Can hydrocarbon source rocks be identified on seismic data?

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ABSTRACT

Hydrocarbon source rocks contain significant volumes of organic matter, are capable of expelling petroleum when heated, and have produced most of the world’s known oil volumes. Recently, source rocks have also become recognized as unconventional economic reservoirs. Here we present a new way of identifying, characterizing, and mapping spatial distributions of organic-rich claystones that have produced most of the world’s known oil volumes. This has a significant impact on the prospect risk assessment of petroleum plays. Rock property studies of organic-rich claystones show that the acoustic impedance (AI), which is the product of compressional velocity and density, decreases nonlinearly with increasing total organic carbon (TOC) percent. Claystones mixed with low-density organic matter (TOC > 3%–4%) have significant lower AI and higher intrinsic anisotropy than otherwise similar nonorganic claystones. This gives the top and base source rock reflections characteristic negative and positive high amplitudes, respectively, which dim with increasing reflection angle. In addition, the TOC profile, which is a smoothed TOC percent curve, influences the top and base amplitude responses. An upward-increasing TOC profile has the highest amplitude at the top, while the opposite asymmetry is observed for downward-increasing TOC profiles. By using seismic data, we therefore can map lateral distribution, thickness, variation in TOC profiles, and, with local well calibration, convert AI data to TOC percent. This approach to mapping source rocks may change the way petroleum systems are evaluated.

INTRODUCTION

The petroleum system (Magoon and Dow, 1994) places the source rock as the first and foremost element of the geological system required to produce a petroleum play (Allen and Allen, 2005). Recently, source rocks have also become unconventional economic reservoirs. A source rock contains a significant volume of organic matter and is capable of expelling petroleum when heated. Source rock lithologies vary across a continuum from wholly organic sediments (coals), through siliciclastic shales and marls, to carbonates. This study focuses on organic-rich marine claystones that have produced most of the world’s known oil volumes (Klemme and Ulmishek, 1991). The ability to identify a source rock in the subsurface and quantify its distribution, thickness, and richness has a significant impact on prospect assessment and risk. Traditionally this is done by geochemical analyses of hydrocarbon source rocks, but well wireline data can also identify and give a good estimate of potential source rocks (Passey et al., 1990, 2010). However, such analyses only give local information. A remote sensing tool that examines the subsurface and maps the source rock basinwide would be a better means to reveal the hydrocarbon potential. In this paper we describe characteristic acoustic parameters of organic-rich claystones and associated seismic responses that allow their identification, characterization, and mapping on seismic data.

INFLUENCE OF ORGANIC MATTER ON ROCK PROPERTIES

The Late Jurassic Draupne (North Sea), Spekk (Norwegian Sea), and Hekkingen (Barents Sea) Formations on the Norwegian Margin and the Kimmeridge Clay in England are good examples of marine source rock claystones (Vollset and Døre, 1984; Dalland et al., 1988; Morgan-Bell et al., 2001; Keym et al., 2006). Such rocks typically comprise clay minerals (average 42%, minimum 20%, maximum 70%; density 2.65–2.70 g/cm³), silt-sized quartz and minor feldspar grains (average 39%, minimum 12%, maximum 62%; density 2.65 g/cm³), carbonate (average 5%, minimum 0%, maximum 41%; density 2.7–2.9 g/cm³), pyrite (average 13%, minimum 2%, maximum 26%; density 4.8–5.2 g/cm³), other (average 0.6%, minimum 0%, maximum 7%), and organic matter (3%–25% total organic carbon, TOC). Compared to surrounding nonorganic or low-organic claystones, the main difference is not the mineralogical composition but the higher content of organic matter. In normal to rich source rocks (TOC to 25%) the volume of organic matter is approximately twice the TOC percent, which is measured in weight, because the density of kerogen (1.1–1.4 g/cm³) (Passey et al., 2010) is roughly half the density of the mineral mass (2.7 g/cm³). The density of kerogen is also very low in oil and gas mature source rocks due to as much as 50% internal kerogen porosity (Sondergeld et al., 2010). How this organic matter influences the seismic response is described by the acoustic parameters: compressional velocity (Vp), shear velocity (Vs), bulk density, anisotropy, and attenuation. Our studies of cores and well logs show that the acoustic impedance (AI), which is the product of compressional velocity and density, decreases nonlinearly with increasing TOC percent (Fig. 1). Therefore,

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Figure 1. A: Total organic carbon (TOC) weight percent versus acoustic impedance (AI) plot for Metherhills Quarry well in Kimmeridge Clay in southern England (Morgan-Bell et al., 2001). Maximum burial is ~1.5 km. TOC percent is based on geochemical analyses of core samples. B: Similar plot for Hekkingen Formation, Barents Sea, from 9 wells at depths between 1700 m and 2500 m. Maximum burial was ~1 km deeper. TOC percent is based on geochemical analyses of samples of cuttings. Dotted curve in A, which shows nonlinear AI increase with increasing TOC percent, is shifted ~1000 AI units up to fit with deeper (~1–2 km) buried Hekkingen Formation.
the AI of good source rocks (TOC > 3%–4%) is significantly lower than in otherwise similar nonorganic claystones. The AI of source rocks is also significantly lower than in most other rock types. The AI contrast between nonorganic and organic-rich claystones remains stable with depth down to 4500 m, i.e., oil mature source rock (Fig. 2). The top and base of thick (>20 m) organic-rich claystones are therefore expressed by a significant reduction and increase in AI, respectively.

Together the Vp/Vs and the anisotropy contrasts at a rock interface determine the amount of amplitude variation with incidence angle (AVA) for a reflected seismic wave (Thomsen, 1993). The intrinsic anisotropy rises with increasing TOC percent, and in normal organic-rich claystones (TOC >3%–4% and <25%) the velocities are significantly higher parallel to the bedding than perpendicular to the bedding (Vernik and Landis, 1996; Sondergeld et al., 2000). The compressional velocity in organic-rich claystones therefore rises with increasing deviation angle of the wells (Hornby et al., 2003). As in the epoxy and glass experiment by Melia and Carlson (1984), we assume that mixed layered aggregates of acoustic soft organic matter and acoustic harder minerals cause the strong intrinsic anisotropy. Interbedded centimeter to meter thick beds of variable organic content (e.g., as in the Kimmeridge Clay Formation; Morgan-Bell et al., 2001) may give additional anisotropy on seismic scales (tens of meters). Calculating the AVA response at the top source rock reflection from an isotropic model, which only considers the AI and Vp/Vs ratio, normally only gives a weak dimming with offset. The dimming increases significantly if the intrinsic anisotropy is added. Such clear dimming was found in our studies of top source rock reflections (e.g., Fig. 3). Theoretical models also reveal significant dimming with offset (Carcione, 2001). We define the significant drop in AI together with the clear dimming of amplitude with offset as a characteristic top source rock behavior (i.e., AVO class 4 seismic response) (Castagna and Swan, 1997). A source rock interval that is thicker than ~20 m (above tuning thickness) will also have a distinct base source rock reflection. The increase in AI at the base gives a high-amplitude positive reflection that also dims with offset, i.e., an AVO class 1 response. Generally, distinct AVO class 4 reflections are not very common. Coal, which is a source rock, has this type of reflection. We have locally identified both shallow buried top sands and some top claystone reflections with AVO class 4 responses. Compared to top source rock reflections, these reflections have weaker amplitudes and smaller AVA dimming. Top sand reflections also have restricted basinwide distribution compared to source rocks. However, we have not studied all rock types and therefore cannot rule out that there may also be other lithological boundaries with high-amplitude AVO class 4 reflections.

**SEISMIC DATA QUALITY**

In order to confidently interpret seismic amplitudes and changes in amplitude with offset, the phase of the data must be known, the near and far offset data must be time aligned, and the near and far amplitudes should be properly scaled and matched for phase and frequency. The seismic sections presented here are zero phased. A black-blue peak reflection represents an increase in AI, whereas a red-yellow trough represents a reduction in AI.

**SEISMIC EXPRESSION OF SOURCE ROCK**

This study shows that reflections from rich (>3%–4% TOC) and thick (>20 m) source rocks have very high amplitudes compared to most surrounding reflections. Top and base source rock reflections are therefore easily identified on seismic sections. Generally, the amplitudes from the source rock interfaces rise with increasing organic content (Fig. 1), assuming that there is otherwise uniform source rock composition and there are only small variations in the embedding rocks. This is correct as long as the source rocks are thicker than the tuning thickness (Widess, 1973). Marro-
Interpreting the Source Rock Interval

Lateral variations in amplitude from top and/or base source rock layers can reflect basinwide shifts in thickness, variations in organic concentrations, changes in TOC percent profiles, and/or changes in embedding rocks. Changes in embedding rocks are not discussed in detail here, but onlapping and truncating reflections should be mapped and correlated with shifts in amplitude. We find it useful to first map the source rock thickness by interpreting top and base source rock reflections. Second, amplitude variations of both the top and base source rock reflections are extracted. Areas where the source rock interval decreases to less than the tuning thickness are correlated to the reduced amplitude strength of the top source rock reflection (Fig. 4). A uniform increase or decrease in both top and base source rock reflections that does not correlate with thickness variations may reflect the average TOC percent increase or decrease, respectively. Where the top source rock reflection has a higher amplitude than the base, or vice versa, this can be linked to asymmetric organic profiles, as seen for the Spekk and Hekkingen Formations (Fig. 5). Lateral asymmetric top and base source rock reflections variations may reflect shifts in organic profiles. Variations in intra-source rock reflection pattern should be analyzed where the source rock interval is thick.

A nonlinear correlation between AI and TOC percent is found (Fig. 1). If seismic data are inverted to AI data it is possible to transform the AI values in the source rock formation to TOC percent values. However, such AI to TOC percent conversion requires good local seismic to well calibrations both to invert the seismic data and to establish a local AI to TOC percent relation (Fig. 6).

Loseth et al. (2011) showed that thin-skinned gravitational gliding structures that are large enough to be imaged on seismic data commonly occur in organic-rich claystones. They are characteristic but not unique for this rock type. In addition to the acoustic characteristics, the seismic identification of layer-bound thin-skinned gravitational gliding structures may increase the confidence in identifying organic-rich claystones.

CONCLUSIONS

Among the data types available today, the subsurface is best imaged with seismic data, and we have demonstrated that organic-rich claystones have characteristic seismic responses that allow identification. Mixing kerogen into claystones gives a significant nonlinear reduction

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**Figure 4. Source rock thicknesses in meters from wells. A: Near trace seismic data. B: Top source rock maximum trough amplitude map.**

-for thicknesses ~20 m, amplitude dims significantly westward to crest of footwall where well penetrated 2.5-m-thick source rock.

-for thicknesses <-10 m, top source rock reflection becomes weak, and below 5 m there is no obvious top source rock reflection. No relationship between thickness and top source rock amplitudes is observed where source rock is thicker than tuning thickness. A–A’ shows line of seismic section.

**Figure 5. Density log (RHOB, g/cm³), total organic carbon (TOC) log (0–20 wt%) (Passey et al. 1990) (for B only), TOC profile, and near trace seismic section. A: Spekk Formation in Norwegian Sea. B: Hekkingen Formation in Barents Sea. Smoothed TOC profile correlates with seismic response such that upward-increasing TOC profile A has highest amplitude at top, while downward-increasing TOC profile B has highest amplitude at base. TOC profiles explain why the base Cretaceous unconformity (common name for top source rock reflection, offshore Norway), has high amplitude in North Sea and Norwegian Sea but low amplitude in Barents Sea. Color code and scales are same for both sections.
in AI with increasing TOC percent. Top reflections from good source rock intervals (TOC > 3%–4%) therefore have high amplitudes. Layered aggregates of organic matter cause strong intrinsic anisotropy that results in a significant dimming of top and base source rock reflections from the near to the far offset. An organic-rich (TOC > 3%–4%) and thick (>20 m) claystone therefore has a negative top response reflection that dims with offset, while the base has a positive response that also dims with offset. In addition to the average organic content, the vertical stacking of the organic content, which we smooth and call the TOC profile, also influences the seismic response. Typical TOC profiles, where the amount of organic matter increases or decreases upward, are seen in the main source rocks in the North Sea (Draupne Formation) and Barents Sea (Hekkingen Sea), respectively. The different TOC profiles explain why the Hekkingen Formation, which is richer in organic matter than the Draupne Formation, has weaker top but stronger base amplitude reflections. Based on the established characteristics, the source rock presence, thickness, and basinwide variations in organic content can be mapped using seismic data. Seismic AI data from the source rock interval can be transformed to TOC percent values where good local well calibration can be obtained. We believe that the findings from this study will change the way petroleum systems are evaluated in basin analysis studies.

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Figure 6. A: Seismic section 12 September 2019 by guest Downloaded from https://pubs.geoscienceworld.org/gsa/geology/article-pdf/39/12/1167/3540214/1167.pdf