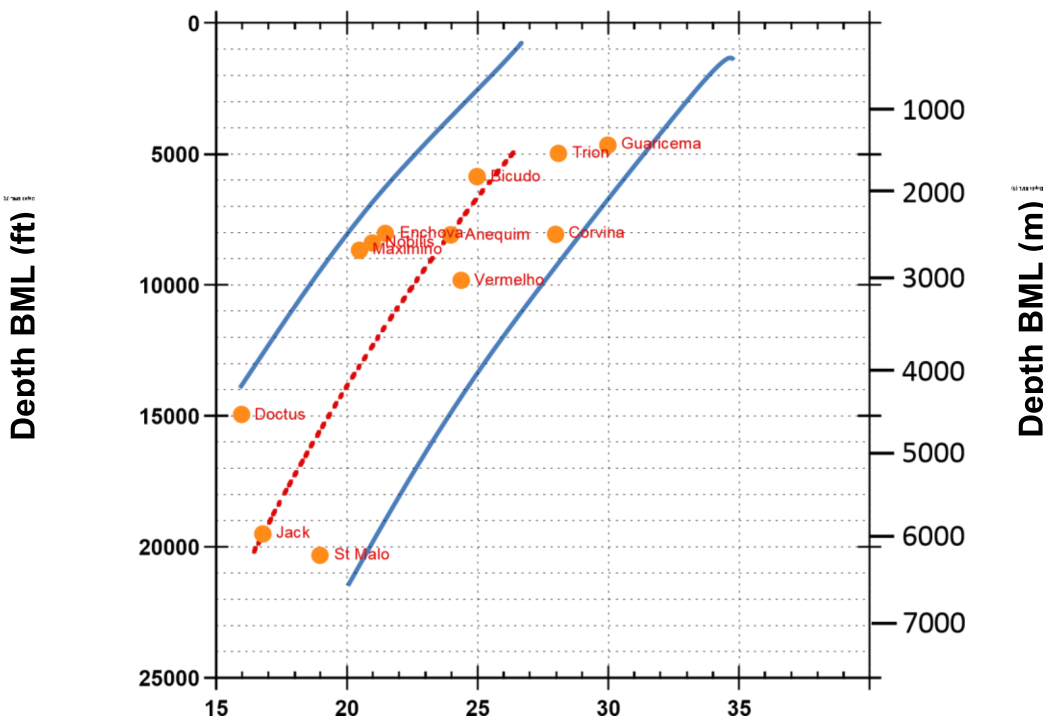


Figure 2 *Plot of porosity vs. depth (below mud line) for worldwide Jurassic and Cretaceous oil fields (passive margin, offshore). Also shown are Pomboo-1 Campanian sands (red dot) and Paleocene (yellow) and Jurassic (blue) data points from onshore Somalia well Brava-1.*

If Jurassic and Cretaceous gas fields are included in the dataset, then the minimum changes to 14% and the mean changes to 22%.

Porosity in Eocene and Paleocene worldwide oil fields (Figure 3) varies between a minimum of 17% and a maximum of 36% and the mean value is 24.8% and the median is 24.4%. Some worldwide Paleocene oil fields can have porosity as high as 19% at 6000 m BML.



Porosity (%)

__Figure 3__ Plot of porosity vs. depth (below mud line) for worldwide Eocene and Paleocene oil fields (passive margin, offshore). The blue lines define the trend of reducing porosity with depth BML.

Other parameters, such as net/gross, recovery factor and oil production in peak year for Jurassic and Cretaceous worldwide oil fields were compared using cumulative probability plots (Figure 4).

Net/gross was calculated from the amount of net reservoir from the top of the reservoir interval to the base of the reservoir interval and expressed as a percentage. Net/gross in worldwide Jurassic and Cretaceous oil fields varies between a minimum of 42.3% and 86% (Figure 4). The mean value is 64.6% and the median 65%. If Jurassic and Cretaceous worldwide gas fields are included in the dataset, then the mean changes to 66.3% and the median changes to 70%.

In the database, primary recovery efficiency (RF) is recorded as a percentage and is the value reported from published data. RF in Jurassic and Cretaceous worldwide oil fields varies between a minimum of 27% and a maximum of 52% (Figure 4) and the mean value is 36.1% and the median 36%. If Jurassic and Cretaceous worldwide gas fields are included in the dataset, then the maximum increases to 75% and the mean value changes to 38.6%. RF in Eocene and Paleocene worldwide oil fields varies between a minimum of 25% and a maximum of 47% and the mean and median values are 36%.

Production in peak year is reported as a percentage and is calculated within the database by dividing the EUR for gas and oil by the annual production for the peak year. The percentage production in peak year in Jurassic and Cretaceous worldwide oil fields varies between a minimum of 2.3% and a maximum of 28.7% (Figure 4) and the mean value is 10.7% and the median is 9.8%. If Jurassic and Cretaceous worldwide gas fields are included in the dataset, then the median increases to 10% and the mean value changes to 10.9%. The percentage production in peak year in Eocene and Paleocene oil fields varies between a minimum of 3.5% and a maximum of 18.8% and the mean value is 9.3% and the median is 8.8%.

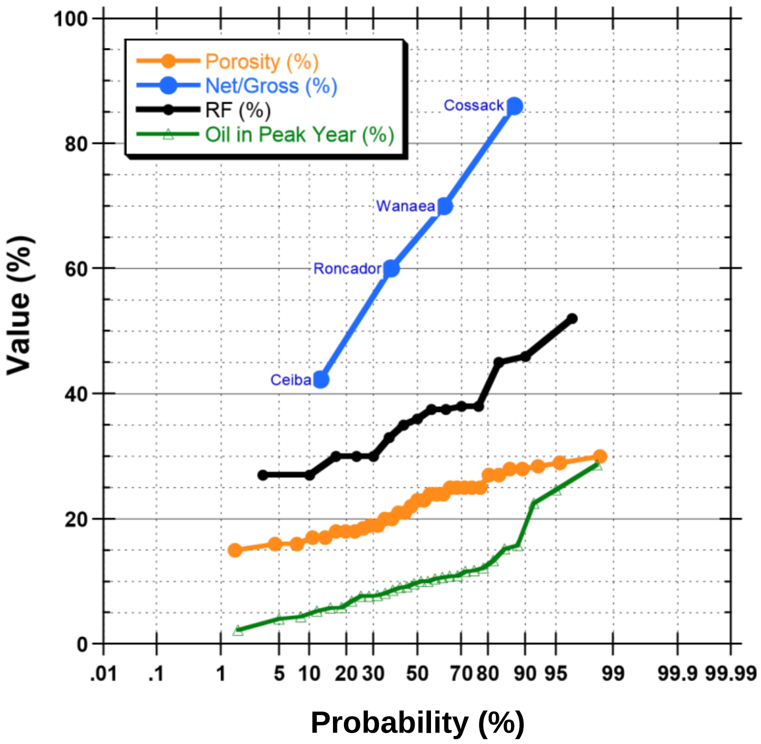


Figure 4 *Cumulative probability plot of porosity, net/gross, recovery factor, oil in peak year for Search 2 (Jurassic and Cretaceous oil fields, passive margin, offshore).*

A companion reservoir database was used to estimate other reservoir parameters for Cretaceous age oil reservoirs, such as water saturation (Sw) and formation volume factor (Bo). In a search for Cretaceous age oil reservoirs, water saturations vary between a minimum of 18% and a maximum of 40%, with a mean of 22.3% and Formation Volume Factor (Bo) varies between a minimum of 1.16 and a maximum of 1.25, with a mean of 1.2.

Conclusions

A Best Practice for reservoir quality prediction in frontier areas is to use worldwide analogue trends and cutoffs that mirror the viable reservoirs in the database. A risked upside may be posited if the basin is overpressured, and a risked downside if the provenance has strong lithic component.

The use of worldwide analogues was critical to providing boundary conditions for the economic models used by project engineers in notional EUR estimation in the offshore Somalia frontier.

References

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