Pelotas Basin – De-risked Unexplored Cretaceous Potential

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Abstract

Whilst Cretaceous clastic slope and basin floor plays on the Atlantic passive margin have provided an industry focus for exploration for the last 15 years, from the Santos Basin to the Malvinas Basins in Brazil, Uruguay and Argentina there has been only one deep water well (Raya-1 in Uruguay) which terminated in the Tertiary. Although the Cretaceous plays in Uruguay may lie in ultra-deep water, to the north, along strike in Brazil, the same plays lie in more accessible water depths in the Pelotas Basin, where the majority of one of the world's great Cretaceous and Tertiary Deltas, remains conspicuously unexplored (Zalan, 2017).

The underlying negative tropes surrounding exploration play factors that have led to the lack of drilling in Pelotas will be reviewed, revealing that reservoir presence, source presence, hydrocarbon phase, trap configuration and size are all extremely positively arranged in Brazil's Pelotas Basin (Dias et al., 1994; Stica and Zalan, 2014).

Early Cretaceous source rock cannot only be postulated but it can be mapped on modern data, and its character and regional variation evaluated. Reservoirs can be mapped and understood in terms of the evolving rift and passive margin. Trap consideration in any clastic slope play can be a concern as up-dip seal provided by faulting or sediment bypass is required to form a trap. However, lower slope and basin floor plays benefit from structural-sedimentological traps generated by plate scale processes of gravity and loading that obviates the need for bypass and creates low-risk Titan-scale traps of unique geometry (Rodriguez et al., 2016).

When each of the play risk factors surrounding exploration are addressed, we reveal a sweet-spot in Pelotas where, in water depths of less than 2km, Cretaceous mixed-system sands, and an Aptian source rock in the oil window all come together in an exciting Cretaceous play-scape of oil potential.

Introduction

Frontier basin exploration requires a detailed petroleum systems evaluation to de-risk firstly and foremost the most critical elements, source rock presence and maturity but also to address the other three key elements, reservoir, trap and seal.

For the Atlantic deep to ultra-deep-water environment the challenge is identifying a potential source rock with the right burial conditions and thermal regime to be mature to produce hydrocarbons.

De-risking source rock presence

Plate tectonic reconstructions (Figure 1), show that up until the Latest Aptian the southern Atlantic remained a restricted seaway which together with the global anoxic event during this period (Schlanger and Jenkyns, 1976; Jenkyns 2010) created the ideal conditions for widespread source rock deposition.

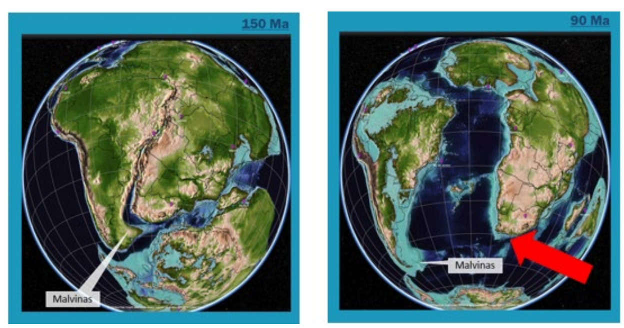

Figure 1 – Plate Tectonic reconstructions between 150 and 90 Ma showing the presence of the Falkland's Plateau which provided a closed seaway in the Southern Atlantic for approximately 60 million years. The seaway was just opening at around 90 Ma.

Presence of Aptian source rock has been proven in basins to both the north, the south and in the conjugate margin, in DSDP well 361 in South Africa (Bray et al., 1998). In Namibia, mature Aptian source rock was reported from the relatively recent HRT wells Wingat-1, Moosehead-1 and Morombe-1 (Petrorio, a, b, c 2015), with light oil recovered from the Wingat-1 well.

Seismic data along the southern Atlantic margin shows strong indications of an Aptian age source rock interval deposited above oceanic crust with an observed consistent low frequency, semi-transparent low amplitude character, interpreted to be associated with source rock presence. Additionally, various source rock characterization studies (Loseth et al., 2011; Vernik and Landis, 1996; Sayers, 2013;) of this interval (Eastwell et al., 2018) show a strong amplitude anomaly with an expected decrease in acoustic impedance, due to the velocity and density decrease associated with Kerogen presence, as well as an AVO Type IV anomaly with the amplitude dimming with angle due to the strong anisotropy generated by the horizontally aligned clay minerals. This character has been observed on original legacy data in the Pelotas Basin (Figure 2) and may be mapped regionally to demonstrate the sedimentologic and loading controls on richness and maturity.

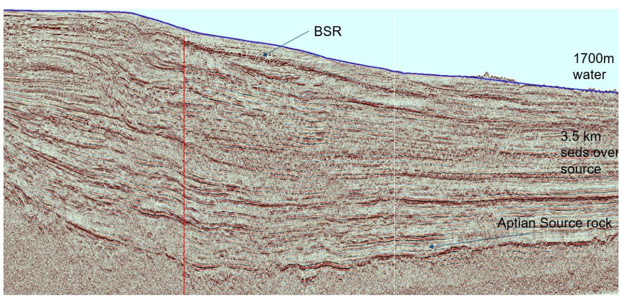

Figure 2 – Original legacy dip line, in time but water depth compensated, in the Pelotas Basin, showing the typical Aptian source rock character observed along the southern Atlantic margin as well as a clear BSR.

De-risking source rock maturity

Determining the geothermal gradient in undrilled regions remains one of the largest areas of uncertainty in frontier basin exploration. Bottom Simulating Reflectors (BSR's) occur at the base of a shallow gas hydrate layer in many of the world's deep-water basins and by calculating the geothermal gradient from the sea floor to the base of the hydrate, quantitative and qualitative inference of the deeper heat flow can be made, ultimately assisting basin modelers in their work.

In the Pelotas Basin the clear and extensive observed BSR (Figure 2), has been used to apply a methodology developed to calculate the temperature at the base of the gas hydrate, which is then used as a proxy for shallow geothermal gradient. The methodology involves mapping the seabed and base hydrate (BSR) and calculating the temperature at the BSR from the Pressure-Temperature phase stability for gas hydrates in a saline medium (Vohat et al., 2003; Hodgson and Intawong, 2013). With an estimate of the sea floor temperature one can derive the geothermal gradient in the shallow section (Kvenvolden and Claypool, 1988).

Once the geothermal gradient is obtained, a structural map of potential source rocks is generated in depth and using the temperature grid obtained from the geothermal gradient, a maturity map is produced in the area covered by the BSR. In the area where a BSR can be confidently picked, the hydrate geothermal gradient for the Pelotas Basin is seen to vary between 28 to 32°C/km (Figures 3 and 4), with a relatively small variation in the dip direction and a slightly greater variation along strike.

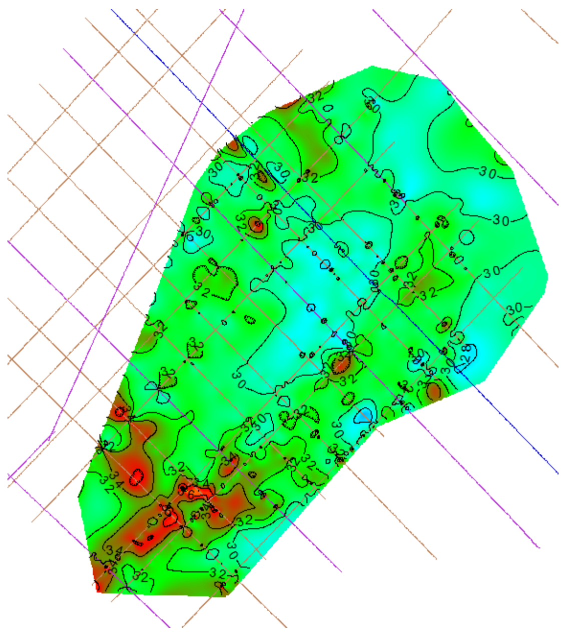

Figure 3 – BSR-derived geothermal gradient grid over the southern Pelotas Basin (low values blue/green 28-30°C/km, higher values to south brown/red 34°C/km).

This is a surprising observation as the crustal architecture is observed to change in the dip direction.

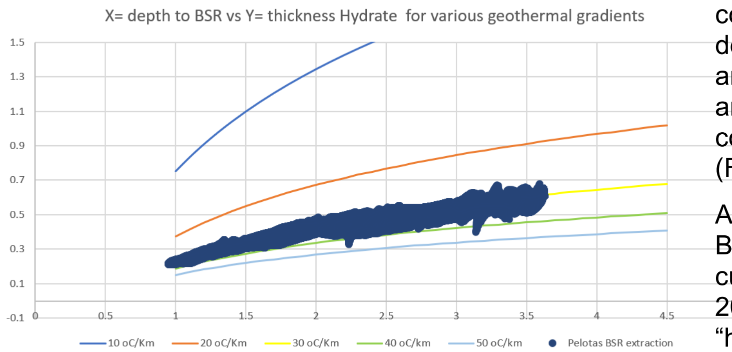

Figure 4 - Depth to BSR vs thickness of hydrate layer, where the lines are geothermal gradients in °C/km. 288K data points were extracted from a 2D mapped 20,000 sqkm BSR in the Pelotas Basin.

Using the hydrate geothermal gradient as an indicator of geothermal gradient, we calculate that under the thickest part of the Pelotas delta the Aptian source rock is likely to be gas and gas condensate generative. However, as the sedimentary column thins radially around the cone, the Aptian source rock is modelled to be in the oil window in the area of the Cretaceous basin floor play in the Pelotas Basin.

De-risking Trap, Reservoir and Seal

Traditional turbidite-centric slope and basin floor depositional models (Figure 5), predict that turbidite currents comprising a mixture of sand, silts and clays sands will transport materials through a confined slope system to the break of slope at the basin floor.

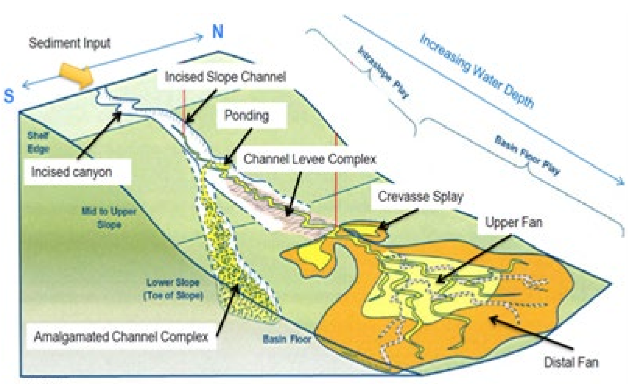

Figure 5 – Deep water slope and basin floor fan depositional model

These slope systems typically have internal meandering channel amplitude character and may be incised or constructional. At the basin floor a reduction in flow velocity of the turbidite allows the coarsest fraction of the entrained load to be deposited. With time and channel avulsion, large, anastomosed fans may develop. On seismic, these are represented as laterally extensive, with continuous amplitude and chaotic internal character (Figures 2 and 6).

Another factor at play on the Argentina to Pelotas Basin margin are strong coast parallel bottom currents (Mutti et al., 2014; Hernandez-Molina et al., 2008). The presence of such currents makes this a “hybrid” system – a mix of gravity driven turbidite currents interacting with orthogonal contourite currents. These systems have a number of unique characteristics pertinent to every aspect of the entrapment of hydrocarbons (Fonnesu et al., 2020). This is observable on seismic in diverse features – from the way that turbidite flows interact with contourite drifts, and in the “fines stripping” of turbidite currents by contourite currents (Mutti et al., 1980). Several examples of the plays both in slope setting and basin floor setting will be demonstrated on seismic.

For the basin floor plays the simple model in Figure 5 can only create hydrocarbon trapping when faulting or a lack of sand in the up-dip channel prevents hydrocarbon migration up-channel to the shelf. Bypass may be caused by the steepness of the channel system preventing coarse clastics depositing or a change of sediment entry to the basin. However, such bypass events are rare and at best hard to prove ahead of drilling, as the thief zones may be sub seismic scale. Of course, DHI and seismic attribute work can guide explorers towards the lower risk traps, yet these methods just reduce risk, and do not obviate it.

Trapping geometry for basin floor fan plays and seal are considered to be the highest risk elements for combined stratigraphic traps such as basin floor fans with three-way dip closure and up-dip pinch out seal. Fortunately, the base of slope play on passive margins also has a surprising twist from the architecture of continental and oceanic crusts. Whether the margin is magma poor or magma rich, close to the continent-oceanic boundary the older cooler volcanic crust that is subsequently loaded by sediment has subsided into the mantle more than the younger oceanic crust further offshore. The first sediments deposited onto this crust therefore dip upwards out to sea. As such, basin floor fans have to seal stratigraphically out to sea, such that they create large low risk traps, on a huge scale. This can be seen on many modern seismic sections that are processed in the depth domain and interpreted in depth or at least depth-converted (Figures 2 and Figure 6). This geometry is observed along both sides of the Atlantic margin where deltas have focused deposition onto the basin floor. However, one challenge for this play is the water depth at which these “up-dip out to sea” basin floor fans can be targeted, which can preclude drilling. For example, in Uruguay, such plays are present below the TD of the Raya-1 well, drilled in over 3400m of water – currently the deepest water exploration well ever drilled.

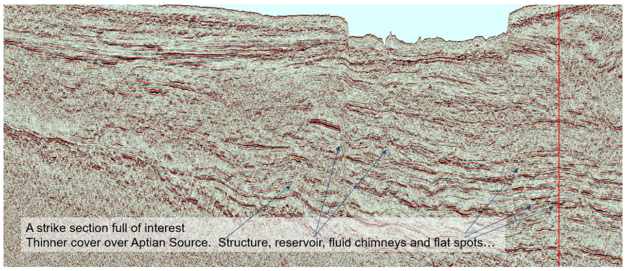

Figure 6 – Original legacy strike line over the Pelotas Basin Prospective Cretaceous play showing potential structures, amplitude anomalies pointing to the presence of reservoir, fluid chimneys and flat spots.

However, oceanic crust is not found at a consistent depth around the world due to the degree of support from underlying mantle convection cells (Hodgson and Rodriguez 2017, 2018, Hoggard et al., 2016). Therefore the stratigraphic traps described here can actually be accessed in modest water depths depending on the relative height of this oceanic crust, and the amount and organization of the accumated sediments at a given location. Whilst convecting mantle can create additional accomodation space as the crust subsides, the volume of sediment and the rate of subsidence of the basin the sediment is depositing in is key. We use regional maps of play distribution and bathymetry to show that whilst the Cretaceous play south fof Brazil may be in ultradeep water (>3km), in the Pelotas basin this play can be tested in water depths less than 2km.

With all the above-mentioned petroleum system elements defined, a deep-water play fairway model has been generated for the Pelotas Basin (Figure 7). This model predicts mature Aptian source presence. Using the BSR-derived geothermal gradient, on the slope and within the Pelotas Delta Cone, gas is the more likely phase, yet at the edges of the Pelotas cone – the source will be in an extended oil maturity window. At the outward edges of the Pelotas delta lies a play of up-dip to sea stratigraphic closures that are perfectly situated to capture and trap the oil generating from this mature Aptian source.

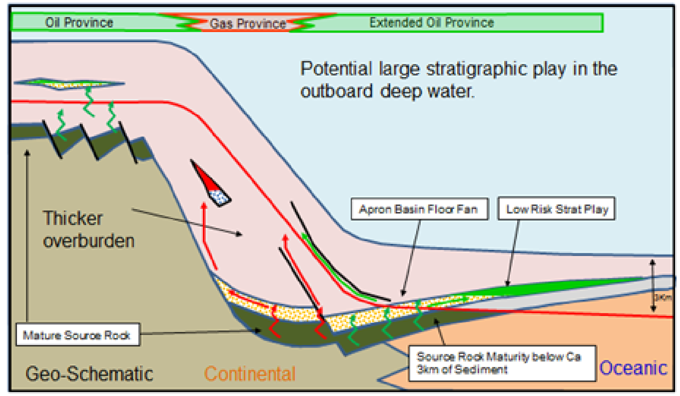

Figure 7 - Deep water basin model illustrates the trapping style, up-dip outboard, of potential large stratigraphic plays

Conclusions

Inhibitors to exploration of the Cretaceous plays below the basin floor from the Santos to Malvinas Basins have comprised a number of factors that with the advent of new technology and a revised approach, can be re-evaluated. The play has all the separate elements of a working hydrocarbon system, source, reservoir, seal and trap that can be found in areas along the margin where all risk factors will be aligned positively. This play is proven in the northern South Atlantic, in the oil discoveries of Sergipe.

In the Pelotas Basin of Southern Brazil, one remaining consideration - water depth above the target location is obviated where a combination of thick sedimentary cone above a strongly subsiding crustal architecture has created an opportunity to explore the Cretaceous basin floor play in relatively accessible and amenable water depths.

That there has been no exploration of Cretaceous basin floor fans south of the Santos Basin in Brazil, Uruguay and Argentina is itself remarkable. However, we suggest not as remarkable as the extraordinary potential of this play.

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