Source rock characterization in frontier basins – a global approach

David Eastwell[1], Neil Hodgson[1*] and Karyna Rodriguez[1] discuss the work carried out to derisk source rock presence and quality in frontier basins by applying a systematic regional evaluation methodology.

Introduction

Exploring in frontier basins carries with it the challenge of identifying and derisking hydrocarbon play elements where well data and consequently, lithological and stratigraphic information is often sparse to absent. In this setting, seismic data will typically be the only source of information available to identify potential play fairways and derisk the corresponding petroleum system elements.

Until recently, the exploration focus of seismic interpretation has predominantly been on developing methodologies to identify structure, traps and reservoir rather than interrogate source rocks. Geophysical deconstruction of the data again focuses on categorizing hydrocarbon-bearing reservoirs, including AVO/AVA (Amplitude vs Offset/Angle) analysis, bright spot/dim spot and flat spot identification. Yet the lack of focus on source is curious as, particularly in frontier basins, the ability to derisk presence and effectiveness (total organic carbon percentage (TOC%) and maturity) of a viable source is key. Therefore, a study has been undertaken to evaluate a number of basins and to characterize the hydrocarbon system and source rocks therein. In conducting this study we have developed a workflow and characterization criteria that provides a significant development in the ability to derisk unproven hydrocarbon plays.

Spectrum has developed a systematic approach for identifying working hydrocarbon systems in undrilled or frontier basins. This workflow is currently being applied to all frontier basins in which Spectrum operates, and in this study the results from a sample of four such basins is presented as well as how lessons learnt in a given basin can provide insight into on-trend and conjugate margins.

Source rock characterization study: datasets and characterization case studies

This methodology begins with a regional plate tectonic and paleo-geographic reconstruction of a margin, which is used to develop an understanding of depositional and stratigraphic basin evolution. This involves identifying time periods and environments where source rock may have been deposited and preserved. The picking of ‘candidate’ source rocks on seismic data, driven by the basin evolution model, is guided in part by the observation that high TOC% oil-prone shale sources typically exhibit a low-frequency, low internal reflectivity character (Figure 4).

Interpretation is then further constrained by the Løseth et al. (2011) criteria which can be used to ‘identify, characterize and map spatial distributions and variations of thick source rocks’. It is suggested firstly that top and base of thick (>20 m) organic-rich claystone should be expressed by a significant reduction and increase in acoustic impedance (AI) respectively. Secondly, the top of this organic-rich claystone should show a reduction in amplitude with increasing reflection angle at the top of the unit. Thirdly, assuming otherwise constant rock composition and consistent embedding rock properties, the amplitude at the top and base of the source unit will vary laterally, rising with increasing TOC% Lastly, the seismic amplitude response vertical profile should reflect the vertical TOC% profile over the source unit.

Finally, this interpretation is integrated with observations from other non-seismic direct hydrocarbon indicators including slick clusters from satellite imagery and pockmarks from multi-beam bathymetry. All of the evidence, data and interpretation is then synthesised to provide a concise evidence base for the presence, character and potential maturity of individual ‘candidate’ sources within a basin. This process can also be used to draw conclusions as to the properties of known source rocks and their geological conjugates which may have been deposited in the same depositional environment, but are subsequently separated owing to rifting and continental drift, as is proposed to be the case for Namibia and Argentina.

Some examples of where this process has been applied are presented, ranging from proven sources in Namibia and The Gambia, to proposed sources in Somalia and Argentina. Figure 1 shows a map of each of the four regions presented in this study, and Spectrum’s 2D broadband datasets which have been interpreted.

Namibia

Offshore Namibia is one of the few Atlantic basins where both the shallow and deep water components of the Barremian-Aptian regional marine shale has been penetrated and derisked as a proven hydrocarbon source by exploratory wildcat wells. The near-shore Barremian-Aptian section is the main source rock to

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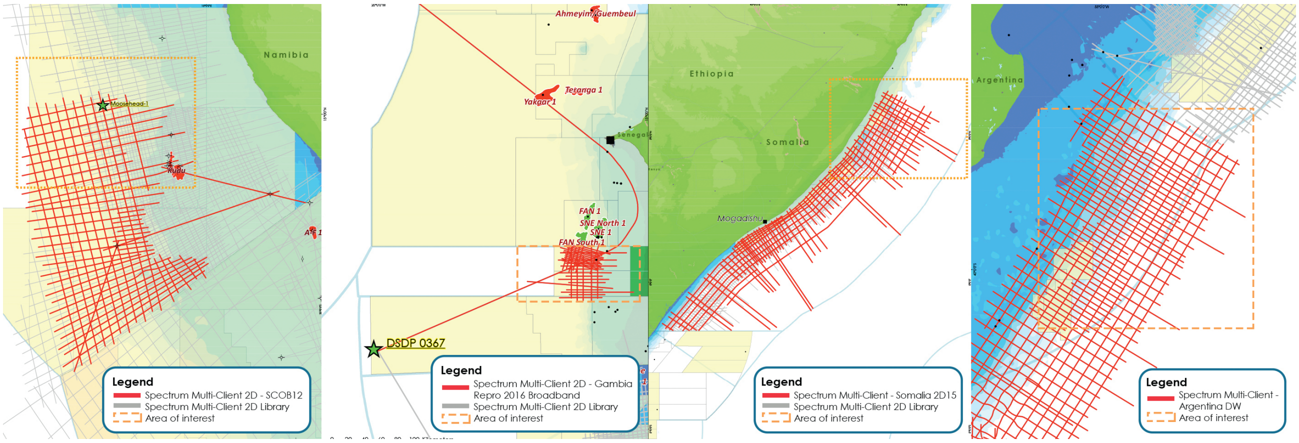

Figure 1 Spectrum 2D datasets assessed. 1) Namibia, SCOB-12-2D 2) The Gambia, The Gambia 2016 Broadband reprocessing project 3) Somalia, SOM15-2D 4) Argentina, Argentina-DW-2D.

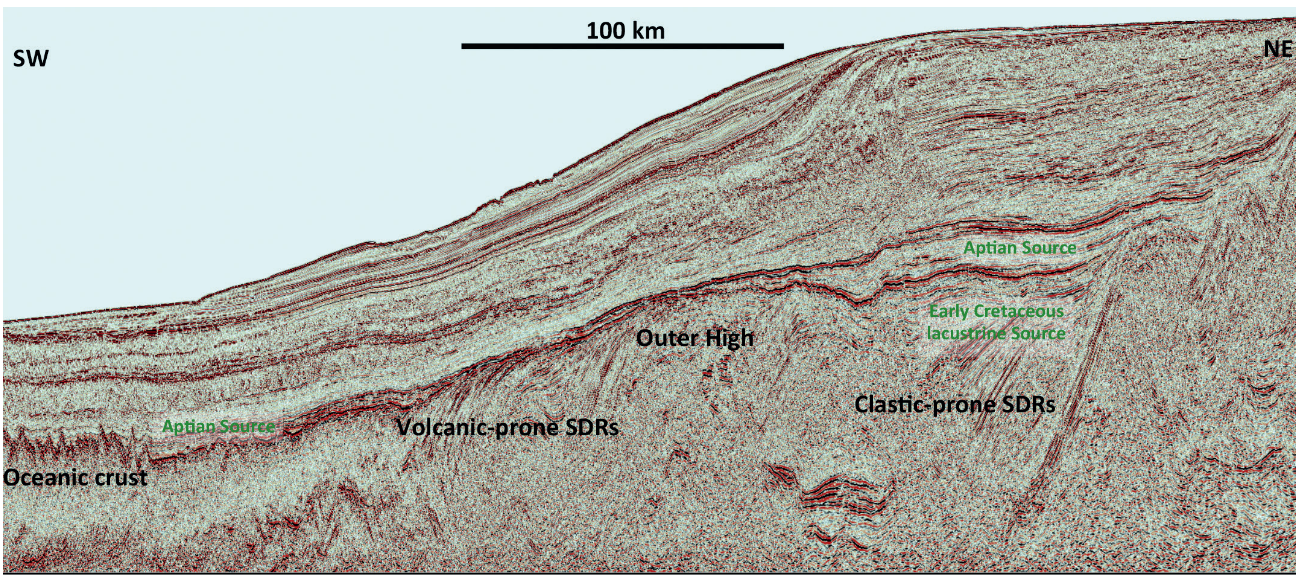

Figure 2 2D Seismic section from SCOB12-2D demonstrating the Barremian-Aptian Shale inboard and outboard components.

the giant Kudu gas discoveries and the offshore component of the marine shale was intersected at Moosehead-1, (See Figure 1-1) drilled by HRT in 2013 which encountered 197 m of the Barremian-Aptian Kudu Shale Fm (Figure 3) source rock, reported as ‘dark grey, high gamma organic shales with minor stringers of argillaceous limestone with increasing depth’ (Moosehead-1 Final well report). Source rock presence has also been derisked farther north in the Walvis basin by the Wingat-1 and Morombe-1 wells also drilled by HRT in 2013.

The SCOB-12 survey (Figure 1-1) was utilized in this study for the assessment of the offshore Namibian section of the Orange Basin. As well as being a regional dataset with well ties to both Moosehead-1 and Kudu field, it complies with the seismic data quality requirements specified by Løseth et al. (2011), i.e., zero phase, the far offset data is time aligned and the near and far amplitudes are properly scaled and matched for phase and frequency.

On seismic data, this source rock lies just above the break-up unconformity and has a distinctive opaque to semi-opaque low-frequency seismic character (Figures 2 and 3). Using additional regional data, this source rock can be mapped as regionally extensive, and is present from the Orange to the Walvis Basins.

No TOC% values were available for this study. However, using the Charsky and Herron (2013) methodology for calculating TOC% from bulk density, an inferred TOC% of ~10% is predicted locally at Moosehead-1 in the Barremian-Aptian Section. In Namibia on the SCOB12 survey, the Moosehead-1 well was utilized to calibrate the ‘Top Aptian Shale’ pick and other interpreted horizons. An example well cross section is displayed in Figure 3.

The low-frequency character of marine shales which had been initially observed was tested over candidate sources, using a frequency histogram (Figure 4) and by generating an ‘Average Frequency’ attribute. Frequency was found to be a key attribute to assist in the initial identification of candidate source rocks.

The top of the Aptian source rock is clearly associated with a decrease in acoustic impedance (‘soft kick’) for the Moosehead-1, Wingat-1, Murombe-1 and all 9 Kudu wells. AVO analysis tools (Hampson Russell) were used to calculate the amplitude versus offset response at the top source level, which show an amplitude dimming with increasing offset, considered to be an AVO class 4 anomaly (See Figure 8-1).

The amplitude at the top of the horizon was extracted to create a graph of amplitude vs CMP which displays the variation of amplitude along the top source horizon (Figure 9). In cases where a sufficient line density of 2D is available, the amplitude can also be gridded to show lateral variations of high and low amplitude which can be inferred to relate to TOC% changes. However, over regional seismic surveys the effect of acoustic impedance (AI) contrasts between the candidate source and

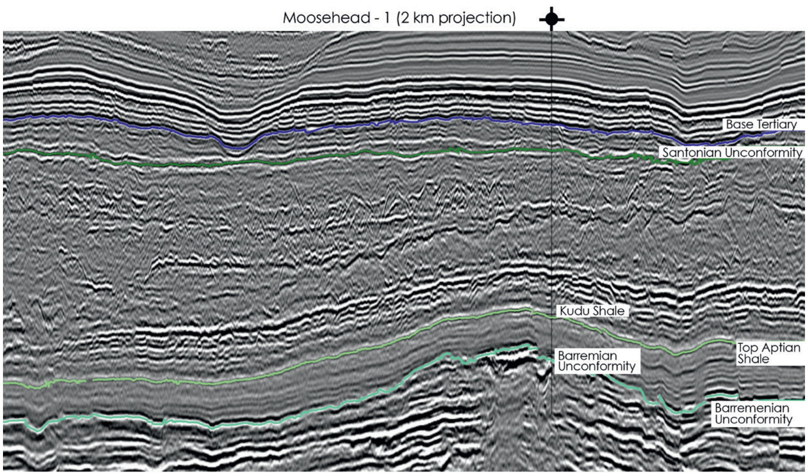

Figure 3 Moosehead-1, Top Barremian-Aptian (Kudu Shale) well tie projected to SCOB-12 seismic data.

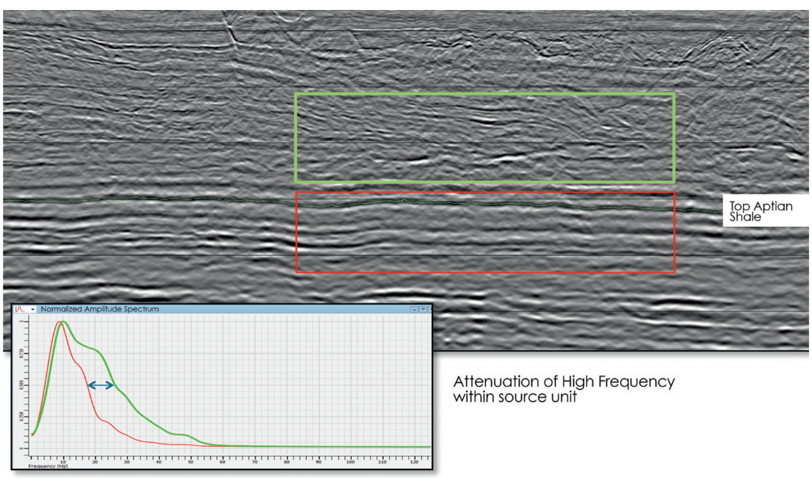

Figure 4 High-frequency attenuation within a marine shale source rock.

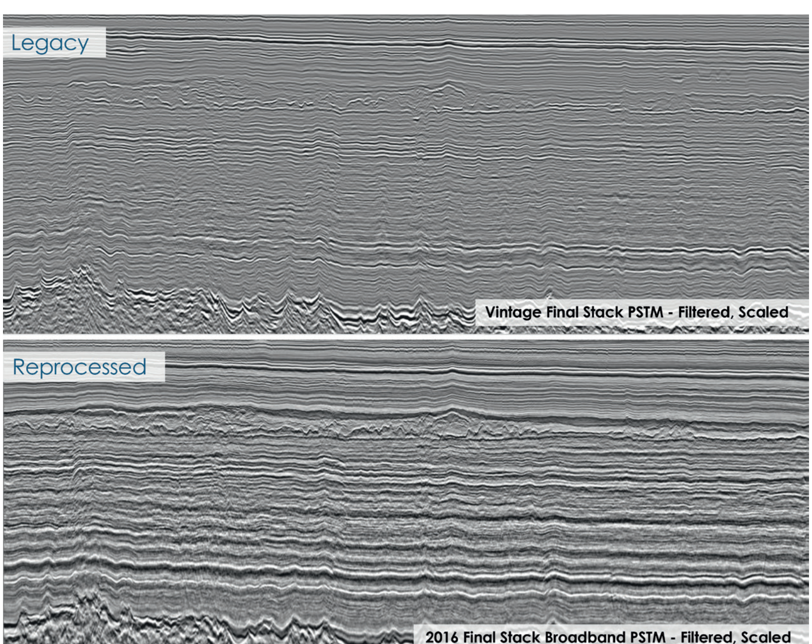

Figure 5 Legacy and reprocessed data offshore The Gambia.

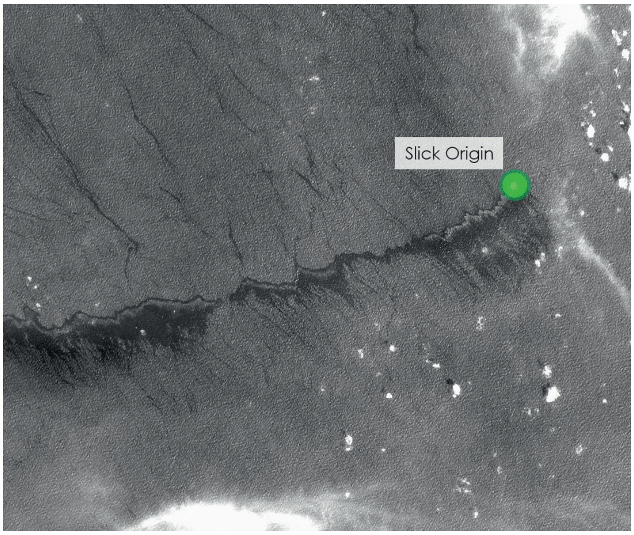

Figure 6 A Non-Anthropogenic sea surface slicks as catalogued in Spectrum's Somalia offshore interpretation report.

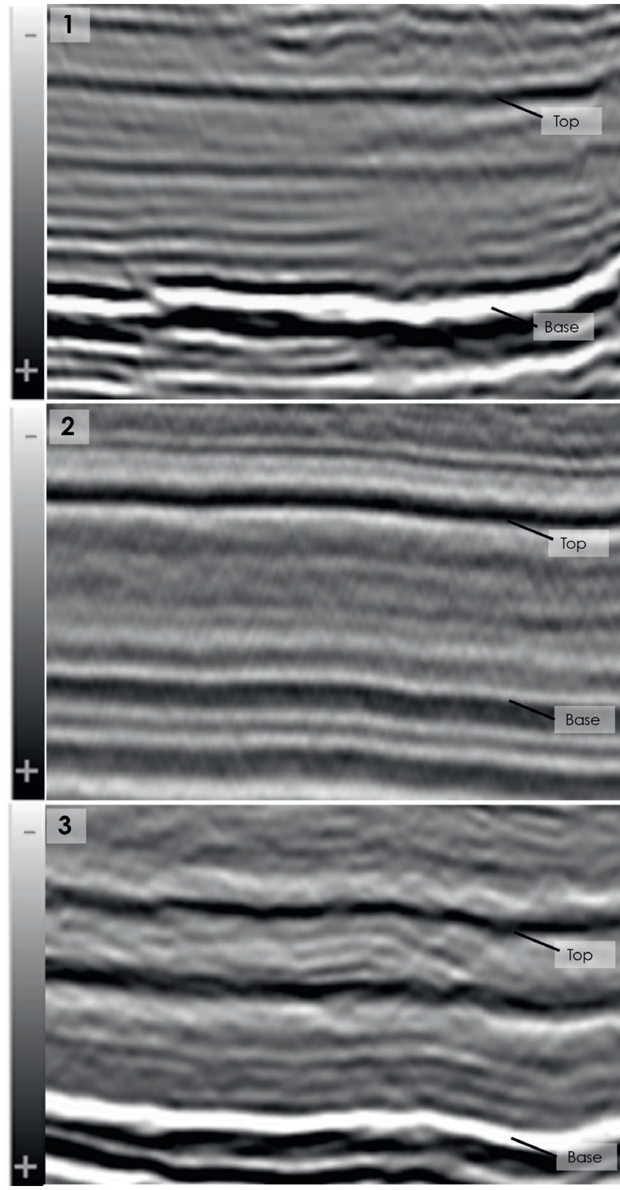

Figure 7 Top and base source horizons in SEG negative polarity. 1) Barremain-Aptian Shale, Namibia 2) Cenomanian-Turonian Black Shale, The Gamiba 3) Candiate Source A, Somalia.

embedding rocks is enhanced owing to regional changes in lithology.

Finally, the vertical amplitude profile was calculated at a suitable CMP which was observed to intersect the candidate source. The selected CMP and a subset of CMPS either side were extracted and the RMS average amplitude was calculated over the source interval (Figure 10). Although the variation in amplitude across the candidate unit should correlate to relative TOC%, owing to the loss of vertical resolution with depth, a long period RMS average was utilized which reduces the characterization potential of this latter criteria in this case.

The Gambia

Success at the FAN-1 and SNE-1 discoveries in neighbouring Senegal (Figure 1-2) has reduced source rock presence risk for on-trend deep-water hydrocarbon accumulations in neighbouring Gambia. The main regional marine sources are proposed to be Cenomanian-Turonian and Albian Marine Shales (Clayburn, 2018), the former of which is believed to correlate to the 'Black Shale' encountered in DSDP0367 which was estimated to have TOC% of 3-10%.

Spectrum's Gambia data has been recently reprocessed and now complies with data requirements for source rock characterization. Therefore, we could apply the geophysical criteria for source rock identification process proven in Namibia. An example of the difference in seismic data quality between vintage and reprocessed Gambia data is shown in Figure 5.

Low-frequency packages were initially identified as candidate source rocks. The top and base picks of these units were in turn refined using the criteria that 'that top and base of thick (>20 m) organic-rich claystones should be expressed by a significant reduction and increase in AI respectively'. Finally, the AVO response for each of the 'candidate' source rocks was tested. The most conclusive result is displayed in Figure 8-2.

Somalia

Somalia can be considered to be a true frontier margin with only two exploration wells drilled in <100 m water depth over the 1000 km-long margin. Based on a detailed regional geological evaluation of 40,000 km of 2D seismic data (Figure 1-3) acquired between 2014 and 2015, several 'candidate' source rocks were identified by predicted depositional environment and seismic character. 'Candidate source A' (Figure 7, 8, 9 and 10) is proposed to be a regionally extensive restricted marine shale, mapped within the Obbia basin of Northern Somalia.

Unlike The Gambia and Namibia, no well control or oil discovery exists to date to confirm the presence or test the maturity of the interpreted source horizons. In order to provide additional evidence for the presence of a hydrocarbon-producing source in addition to the Løseth et al. (2011) criteria and low-frequency character present at the inferred source interval on the seismic section, a sea-surface slick study was employed which identified more than 80 individual non-anthropogenic sea surface slicks along the length of offshore Somalia, an example of which is shown in Figure 6. Although typing the slick to a specific geological datum would require direct sampling, the presence of a significant quantity of slicks can imply the presence of at least one source which has reached maturity within the basin.

Source rock characterization in action

Criteria 1: The top and base of thick (<20 m) organic-rich claystones are expressed by a significant reduction and increase in AI respectively.

Løseth et al. suggest that the AI of good source rocks (TOC>3%-4%) is significantly lower than otherwise similar non-organic claystones (Løseth et al., 2011). When interpreting the top and base of the candidate source rocks in SEG negative seismic data, the top of the shale will be a 'soft kick' or a peak and the base as a 'hard kick' or a trough.

The base of the source rock in Figure 8, example 1 is interpreted as a 'hard kick'. From the well report of Moosehead-1, it is stated that the Barremian-Aptian shale source directly overlies the Lower Barremian limestone reservoir target. This limestone exhibits a higher AI than the overlying shale, therefore this increase in acoustic impedance would occur regardless of the high TOC% and resulting lower AI of the shale. Conversely, Figure 6, example 2 shows a weak hard kick at the base of the shale. It has been proposed that a second source rock of Albian age may exist beneath the Cenomanian-Turonian interpreted source. This unit cannot be calibrated on available seismic data as the unit was absent in the DSDP-0367 well. If, however, this source is present, and has a raised TOC% and therefore a low AI, then the low AI contrast at the base of this unit may be explained.

Criteria 2: The top of an organic-rich claystone will show a reduction in amplitude with increasing reflection angle at the top of the unit.

Organic-rich shales are often observed to be strongly anisotropic (Sayers, 2013) and anisotropy is expected to rise with increasing TOC%. In normal organic-rich claystones, the velocities are significantly higher parallel to the bedding than perpendicular (Vernik and Landis, 1996) which results in significant dimming in the far offset or angle stack. All three horizons show a dimming, with offset greater than the overall background trend, which may be categorised as an AVO class IV anomaly (Figure 8).

The presence of the dimming with offset in all three horizons would infer that the horizon pick in each represents the top of a shale with an elevated TOC%. This conclusion is supported by the bulk density calculation at Moosehead-1 and the recorded value TOC% value at DSDP0367.

Criteria 3: Assuming otherwise constant rock composition and consistent embedding rock properties, the amplitude at the top and base of the source unit will vary laterally, rising with increasing TOC%.

As the AI of a source rock is modelled to decrease relative to the increasing percentage of total organic carbon in otherwise homogeneous shale units (Løseth et al., 2011), the AI contrast and resulting seismic amplitude at the top of an interpreted source rock should be influenced in part by the rocks' TOC%. Other influencing factors in the amplitude response will include: the horizon falling below tuning thickness as well as variations in embedding rocks. No portions of the units mapped in Figure 10

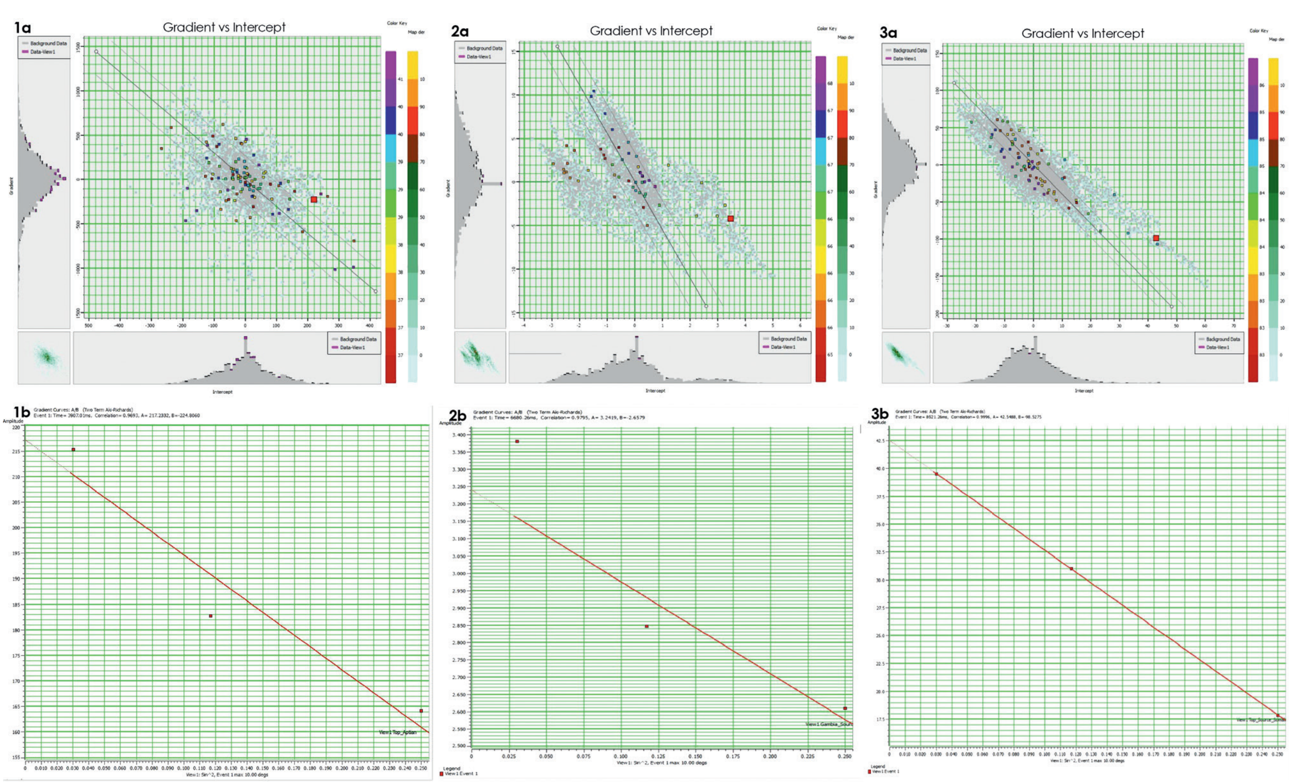

Figure 8 AVA crossplot (a) and gradient plot (b) for three source rocks. 1. Barremian-Aptian Shale, Namibia. 2. Cenomanian-Turonian Black Shale, The Gambia. 3. Candidate Marine Shale Source A, Somalia.

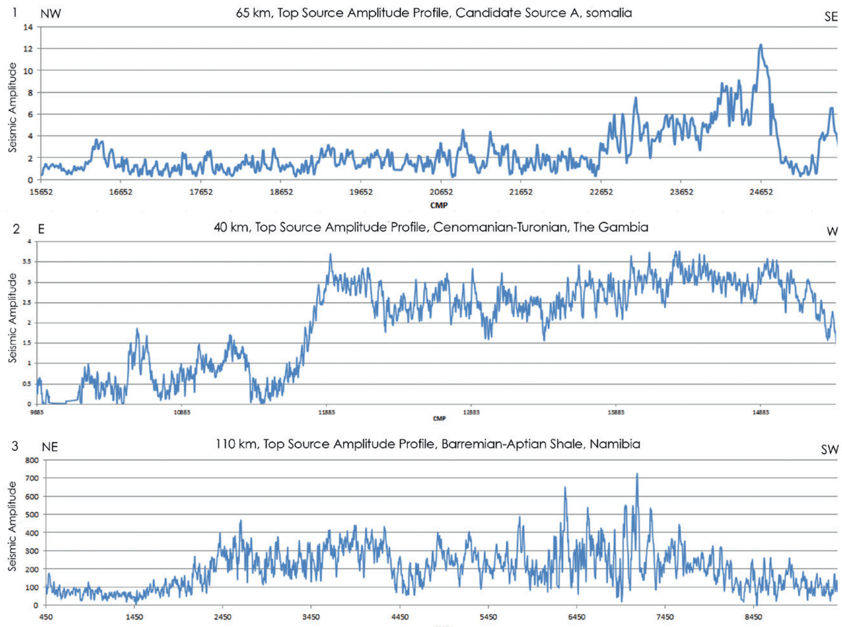

Figure 9 Horizontal Amplitude profiles along dip lines at the Top Source Horizon for three candidate source rocks. 1) Barremain-Aptian Shale, Namibia 2) Cenomanian-Turonian Black Shale, The Gambia 3) Candidate Source A, Somalia.

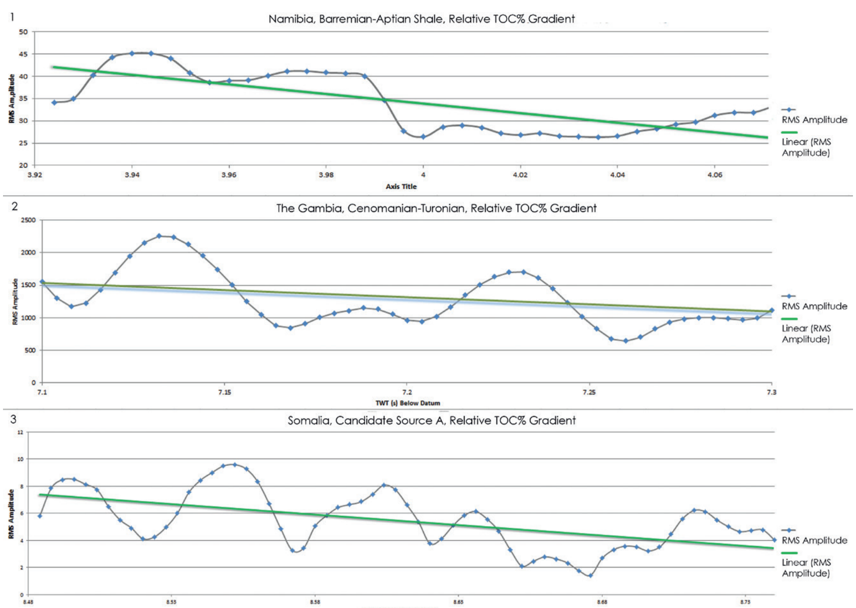

Figure 10 RMS Vertical Amplitude profiles from top to base source for three candidate source rocks. Linear trend line annotated in green. 1) Barremian-Aptian Shale, Namibia 2) Cenomanian-Turonian Black Shale, The Gambia 3) Candidate Source A, Somalia.

are below tuning thickness and no significant variations in lithology are expected over the sections mapped.

Assuming the amplitudes presented in Figure 10 are predominantly influenced by TOC%, we can see that in all three cases an increase in amplitude, with increasing distance from the shelf edge, is observed. Understanding the variation in apparent TOC% across the section requires an integrated approach in both mapping the termination of overlaying units (Løseth et al., 2011) as well as modelling of the compaction and thermal maturation of the source.

Criteria 4: The seismic amplitude response vertical profile should reflect the vertical TOC% profile over the source unit.

Figure 10 shows three vertical RMS seismic amplitude profiles from top to base interpreted source unit, averaged over a range of 5 CMPs. Each seismic stack has been corrected for spherical divergence and Q compensation and as such it is expected that any change in amplitude over the ~200ms section is expected to be geologically driven.

Each of these horizons is buried to around 4000 m, at which point a portion of the high-frequency component of the wavelet has been attenuated. As a result the dominant frequency at the target depth is insufficient to resolve small-scale variation in relative TOC%, and therefore only an overall trend (increasing or decreasing) is considered. As the TOC% curve is qualitatively related to the seismic response, each profile would imply that the formations exhibit a reduction in TOC% with depth, in a profile similar to the Spekk Formation TOC% curve as presented in Løseth et al. (2011).

A jump across the pond

Conjugate passive margins separated by continental drift may share key source rock stratigraphy. In Argentina the Argentine

Deep Water Basin is considered the geological conjugate to Namibia's Orange Basin (Figure 11), such that at the time of the deposition of the Barremian-Aptian shale, the proto-Atlantic is believed to have acted as a single restricted marine basin, with source preserving anoxic conditions enhanced by a period of global anoxia in the Early Aptian known as the ~120MA 'Selli Event'. As such, evidence collected on a derisked source can be used as evidence that the same source rock may be present in the conjugate margin. Having characterized the Aptian in Namibia, the same criteria were applied to the proposed Aptian section in the Argentine Basin (Figure 12). The Aptian in Argentina was found to display low frequency, have high amplitude top and base with soft and hard kicks respectively, and to display a reduction in amplitude with offset AVA. This confirms the likely presence of source rock in the Argentine Basin, critically derisking the charge system for the basin.

A bright amplitude package is observed lying directly over the characterized Aptian source rock. Detailed mapping revealed this anomaly (Figure 12) to be part of a very large confined channel complex influenced by drift currents, an analogue of the Sergipe Barra 3 BBO discovery, but three times larger. The derisking in this basin of 9 BBO by source rock characterization carried out in the conjugate margin therefore offers huge potential.

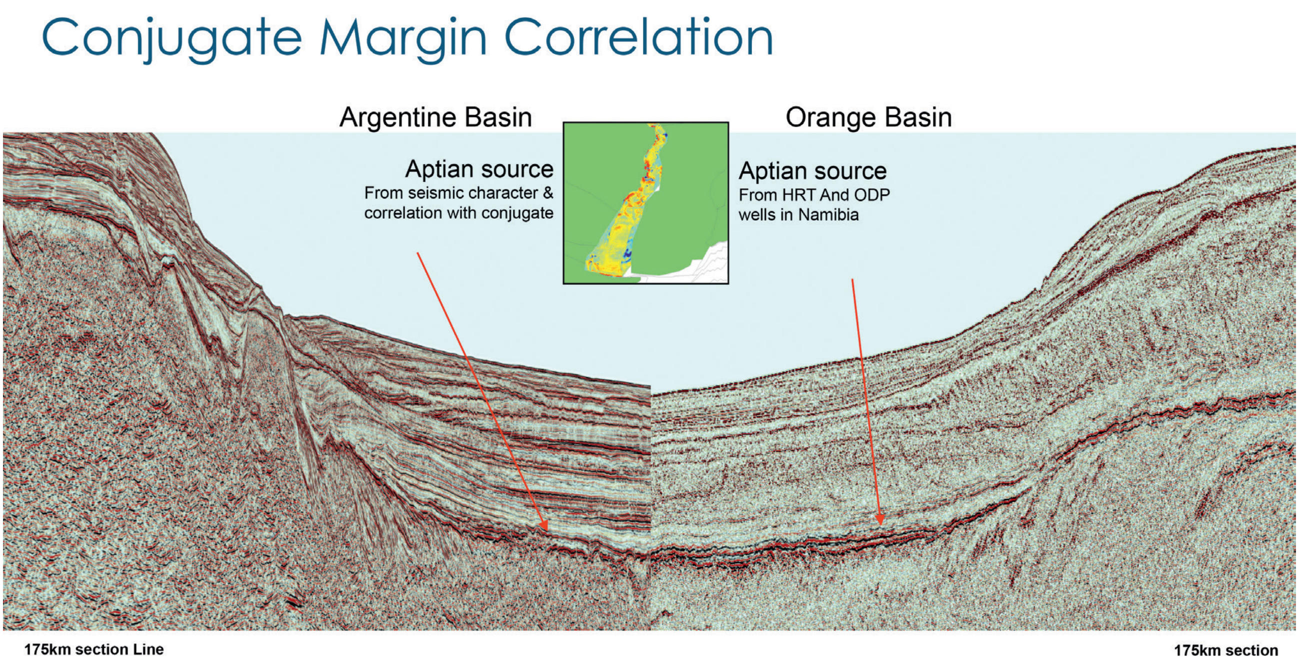

Figure 11 Conjugate margins adjusted for dynamic topography to correlate at top ocean crust ca 110 Ma.

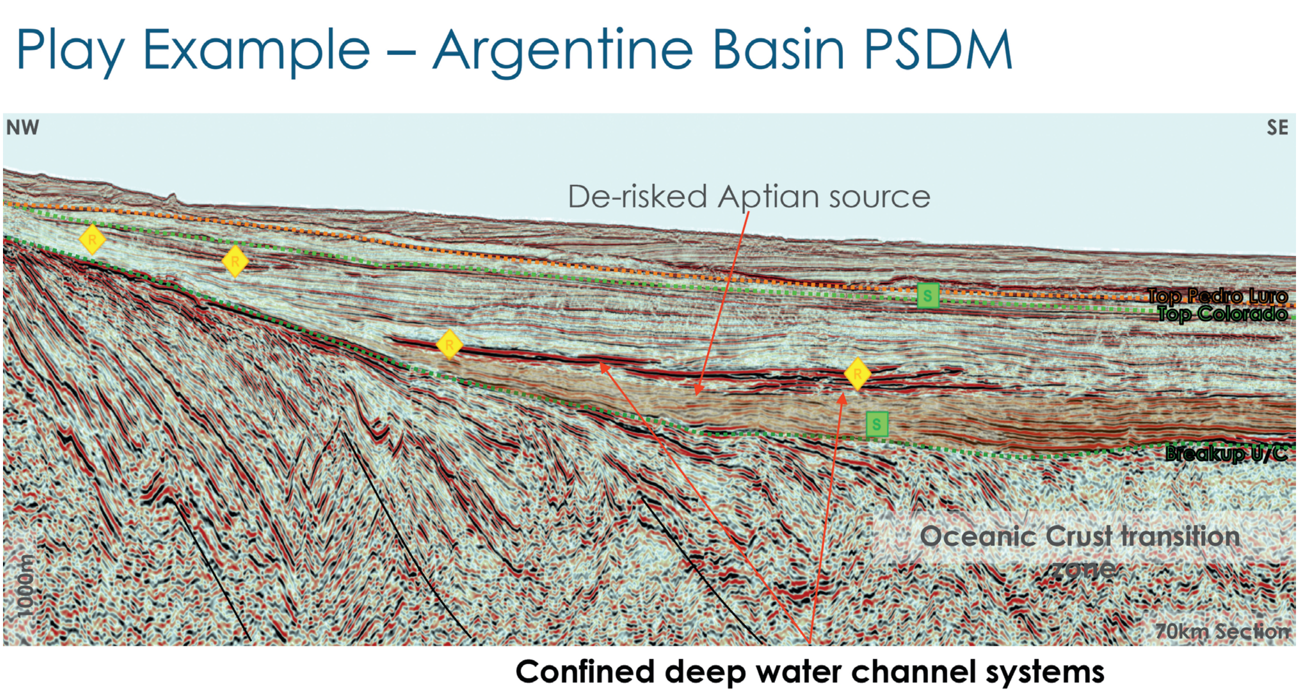

Figure 12 Detail of North Argentine basin and Aptian source rock.

Conclusions

The methodology and criteria applied in this study give interpreters a suite of tools by which they can make informed interpretations and conclusions as to the nature of an interpreted marine shale source rock. An expanded Løseth et al. (2011) methodology for the identification and characterization of marine shale source rocks is presented to include the following criteria:

1. Tectonic reconstruction of the basis should give reason to suggest a time period in which marine shale source rocks may be deposited and preserved
2. The 'candidate' source correlating to the geological age identified in point 1 will have opaque, bedded or low amplitude internal character.
3. The 'candidate' will be low frequency. Typically, the source unit will exhibit a reduction in frequency at the boundary with overlying rocks.
4. The top and base of the source will be represented by a reduction and increase in AI (soft and hard kick) respectively.
5. Dimming amplitude with offset (AVO class 4 anomaly) at the top source horizon
6. Assuming a homogenous source and bounding lithology, amplitude variation with depth and amplitude variation spatially will relate to relative TOC% change.
7. Implication that a source system within the basin has reached maturity for hydrocarbon generation can be inferred by the presence of sea surface slicks or seabed pockmarks.

The source rock is the first and foremost element in a play and the application of this methodology on a global scale will allow the identification, distribution and quality of source rock sequences to be carried out with confidence in frontier basins. Source rock characterization is likely to provide a key element to the derisking of plays in frontier basins.

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