Scale effects on modelling the seismic signature of gas: results from an outcrop analogue

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ABSTRACT

Numerous examples of reservoir fields from continental and marine environments involve thin-bedded geology, yet, the inter-relationship between thin-bedded geology, fluid flow and seismic wave propagation is poorly understood. In this paper, we explore the 4D seismic signature due to saturation changes of gas within thin layers, and address the challenge of identifying the relevant scales and properties, which correctly define the geology, fluid flow and seismic wave propagation in the field. Based on the study of an outcrop analogue for a thin-bedded turbidite, we model the time-lapse seismic response to fluid saturation changes.
for different levels of model scale, and explore discrepancies in quantitative seismic attributes caused by upscaling. Our model reflects the geological complexity associated with thin-bedded turbidites, and its coupling to fluid flow, which in turn affects the gas saturation distribution in space, and its time-lapse seismic imprint. Rock matrix and fluid properties are modelled after selected fields to reproduce representative field models with realistic impedance contrasts. In addition, seismic modelling includes multiples, in order to assess their contribution in seismic propagation through thin gas layers. Our results show that multiples could contribute significantly to the measured amplitudes in the case of thin-bedded geology. This suggests that forward/inverse modelling involving the flow simulation and seismic domains used in time-lapse seismic interpretation should account for thin layers, when these are present in the geological setting.

Keywords: Time lapse, Gas, 4D Seismic Attributes

1 INTRODUCTION

Thin-bedded deposits constitute an important fraction of reservoirs in continental and marine environments, such as aeolian, fluvial, deep water clastics, and shallow marine (e.g. Lalande, 2003). Notably, enhanced logging which aims at identifying the presence of thin beds can result in an increase of calculated reserves of up to 60%. One of the challenges for 4D seismic as a reservoir management tool is to evaluate hydrocarbon-bearing thin beds of thickness which could be well-below the seismic resolution, especially gas-bearing, which entail distinct elastic properties. Overall, the influence of scale has been widely studied in the seismic context as well as in the petroleum engineering context, but to our knowledge, the inter-relationship between thin-bedded geology, fluid flow and seismic wave propagation is not well understood (Mangriotis and MacBeth, 2015). In the literature across the disciplines
of geology, geophysics and petroleum engineering, there is an overall inconsistency of scale in the definition of thin beds, namely ‘thin’ can range from centimetres (from thin bed analysis logging data), to several metres (from seismic data), to tens of metres (with regards to reservoir fluid flow) (Pickup and Hern, 2002). This fact reflects that there is a characteristic scale below which it is unpractical to model thin beds, because of measurement limitation uncertainties, as well as the complexity involved, which is different for each discipline. Nonetheless, in reservoir management, there are recognized benefits to merge geological, fluid flow, and seismic models; in the case of time-lapse monitoring, 4D seismic data reflects changes in seismic properties due to pore pressure, fluid saturation, temperature and also layer thickness in the presence of compacting reservoirs. To model the seismic signature of gas in thin bedded geology in a time-lapse sense, one needs to connect the domains of fluid flow simulation to seismic, a process that is termed simulator-to-seismic modelling (Amini, 2014), and ensure that the models in these two domains capture the effects of thin bedded geology that may influence the 4D seismic signal. In this work, by thin, we consider the bed thicknesses, which are potentially below seismic resolution, but still give rise to a 4D seismic signature.

From a logging perspective, enhanced logging and interpretation methods have made the task of thin-bed analysis more manageable in the centimetre scale, which involves increasing levels of accuracy in Net-to-Gross (NTG ), which is defined as the fractional volume of sand, porosity, saturation and Stock-Tank-Oil-Initially-In- Place (STOIP) estimates, which is the volume of oil in a reservoir prior to production (Anijekwu et al., 2012). On the other hand, reservoir fluid flow simulation models, generally span much coarser grids, typically tens to hundreds of meters, with high-resolution models in the order of 10m laterally and 0.1m vertically (Agada et al., 2014). The obvious reason for coarse fluid flow models is
computational limitations, as well as a means to manage the uncertainty through the averaging process, due to imperfect characterization at the fine scale. The process of upscaling aims at averaging static and dynamic reservoir properties, rendering flow simulations more computationally manageable, but upscaling itself is challenging and in some cases problematic. Specifically, (a) small scale heterogeneity needs to be accounted for in capillary pressure estimation (Stephen et al., 2002), (b) heterogeneity entails preferential fluid-flow pathways which are important to reservoir volumetrics and flow (Falivene et al., 2006) and (c) the fluid bulk modulus ($K_f$) cannot be upscaled for gas as the fluid saturation can be heterogeneous (Sengupta, 2000; Kristetter et al., 2006; Castro and Caers, 2005; Falahat, 2012), a condition commonly referred to as heterogeneous or ‘patchy’ saturation.

The seismic behaviour of thin beds was originally analysed in terms of resolution capabilities, namely the ability to detect separate reflection events from the top and bottom interfaces defining the thin layer: Widess (1973) devised a simple $\lambda/8$ rule for the case of a higher impedance layer within a homogeneous medium, $\lambda$ being the dominant seismic wavelength. Ever since, seismic resolution below tuning thickness has become possible using spectral inversion, both post-stack and pre-stack (ex Portniaguine and Castagna, 2005; Rubino and Velis, 2011), advanced data conditioning techniques such as structurally oriented noise filtering, and spectral enhancement, and use of more sophisticated seismic attributes (as shown by Henning and Paton, 2011: http://www.geoteric.com/hubfs/uploads/downloads/GCSSEPM_2011_ThinBeds.pdf), as well as smart reflectivity inversion algorithms (Thore and Spindler, 2013). Below seismic resolution, several studies suggest that heterogeneity at a scale below the seismic resolution still influences the seismic response (e.g. Mukerji and Mavko, 2008; Dejtrakulwong et al., 2010). Addressing dispersion and attenuation caused by stratigraphic filtering, O’Doherty and
Anstey (1971) showed that intra-bed multiples are key contributors to the seismic signature, with multiples interfering constructively or destructively to primary reflections for the case of a cyclic and transitional sequence, respectively. Stovas and Ursin (2007) for a binary medium with weak reflectivity contrast define three different regions with distinct seismic signatures based on the ratio of dominant seismic wavelength to layer thickness ($\lambda/d$): (a) an effective medium zone, (b) a resonance medium zone, where multiples become pronounced, and (c) a time-average medium zone. Moreover, they show that the critical $\lambda/d$ depends on the reflectivity itself, with critical $\lambda/d=4$ for weak reflectivity contrast, which suggests that above this critical ratio, Backus averaging (Backus, 1962) is appropriate to define the effective medium properties. In a similar mind-frame, but for strong heterogeneity, Liu and Schmitt (2003) modelled the response of a binary medium, and observed a transition to effective medium for larger ratios ($\lambda/d\sim10$). Dejtrakulwong et al. (2010) show a promising statistical analysis of sub-resolution synthetic sand-shale reservoirs with $\lambda/d\sim100$, and show that it may be possible to distinguish between different NTG and saturations in the wavelet-transform-based attribute space. Furthermore, Stovas et al. (2006) suggests that inclusion of sedimentological processes at the sub-seismic scale might lead to more realistic modelling of the AVO-attributes. All these aforementioned studies suggest that the seismic behaviour across a stack of thin layers is largely case-dependent and involves complex interference effects related to layer thickness, impedance contrasts and seismic source characteristics (i.e. dominant frequency).

In the case of 4D, the aim is to assess seismic differences due to fluid flow leading to saturation and pressure changes. Even though seismic may not be able to resolve zones of saturation change if they are at sub-seismic resolution, it may still detect them as those affect velocity and density, as shown in Mukerji and Mavko (1998), Sengupta (2000) and Castro
Coarse scale saturations from flow simulation may represent smoother saturation zones, or simply no change in saturation in areas where saturation changes should be present and consequently affect 4D seismic, had the flow simulation been at the correct scale (Castro and Caers, 2005). Moreover, the primary wave and short-period multiples, where short-period denotes multiples arriving within the duration of the propagating wavelet, may interfere strongly (e.g. Mangriotis et al., 2013) thereby affecting amplitudes in both static (3D) and dynamic (4D) sense.

In this study, the aim is to quantify 4D seismic gas signature in the presence of thin-bedded geology. To this end, it is key to capture both the relevant scale of the problem, in terms of the field dimensions and the laminae scale, which depends on the depositional environment, as well as to correctly model initial rock and fluid properties, and the evolving pressure and saturation conditions representative of the field development. For our model to be credible, we consider a realistic geological model for a turbidite, which is based on an outcrop analogue. We assess rock properties based on two different field cases, and consider fluid saturation changes assuming Gassmann fluid substitution (Gassmann, 1951). The fluid saturation changes correspond to specific scenarios that have been encountered in these two field cases, involving pre-production, several stages of pressure depletion as well as a gas injection scenario. In terms of seismic wave modelling, we only consider elastic wave propagation and ignore fluid flow induced by mesoscopic heterogeneities, which would lead to attenuation. Our seismic modelling is based on the Kennett algorithm (Kennett, 1983), which can capture the effects from multiples and converted waves. As flow simulation typically involves coarse grids, we also investigate how the process of upscaling for fluid flow may degrade the 4D seismic attributes by comparing fine and upscaled fluid and synthetic seismic models.
2 MODELLING SCALE EFFECTS

2.1 Outcrop Analogue and Field Cases

Outcrop analogues have been used for decades to understand the geobody distributions in reservoirs (for a detailed review of historical application of outcrop analogues, please refer to Howell et al., 2015). Quantification of the geometry of the genetic units, which are the sedimentary building blocks, is measured directly from the outcrops, and is later used to populate and condition the stochastic reservoir models (Howell et al, 2015). Seismic modelling of outcrop analogues enables a comparison between the facies distributions observed in the outcrops and their subsurface counterparts. The selected outcrop for this study, Ainsa II, comes from the deep-marine Ainsa Channel System in south-central Pyrenees in Spain, which consists of two principal channel complexes (Ainsa I and Ainsa II) separated by thin sandy turbidites and marls (Clark, 1995). As noted by Bakke et al. (2008), who performed seismic modelling for this outcrop, the facies distribution and large-scale geometry of the Ainsa II outcrop resembles depositional elements observed in the turbidite system offshore Angola. The Ainsa II Channel Complex has been interpreted, digitized and modelled by the Genetic Unit (GUP, Heriot-Watt University). Based on paleocurrent data measured by Clark (1995) and GUP, five different channel bases were digitized, eroded areas were restored and probable channel tops were assigned (Barreto, 2008). Both the channel and facies modelling was developed deterministically, with different facies were identified: sand, shale and debris flow, sand and shale being the most dominant facies of the three (Barreto, 2008). Figure 1 shows the digitized 2D model used in this study (which is 750m wide and 50m deep, and consist of cells of 0.25m vertically and 0.3m horizontally) displayed against the outcrop’s photopanel.
To emulate realistic reservoir field conditions and assess the sensitivity of 4D seismic to different field characteristics, we considered two turbidite field cases, from the North Sea and West Africa, which are part of the Edinburgh Time-Lapse Project consortium database, consisting of field logs, reservoir fluid flow simulation models and time-lapse seismic datasets. The first field case is a deepwater offshore oil and gas reservoir in the North Sea corresponding to a live black oil accumulation with small local gas caps. Similarly to the first case, the reservoir pressure is close to the oil bubble point (approximately over by 5 bars) and to preserve pressure during production, a down-dip water injection plan was developed. The available data for this field include 35 wells with well log data, coarse and fine reservoir simulation models and four seismic surveys. The turbidite geology is a result of firstly, a rifting regime during the Late Cretaceous-Paleocene, with the North Atlantic sea-floor spreading axis propagating into the Norwegian Greenland Sea (Ziegler, 1988) and secondly the induced extension generating normal faults and associated subsidence. During the Paleocene, clastic sediments (mostly sands) and pelagic sediments (clays) were deposited in deep marine conditions as stacked turbidite channels, which constitute the reservoir facies for this field. The second field case considered is a West Africa Tertiary deepwater reservoir, with high gas-oil ratio and pressure close to (roughly 10 bars above) its oil bubble point. To support field pressure and avoid gas exsolution, the production plan included water down-dip injection and gas injection through its top structure. The available data for this field case included 14 wells with wireline logs, the reservoir flow simulation model which was history matched to the production data and three seismic volumes (baseline and two monitors). The geology of the region is characterized by an extensive turbidite fan system which was deposited in the Oligocene during a period of high sediment influx caused by the uplift of the African continent. More specifically, the field considered corresponds to the mid-distal
deposits of an unconsolidated turbidite reservoir, consisting of a stacked complex of several classical turbidite channel-levee sequences (Roggero et al., 2012).

In turbidite reservoirs the geological architecture is a combination of deposits corresponding to a low energy deep marine environment, with the occasional high energy influx of sediments carried by the turbidite flows from the platform. The stratigraphy of the sequences include interbedded fine sand, silt and shale at the base to coarse and very clean high porosity channel sands at the top.

2.2 Petro-elastic Modelling

The petro-elastic model links rock and fluid properties to elastic moduli, and in turn determines seismic impedances; in a general sense, the petro-elastic model considers the effects of saturation and pore pressure variations, and the static parameters (porosity and net-to-gross) (Amini, 2014). The petro-elastic model should thus describe the rock frame, both statically as well as in response to pressure changes, and the fluid components as a function of pressure, temperature and salinity. There are numerous petro-elastic model formulations in the literature (the reader is referred to Mavko et al., 2009 for a review of petro-elastic models). As shown by Briceño et al. (2016) there is no single ‘best’ petro-elastic model, with most models being comparable, if calibrated properly. The selected petro-elastic model is one of the paradigms presented by Briceño (2017), for a sand-shale system using well-logs and laboratory measurements, which, in summary, involves i) mixing before fluid substitution through Voigt-Reuss-Hill averaging for the rock matrix moduli (Mavko et al., 2009), ii) a porosity dependence of the dry frame moduli based on the consolidation factor from Lee (2005), iii) dynamic dependence of the dry frame moduli on pressure through MacBeth (2004), iv) dynamic fluid moduli dependence through Batzle and Wang (1992), v) harmonic
average to compute the fluid bulk moduli (Domenico, 1974), and finally vi) Gassmann fluid substitution (Gassmann, 1951). The details of this petro-elastic model are discussed in Appendix A.

The stratigraphy of the West Africa field can be defined as coarsening upwards, ranging from interbedded fine sand, silt and shale at the base to coarse and very clean channel sands at the top, with high porosities between 27 and 30% and permeabilities as high as 5 Darcy. The notoriously low density (between 2 and 2.2 g/cc) of the shaly intervals in this field suggests the presence of a mineral component with a density much lower than the typical quartz-feldspar-illite range (Rangel, 2016). The lighter material corresponds to kaolinite, which is abundant in areas under tropical weather, where the process of denudation and weathering of pre-existing rocks generates a larger proportion of kaolinite over other types of clay. The reservoir heterogeneity of this field in the fluid flow simulation model was expressed in terms of saturation regions, which were used to define the static flow simulation properties. We populate the binary (sand/clay) outcrop analogue with properties from two characteristic saturation regions defined by Rangel (2016), namely a ‘dirty sand’ and a ‘dirty clay’ whose properties are shown in Table 1; these values are reported as ‘matrix’ values. The North Sea field consists of stacked turbidite channels with good reservoir quality and sands with porosities between 25 -30% and permeabilities between 200-1000 mD (Rangel, 2016). The mineral shale density suggests a mixture of clays, due the geographical location (high latitude) with the dominant clay generation process corresponding to illite and chlorite. In addition to these two types of clays, shales from this field also contain montmorillonite originating from the weathering of volcanic material, resulting in a mixed composition for the clay fraction of the shales. The fluid flow simulation model cells are described by a net-to-gross NTG (or volume of shale VSH = 1-NTG), which assumes that the geology variations
can be represented by introducing varying sand/shale fractions within the sand bodies (Briceño, 2017). The sand and shale properties for this field were estimated by Briceño (2017) through well-log calibration and are reported as single constituent values (cleanest sand and purest shale) in Table 1. Other field parameters that are used in rock and fluid properties’ estimation (Appendix A) are summarized in Table 2. The parameters used in the PEM for both the N. Sea and W. Africa examples were obtained from well log calibration fits to several wells that were available for each field. Cross-validation, whereby the optimization was tested on a subset of the wells versus the full set, confirmed the robustness of this approach (Rangel, 2016; Briceño 2017).

2.3 Saturation and Pressure Scenarios

For a water-driven oil and gas reservoir, the key parameters that determine the relative saturations of oil, water and gas are: the irreducible water saturation ($S_{wirr}$), the critical gas saturation ($S_{gc}$), and the residual oil saturation after displacement by water or gas (respectively, $S_{or,w}$ and $S_{or,g}$). The irreducible water saturation is the lowest water saturation that can be achieved by displacing water by oil or gas. $S_{wirr}$ typically varies inversely with porosity, as larger pores have smaller surface area, thereby lowering $S_{wirr}$. A representative $S_{wirr}$ for sandstone is around 20% (Zhou et al., 2000; Vrachliotis, 2012; Falahat, 2012), which is the value assumed in our models. The critical gas saturation reflects the process of bubble growth during pressure depletion, and is defined as the minimum movable gas saturation. Hence, higher critical gas saturation prevents liberated gas migration. It depends on a complex interplay of a multitude of factors, such as nucleation, diffusion, capillarity, and viscous forces, which in turn are a function of the reservoir facies. $S_{gc}$ values as low as 0.5% and as high as 38% having been reported (Falahat et al, 2014); for our modelling we use a value of 5% which is at the top of 4D seismically inferred $S_{gc}$ values, which is representative.
of both field cases. The residual oil saturation after displacement by water ($S_{or,w}$) is a function of the wettability index (the index being higher for water-wet system, which reflects high initial $S_w$), and is also a function of permeability, with high permeability resulting in more oil being displaced, and hence less residual oil remaining in place. Several studies of core and log analysis (e.g. Elkins and Poppe, 1973; Trewin and Morrison, 1992; Skauge and Ottesen, 2002) show a wide range of $S_{or,w}$, from 4-45%. Using these studies as a guide, we use an $S_{or,w}$ average value of 22% as representative of a sandstone reservoir that is water-wet. Finally, for the residual oil saturation after displacement by gas ($S_{or,g}$) we use an average value of 16% as estimated from the work of Skauge and Ottesen (2002) from 30 large scale North Sea reservoir cores for gas injection conditions. Skauge and Ottesen (2002), showed that the $S_{or,g}$ variation is relatively small, with a small reduction correlating with increasing rock permeability, but pointed to a lack of strong trends in relation to wettability and depositional environment due to potential complicated rate effects that obscure interpretation.

The range of saturation and pressure values are conditioned by fluid flow simulations of the reservoir models for the two field cases, and kept constant spatially across the 2D profile for each baseline/monitor snapshot. To assess the 4D seismic signature, we consider four saturation scenarios that represent ‘end-points’ of saturation conditions corresponding to key stages in reservoir production. In this way, the saturation scenarios represent the most ‘dramatic’ 4D effects we could aim to capture, assuming optimal timing of the seismic surveys with respect to the stages of production. Uniform conditions are of course a simplification of the pressure/saturation geometry that is heterogeneous in the field, and is meant to show 4D changes away from moving contacts (please also refer to the limitations of this approach described in the Discussion section). Specifically, we look at the following four
scenarios (Figure 2), with scenario (a) treated as the baseline case for seismic, and (b)-(d) as monitors, corresponding to a time-lapse period of roughly 1 to 2 years:

a) Pre-production condition in the oil leg, with field pressure above the bubble point, which suggests that all hydrocarbon is a liquid, in which case $S_w=S_{wirr}$, $S_o=1-S_{wirr}$ and $S_g=0$. Pressure is 260 bars for the West Africa field, and 205 bars for the North Sea field.

b) Pressure depletion condition in the oil leg, with the field pressure dropping below the bubble point. As pressure decreases below the bubble point, the gas saturation builds progressively as gas bubbles are first nucleated, and then coalesce or grow more by the diffusion of additional free gas (Falahat et al., 2014; Obidegwu, 2015). When a significant number of bubbles are liberated, the fluid system reaches the critical gas saturation, for which the gas becomes mobile. Eventually, the mobilized gas collects in local highs or structural traps to form gas caps, whereas the remaining gas stays in the oil, resulting in $S_w=S_{wirr}$, $S_o=1-S_{wirr}-S_{gc}$ and $S_g=S_{gc}$. Depending on the reservoir connectivity and injection-production scenario, this process typically occurs over a few months or less (Falahat, 2012). One interesting aspect of fluid property changes at, and near to, critical gas saturation is the change of seismic wave properties of live oil before, during and after gas exsolution. We know from laboratory experiments that free gas is known to have a substantial effect on seismic wave properties (Han and Batzle, 2000a,b), however, the impact of the gaseous phase could potentially be counteracted by the oil now becoming less ‘lively’ due to the loss of the lighter gas components. To understand whether this contribution is significant, Obidegwu (2015) modelled the fluid properties of the oil-gas mixture by taking into account the effect of the released gas in API and the gas-oil ratio (Rs) and compared them to the fluid
properties of the oil-gas mixture ignoring these oil changes, and found that fluid substitution calculations and resultant interpretations can ignore the oil phase changes to first order. Hence, in our calculations of fluid substitution, the oil properties remain constant. Pressure is 254 bars for the West Africa field, and 142 bars for the North Sea field.

c) Repressurization by water injection in the region of oil/water contact movement. In this case, the residual gas may be reduced to zero by this repressurization, in which case \( S_w = 1 - S_{or, w} \), \( S_o = S_{or, w} \) and \( S_g = 0 \). Pressure is 260 bars for the West Africa field, and 210 bars for the North Sea field.

d) Gas cap expansion through gas injection for which \( S_w = S_{wirr} \), \( S_o = S_{or, g} \) and \( S_g = S_{gmax} = 1 - S_{or, g} - S_{wirr} \). A similar case can occur through pressure depletion resulting in the creation of a secondary gas cap, although gas cap expansion through gas injection would involve higher pressures. Pressure is 254 bars for the West Africa field, and 160 bars for the North Sea field.

2.4 Upscaling

In reservoir engineering, the process of upscaling refers to substitution of a heterogeneous property region consisting of fine cells with an ‘equivalent’ homogeneous region made up of a single coarse-grid cell with an effective property value. For volumetric properties, upscaling is straightforward; for saturation the effective cell value is given by the pore volume weighted arithmetic average. On the other hand, there is no simple averaging method to upscale quantities such as permeability, which is non-additive by nature, and upscaling only provides an approximation of the true effective cell value. Upscaling is a concept that is also fairly explored in seismic modelling, either in problems involving a mere redistribution of properties in space or defining new sets of elastic properties at a coarser scale, that result in
similar seismic signatures when sampled by a bandlimited seismic wave as the fine scale properties. An interesting question is how the upscaling of reservoir fluid properties and consequent reservoir flow simulation and seismic modelling (upscaling in the fluid flow simulation domain) compares to upscaling of the fine scale reservoir flow simulation and consequent fine scale seismic modelling result (upscaling in the seismic simulation domain).

To this end, MacBeth and Stephen (2008) showed that the seismic signature of the upscaled flow properties is quite different from the upscaled seismic signature of a fine-scaled flow model. This result does not imply that upscaling in any of the two domains is ‘wrong’, as the notion of upscaling may serve different purposes in each case.

In this work, the objective is to understand the gas signature in 4D seismic in thin-bedded geology, and to assess whether modelling fluid flow and 4D seismic, using coarser grid reservoir flow simulations may obscure fine scale effects. The obvious approach would be to conduct fluid flow simulations and consequent seismic modelling of the coarse and fine scale models, which would require developing a complete 3D fine scale fluid flow simulation model, and consequently upscaling it to a coarser model with geologically realistic upscaled properties consistent with multiple phases that satisfy flux and mass conservation. Developing a 3D high-resolution model for a reservoir is a considerable task (e.g. Agada et al, 2014), while upscaling it may be just as hard and potentially unreliable (Pickup and Hern, 2002). An alternative to fine versus coarse fluid flow simulations is to consider several saturation scenarios that represent characteristic stages in reservoir production (as shown Section 2.3) for fine and upscaled models. Given these scenarios we can then model fluid distribution in space for the fine and upscaled models and compute the elastic properties through petro-elastic modelling and seismic modelling (Sections 2.3 and 2.4). This is equivalent to upscaling in the fluid flow simulation domain although it involves upscaling of
limited properties that are volumetric and not intrinsic. Specifically, we upscale pore volume
(PV), porosity ($\phi$), net-to-gross (NTG) thereby ensuring mass conservation:

$$PV_c = \sum_{i=1}^{n} PV_f$$  \hspace{1cm} (1)

$$NTG_c = \frac{\sum_{i=1}^{n} NTG_f}{n}$$  \hspace{1cm} (2)

$$\phi_c = \frac{PV_c}{V_{total}} = \frac{\sum_{i=1}^{n} \phi_f \cdot V_f}{\sum_{i=1}^{n} V_f}$$  \hspace{1cm} (3)

where $f/c$ denote the fine/coarse cells respectively and $n$ is the number of cells upscaled into one cell.

Upscaling the saturation values we obtain:

$$S_x = \frac{\sum_{i=1}^{n} PV_f S_{x_i}}{\sum_{i=1}^{n} PV_f}$$  \hspace{1cm} (4)

where $S_x$ represents any of the saturations $S_{\text{wirr}}$, $S_{\text{gc}}$, $S_{\text{or,g}}$ or $S_{\text{or,w}}$.

We perform upscaling to coarser grids of different sizes to assess whether there exists a
critical limit above which upscaling is detrimental to the 4D seismic signature: starting from
the fine-scale grid of size $dx_{\text{fine}} = 0.3m$ and $dz_{\text{fine}} = 0.25m$ to progressively upscaled grid sizes
of $dx_{\text{upscaled}} = 3m/30m$ and $dz_{\text{upscaled}} = 2m/10m$. It should be noted that the last grid size is still
comparable to the grid size used in typical reservoir flow simulations and seismic modelling.

Figure 3 shows the 2D profiles of porosity for the fine-scaled and upscaled models, with
porosity obtaining intermediate values as a result of pore volume averaging over several cells.
Figure 4 shows the 2D profiles of saturation, and this time the saturation values do not change with upscaling, only their spatial distribution does, because the amount of different fluids within the pore volume of each cell stays constant. Following petro-elastic modelling for different saturation scenarios, we obtain the fine and coarse scale impedances (Figure 5) which result in smoother reflection coefficient series and obviously decreased number of interfaces as a result of upscaling.

2.5 Seismic Modelling

There are numerous synthetic seismic modelling techniques, and in most cases there is a trade-off between the level of accuracy in modelling the full seismic wave phenomena, and computation time. Seismic convolution is one of the most common techniques used in synthetic seismic generation from fluid flow simulations as it can be directly compared to post-stack data involving very simple computations. Amini (2014) compared 4D sections from synthetic seismic using 1D convolution of the primary reflection coefficient series after application of a migration operator versus finite-difference modelling, and computed 4D RMS curves consistent to approximately 85%. Although convolution can handle angle dependence through Zoeppritz equations, and some degree of processing choices through selection of an ‘average’ wavelet extracted from the observed seismic data, it only captures primary reflections and does not include interference effects from multiples. In the case of stacked thin layers, as shown in O’Doherty and Anstey (1971), short-period multiples, which are multiples arriving within the duration of the propagating wavelet, can significantly contribute in the waveshape and amplitude of primary reflections, both through constructive and destructive interference, depending on whether the stratigraphy is cyclic or transitional in nature, respectively. Hence, we expect that in the case of thin-bedded geology, if simulator-to-seismic modelling is performed based on convolution with the primary reflection
coefficient series only, and does not include multiples, it may fail to capture these interference effects of short-period multiples in a static sense, and in turn time-lapse seismic interpretation may also be inaccurate.

As an alternative to simple convolution, we consider the reflectivity algorithm, which includes contributions from all possible rays within the reflecting zone, including converted waves and multiples. Generally, the reflectivity method can generate realistic seismogram for layered media (Cheng and Margrave, 2011, accessed through: https://www.crewes.org/ForOurSponsors/ResearchReports/2011/CRR201116.pdf). In this work, we use the Kennett reflectivity algorithm (Kennett, 1983), which computes the reflection and transmission coefficients for plane waves incident on a stack of homogeneous layers through a recursive algorithm using a slowness-frequency domain synthesis. This algorithm allows for multiples/converted waves to be switched on and off, and also for shot-gathers with/without move-out corrections to be generated. As it involves plane wave theory, results are limited to angles smaller than the critical angle. Extensions of this algorithm, which are not explored in this work, involve azimuthally anisotropic layered models and also inclusion of near-field terms, which is suitable for issues near the critical angle (Kennett, 1993, accessed through: http://epress.anu.edu.au/seismic_citation.html).

3 TIME-LAPSE SEISMIC SIGNATURE

First, we consider the effect of saturation and pressure conditions (scenario (a) through (d) as described in 2.3) in the seismic response of the fine-scale model with elastic properties modelled after the North Sea and West Africa example fields. Figure 6 shows the seismic synthetic data computed with a 65 Hz Ricker source wavelet without multiples, hence considering only primary reflections and transmission losses. As the North Sea model is a
high-to-low impedance model, namely the shale is harder than the reservoir sand, the gas signature results in the largest absolute amplitudes (brightening) relative to the baseline (pre-production, oil-saturated state). On the other hand, in the case of the West Africa field model, which is a low-to-high model, one would expect that the presence of gas would result in dimming, due to a reduction in the reflection coefficient between shale/sand. However, synthetic seismic data show an increase of absolute amplitudes in gas-saturated relative to the baseline, as well as a polarity reversal. This effect can be explained through computation of the impedances and reflection coefficients across the different fields shown in Figure 7, with the reflection coefficient being positive for the pre-production (a) and water-saturated (c) scenario, and negative for the critical gas (b) and maximum gas saturation (d). We expect positive and negative reflection coefficients for the sand/shale and shale/sand interfaces, respectively, however, due to fine layer thickness we cannot resolve each interface, but instead observe tuning with some level of constructive interference. Next we include multiples in the synthetic seismic model, and observe a pronounced increase in absolute amplitudes, for all cases considered (ie different field geology, saturation conditions) (Figure 8). In the absence of a free-surface/surface, water/sea-floor, overburden/reservoir boundary which has not been considered in this model, the nature of these multiples are intra-bed multiples, which should interfere constructively due to the cyclic nature of the outcrop analogue, in accordance to O’Doherty and Anstey (1971) theory. Indeed, as shown in Figure 8, inclusion of multiples in the synthetics causes an increase in seismic amplitude, which implies that the short-period multiples are of the same polarity as primary reflections. Moreover, summation of short-period multiples can lead to potentially larger seismic amplitudes than those observed from primary reflections alone, thereby contributing significantly to 3D seismic amplitude (Figure 8), and potentially time-lapse seismic amplitude.
To assess the impact of gas in thin bedded geology we compute the 4D difference between the seismic traces, using the monitor and baseline seismic sections for maximum gas saturation and oil saturated conditions described as scenario (d) and (a), respectively. Figure 9 shows the 4D differences of the fine scaled and upscaled models both without multiples in the modelling and including multiples. Two observations stem out of the time-lapse seismic sections. Firstly, the time-lapse signature of gas in thin-bedded geology is stronger due to the presence of multiples, which is evident from the no multiples/with multiples 4D seismic sections of the fine-scaled model (model (i)). Hence, a simple seismic convolutional model with the reflectivity series will fail to capture the full 4D seismic gas signature. Secondly, as we upscale, as shown in Figure 9 for models (ii) and (iii), the 4D seismic gas signature effects diminish, and whether seismic modelling includes multiples or not, does not improve the accuracy of 4D response. This is expected as upscaled models are less energetic due to reduced reflectivity coefficients, and decreased number of layers, which implies that fewer multiple reflections contribute to the primary. These trends are consistent across AVO (Figure 10), shown for angle stacks 0°-10°, 10°-20°, 20°-25°. To quantify the 4D signature, we compute the Normalised-Difference-Root-Mean-Square (NdRMS) defined as the difference of the root-mean-square (RMS) of the monitor and base volumes through the equation (Stammeijer and Hatchell, 2014):

$$NdRMS = \frac{1}{2} \left( \frac{RMS(M) - RMS(B)}{RMS(B) + RMS(M)} \right)$$

where M and B stand for monitor and baseline trace, respectively. As explained by Stammeijer and Hatchell (2014), this attribute preserves the polarity of change and is suitable to compare changes occurring at the reservoir level to changes at other levels. In our case, we use Normalised-Difference-Root-Mean-Square to capture the differences between monitor...
and baseline traces for different levels of upscaling and additional effects from multiples (Figure 11). The fine scale model shows an increase in Normalised-Difference-Root-Mean-Square of ~20% when multiples are included across different stacks, with very small differences observed in the upscaled models. In fact, for the upscaled model (iii), the reduced number of interfaces due to the coarser grid and the reduced reflection coefficients due to smoothing result in minimum reflection energy, and consequently multiple reflection energy, causing the ‘no multiples’ and ‘with multiples’ seismic synthetics to look almost identical. To explore the effect of seismic data frequency content, we remodel the synthetic seismic data using a Ricker wavelet with centre frequency 22 Hz, which is representative of the North Sea seismic experiment. Figure 12 shows the 4D difference between the monitor modelled for maximum gas saturation and the baseline for oil saturated conditions across the same angle stacks. It is perhaps surprising that even with the low frequency source, we are able to detect a strong gas signature, that is further strengthened by multiples contributing to ~15% in the Normalised-Difference-Root-Mean-Square (Figure 13).

In addition to 4D amplitudes, we also compute the time-shift (Δt) signature due to gas saturation. Post-stack time shifts, measured as two-way time differences between time-lapse seismic vintages are routinely used to monitor strain changes related to geomechanically active reservoirs and also saturation changes. Measured changes values range from 0.2ms to over 20ms depending on field production and recovery, reservoir thickness, depth and elapsed time period (MacBeth and Mangriotis, 2017). Numerous (over ten) methods are available to compute post-stack time-shifts (the reader is referred to Ji (2017) for a review and comparison of different time-shift measurement methods). We use Rickett et al. (2006) 1D fast cross-correlation algorithm, which is a robust and straight-forward time-shift technique that can recover time-shifts without reduction in resolution due to over-smoothing.
Selection of optimum window length and maximum correlation lag is typically a trial-and-error process; there exists a trade off between smoothing (large window) and having a noisy time-shift result (small window), whereas the maximum lag should be in the range of the expected time-shift (unless a cascaded approach of bulk plus fine time-shift computation is adopted). Time-shifts are computed using a window length 0.06s and lag 0.012s for the 65Hz source synthetics, and a window length 0.1 s and lag 0.042s for 22Hz (Figure 14). This selection ensures that the source wavelet is contained entirely within the window and that the maximum lag is larger than the maximum expected time-shift. The effect of fine-scale geology, which dictates the layer thickness and velocity, combined with the source wavelength gives rise to very distinct and non-intuitive time-shift patterns. The time-shift between two-way time differences measured from slowness averages between the baseline and monitor is in the order of 1.5ms. In the case of the 65Hz source synthetics, estimated time-shifts from the cross-correlation algorithm are in the same order of magnitude with the ray theory traveltime differences with multiples leading to an increase of time-shift in the order of 30%. Expectedly, there are anomalous time-shifts measured outside of primary reflections’ arrival times in the case of measured time-shifts in synthetics with multiples, as the signal is comprised entirely of higher order multiples at those arrival times. We believe that these higher order multiples interfere with each other in distinct patterns for each seismic vintage, and that the time-shift measurement responds to changes in the waveforms between baseline and monitor traces thereby resulting in anomalous time-shifts. This is also the case for the 22Hz source synthetics, where changes in waveform dominate time-shifts to the extent that they completely override any time-shift caused by two-way time differences. This is evident not only in the region of higher-order multiples, but interestingly also in the region of primary reflections in both synthetics with and without multiples.
4 DISCUSSION

This study addressed the implications of having fine scale geology as it affects 4D seismic analysis and specifically gas signature identification. We showed a case study modelled after an outcrop analogue for thin sandy turbidite geology and reproduced field reservoir conditions during several stages of production. Our aim was to challenge 4D seismic interpretation that is based on simulator-to-seismic modelling of upscaled fluid flow simulation models, which may not be appropriate in case of thin-bedded geology. Our analysis highlighted two separate scale effects linked to both fluid flow modelling and seismic modelling. The first scale effect involves the distribution of fluid volume in space, and its translation to elastic wave properties. Effectively, the same volume of fluid should be present in fine and coarse scale models, if upscaled correctly, but it occupies high porosity ‘veins’ in fine scale models versus intermediate porosity ‘blocks’ in the coarse scale model. This in turn translates to smoother impedance contrasts (smaller reflection coefficients) and smaller number of contrasts of larger thickness. As discussed in Stovas and Ursin (2007), the distinction between an effective medium and time-average medium, and the width of their transition zone, not only depends on the value of wavelength to layer thickness ($\lambda/d$), but also on the reflection coefficient between layers, with the sequence between effective medium/transition zone/time-average medium periodically repeated with higher frequencies. Therefore, the impact of upscaling in 4D seismic cannot be generalized and must be considered on a case by case basis, and will depend on geology, static and dynamic rock and fluid properties, as well as the seismic bandwidth, with different frequency bands potentially observing a different medium scheme. Moreover, effective medium/time-average medium theories are based on binary medium assumption, which is a mathematical simplification. In a synthetic study, Barrett-Crosdil (2015) looked at the gas signature for different reflection
coefficient patterns, for varying magnitude, sequence patterns, and thickness, concluding that both false positive and negative gas signatures are possible due to tuning. In fact, the classic paper of Widess (1973), which describes tuning for a thin bed surrounded by two layers of the same sediment, has been so influential in geophysicists’ thinking, that we often forget that tuning behaviour is quite unique to the reflectivity pattern.

The second scale effect which this study has highlighted, and which has not been addressed explicitly in studies looking at the seismic response due to subseismic resolution geology (such as Sengupta, 2000; Castro and Caers, 2005; Falivene et al, 2010) concerns the effect of short-period multiples. Conventional seismic processing aims to create multiples’ free seismic data by identifying and attenuating multiples. Several surface-related multiple elimination (SRME) and internal multiple removal (IME) schemes have been successfully applied to marine and land data, with IME historically receiving less attention. (for a recent review of SRME and IME methods, the reader is referred to Filho et al., 2017). Intrinsic to the multiple removal schemes is the definition of a depth level at which a multiples’ estimate is desired, in other words, knowing where these multiples originate from (Verschuur, personal communication). Therefore, at best, we can remove all multiples from an interface that is specified, but could we practically define all interfaces in the subsurface? In the case of thin-bedded geology, we expect some degree of internal multiples, to remain, which will thereby constitute the generalized primary reflection, as defined by Resnick et al. (1986) as ‘the classical primary from a reflector and all multiples whose propagation paths are confined to the region above (or below) the reflector’. Our case study showed an increase in Normalised-Difference-Root-Mean-Square when multiples are included, for both the high frequency model with wavelength to layer thickness ($\lambda/d$) equal to 40 as well as the low frequency model with $\lambda/d$ equal to 100. However, one could argue that the Normalised-
Difference-Root-Mean-Square difference due to multiples hereby shown is not significant, in the sense that an interpretation based on modelling primaries only would still give an 80% solution.

The most dramatic effect due to thin bedded geology is likely to impact the time-shift attribute. Our results showed, that interference of primaries and multiples resulting in a change of waveform may be the dominant effect between baseline and monitor, such that the time-shift algorithm no longer responds to the time-lapse velocity change (ΔV) and becomes ‘spurious’. This implies that ΔV information may not be recoverable if thin beds are present through time-shift measurement at the location of the time-lapse velocity change, but possibly from analysis of deeper target areas taking advantage of the cumulative nature of time-shift (provided that the deeper areas do not contain thin beds and do not themselves have a separate ΔV mechanism). Such an example could be inferring reservoir ΔV from the underburden response. To our knowledge this is the first published study showing as a case study the effect of internal multiples on time-shift measurement. Spurious time-shifts were first studied by MacBeth et al. (2016) and were found to give up to 200% error within the reservoir and underburden. They found that spurious time-shifts were a consequence of time-lapse tuning, which was worst in the case of 4D polarity reversal at an interface. It should be noted however, that although MacBeth et al. (2016) did include thin layers in their analysis, the time-lapse velocity changes they studied were lower frequency than the layer thickness, which may have produced less spurious time-shifts than the model presented here. In addition, their seismic modelling included primaries only. The effect of multiples in time-shift measurement is a topic that remains largely unexplored. Hatchell et al. (2008) studied the effect of multiples in the water column and showed that the time-shift bias from multiples is linearly dependent on the velocity difference of the water velocity between baseline and
monitor and proposed a time-shift correction for the multiples in the water column. Fehmers (2010) presented a case study of the Tyra field where he modelled the effect of multiples through a convolutional model of the reflectivity with itself and the source function, which accounts for surface related multiples, of the first-order only). Assuming processing only removes 4/5 of multiples, he showed that the multiples remaining can cause time-shifts twice the size from time-shifts originating from primaries, and suggested that unexplained time-shift measurements in Tyra could be partially attributed to multiples. Sanchez (2016) studied the effect of multiples on time-shift during gas exsolution, using a similar model of multiples as Fehmers (that produced surface related, first order multiples only) and found that those multiples gave rise to spurious time-shifts that were not present in the primary only synthetic models. Spurious time-shifts due to multiples were also found by Sam-Okyere (2016) who modelled water-flooding, showing that the inconsistency in time-shift measurement between primaries only and primaries with multiples included was larger for larger seismic source frequency, although spurious time-shifts reduced with increasing frequency for the primaries model only, in agreement with MacBeth et al. (2016).

Understanding that thin beds, especially gas-saturated, may result in brighter 4D amplitude differences than our modelling suggests, and anomalous time-shift signatures in field data, opens up two possibilities for accurate interpretation. The first obvious route is continued progress in the analysis of seismically thin beds, which aims at accurately and quantitatively predicting thin-bed distribution and their properties. Such analysis relies on several combined advanced thin-bed attributes, and is notoriously subtle and difficult (for an up-to-date summary, the interested reader is referred to Zeng and Marfurt, 2015). We can expect, however, that by increasing our understanding of thin-bed behaviour, we may succeed at identifying and isolating hydrocarbon detection from the disturbing effects of interference.
Following this philosophy, Wang et al. (2014) show a synthetic and field data example of hydrocarbon detection through spectrum attenuation of interference effects. As noted by Zeng and Marfurt (2015), thin bed analysis is characterised by elevated non-uniqueness and uncertainties compared to thick-reservoir characterization. As an alternative to thin bed analysis, a suggested approach is to capture interference effects within a simulator-to-seismic framework at a (coarse) scale comparable to the reservoir simulation grid with the inclusion of a cell-dependent thin-bed stratigraphic filter. We propose that the stratigraphic filter be externally conditioned to representative outcrop analogues, and reflect fluid saturation and possibly pressure content, essentially a time-lapse stratigraphic filter. This research strategy merits further study.

Prior to concluding, we acknowledge two limitations that are inherent in this work. The first limitation is the absence of fluid flow simulation, as our analysis was based on saturation/pressure scenarios that were uniformly applied spatially onto the outcrop geological model. This does not preserve the geometrical dynamic architecture of the field (i.e. location of producing/injecting wells, OWC etc). As a result, our models do not show moving contacts, which are potentially important features in the 4D seismic response. In addition, in upscaling we forced fluid volumes to be conserved between fine scale and coarse scale, which may not have been the case should we have upscaled a fluid flow simulation model. As previous authors have noted (for example, Castro and Caers, 2005) coarse scale fluid flow models may result in no change in saturation in areas where saturation changes should be present, and consequently 4D seismic signal. From the perspective of seismic modelling, further limitations apply. Firstly, seismic modelling was based on the Kennett (Kennett,1983) algorithm which is a 1D algorithm (assuming no lateral heterogeneity). This is not representative neither of seismic wave propagation in a 3D medium, nor of seismic data.
processing (such as multiple removal, migration etc). Secondly, our AVO results were also based on 1D synthetic generation and ‘perfect’ NMO correction as a result of horizontal slowness correction, which would be impossible to achieve in real data. Therefore, we expect the AVO patterns to be different especially in view of contribution from internal multiples, which are horizontal-slowness corrected in the synthetics, but not in real data. Finally, our modelling was based on an outcrop analogue and considered interference effects from fine-scale geology at a very localized scale (50m depth). We expect that additional interference phenomena may occur and overlap with the response at the depth of interest when the full-scale 4D study is considered, that includes for example free-surface, sea-floor, and overburden effects.

5 CONCLUSIONS

Through a case study using an outcrop analogue of a thin-bed turbidite, it is shown that the time-lapse signature of gas is strongly influenced by the constructive interference of primary and multiple reflections due to the cyclicity of stratigraphy. This suggests that gas response in field data is potentially larger than modelling predictions using simple convolutional models. We use log-calibrated rock properties (static component), and fluid, saturation and pressure conditions (dynamic component) to compute realistic elastic properties for the subsurface using two fields examples: one from the North Sea and the other from West Africa. We compare four saturation/pressure scenarios corresponding to ‘key’ reservoir conditions including oil-saturated, water-saturated and maximum gas saturation to explore a range of time-lapse seismic signatures. Using the Kennett (Kennett,1983) algorithm, we compute synthetic seismic data with and without multiples and conclude that short-period multiples, which are often not included in a synthetic-to-seismic modelling routine, are potentially significant both in terms of amplitude contribution as well as time-shift. In the context of
upsampling fluid flow models, which is often necessary in reservoir engineering, we show that in the presence of thin-bedded geology, upscaling does not adequately represent time-lapse seismic signatures due to relative changes in layer thickness as well as reflection coefficient reductions, that alter interference patterns. With reflection interference being uniquely linked to stratigraphy, our recommendation is that any forward/inverse modelling from the fluid flow simulation to the seismic domain involved in quantitative 4D must take into account thin layers when these are present in the geological setting.

6 ACKNOWLEDGEMENTS

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8 APPENDIX

As mentioned in 2.3, there are numerous petro-elastic model formulations in the literature, and for this work we have adopted one of the paradigms discussed by Briceño et al. (2016) which involves mixing before fluid substitution and is appropriate for a clastic reservoir. The details of this model ensue.

Mixing Before Fluid Substitution An assumption for the rock matrix is that it is comprised of a mix of cleanest sand and purest shale, with matrix moduli ($M_{\text{matrix}}$), where $M$ represents either bulk and shear, estimated as an arithmetic mean of a Voigt ($M_V$) upper and Reuss lower ($M_R$) bound (Mavko and Mukerji, 2009):

$$M_V = \sum_{i=1}^{N} f_i M_i$$  \hspace{1cm} (A.1)

$$\frac{1}{M_R} = \sum_{i=1}^{N} \frac{f_i}{M_i}$$  \hspace{1cm} (A.2)

where $f_i$ is the volume fraction for each phase $i$ (in this case sand/shale).

For the estimation of density, the matrix density ($\rho_{\text{matrix}}$) is computed as a Voigt volume average of the end members.

Porosity Dependence of Dry Frame Moduli The dry frame moduli ($K_{\text{dry}}$, $\mu_{\text{dry}}$) dependence on porosity $\phi$ is estimated through the consolidation factor $\alpha$ (Lee, 2005), obtained from a multilinear regression (Amini, 2014; Briceño, 2017):
\[ K_{\text{dry}} = K_{\text{matrix}} \frac{1 - \phi}{1 + \alpha \phi} \]  
\text{(A.3)}

\[ \mu_{\text{dry}} = \mu_{\text{matrix}} \frac{1 - \phi}{1 + \alpha \phi} \]  
\text{(A.4)}

\[ \alpha = aV_{\text{sand}} + bV_{\text{shale}} + c\phi \]  
\text{(A.5)}

where \( K_m \) and \( \mu_m \) are the matrix bulk and shear moduli, respectively.

**Pressure Dependence of Dry Frame Moduli**  
The dry bulk and shear moduli also depend on changes in effective stress, which may affect the mineral fabric. The effective stress depends largely on induced pore pressure variations in the reservoir. In the absence of geomechanical laboratory data to test rock frame response to pressure changes, we model the stress sensitivity based on MacBeth (2004), with sand and shale regarded as equally stress sensitive (Hajasser, 2012). Changes of the dry moduli pressure are given by:

\[ K_{\text{dry}}(P) = \frac{K_\infty}{1 + E_\kappa \frac{P_{\text{eff}}}{P_\kappa}} \]  
\text{(A.6)}

\[ \mu_{\text{dry}}(P) = \frac{\mu_\infty}{1 + E_\mu \frac{P_{\text{eff}}}{P_\mu}} \]  
\text{(A.7)}

where \( K_\infty \) and \( \mu_\infty \) are the background high-pressure asymptotes, \( P_k \), \( P_\mu \) are the characteristic pressure constants that determine the rollover point beyond which the rock frame attains its state of relative insensitivity, \( E_\kappa, E_\mu \) are constants calibrated from isotropic loading and \( P_{\text{eff}} \) is the effective stress of the reservoir at different times during the production, estimated as:

\[ P_{\text{eff}} = \sigma_{ob} - nP_{\text{pore}} \]  
\text{(A.8)}
Fluid Properties After computing the dry rock properties, we compute the density and bulk modulus of each single phase fluid (water, gas, oil) through the equations of Batzle and Wang (1992), based on the pressure, salinity, and temperature and the known black oil properties (API, gas gravity, oil-formation volume factor, and solution gas-oil ratio) for the reservoir cases considered. To take into account the different fluid phases present in the pore space at different stages in production, we use Gassmann’s equations (Gassmann, 1951) which are strictly valid for isotropic, homogeneous media. One of the concepts implicit in Gassmann’s formulation is that the mixed fluid phases in the pore space are represented by a single 'effective fluid'. The effective fluid model is valid when the fluid phases are mixed at a fine scale, which is smaller than a critical relaxation scale (Mavko et al., 1998). The diffusion length \( L_C \) can be estimated approximately as

\[
L_c = \frac{D}{f}
\]

where \( D \) is the hydraulic diffusivity and \( f \) the seismic frequency. When the characteristic scale of the saturation heterogeneity is small compared to the diffusion length \( L_C \) then wave-induced differences in pore pressure between different fluid phases have sufficient time to flow and equilibrate during the seismic period. This is called the 'effective medium relaxed' state (Sengupta, 2000). Given our permeability estimates for the modelled reservoirs and the cell size of the modelled outcrop being below the diffusion length, the effective fluid assumption valid is valid for our case. The corresponding effective fluid bulk modulus is calculated through harmonic averaging (Domenico, 1974):

\[
K^\text{eff} = \frac{S_w}{K_w} + \frac{S_o}{K_o} + \frac{S_g}{K_g}
\]

The fluid density is a volumetric average, namely:
The saturated density is in turn calculated as the volume average of the solid and liquid phase:

\[ \rho_{\text{sat}} = \rho_{\text{fluid}} \phi + (1 - \phi) \rho_{\text{matrix}} \]  \hspace{1cm} (A.12)

Finally, from the estimated dry rock properties and fluid properties, we compute the saturated moduli using Gassmann’s equations:

\[ K_{\text{sat}} = K_{\text{dry}} + \frac{\left(1 - \frac{K_{\text{dry}}}{K_{\text{matrix}}} \right)^2}{\phi + \frac{1 - \phi}{K_{\text{fluid}}/K_{\text{matrix}} - \frac{K_{\text{dry}}}{K_{\text{matrix}}}}} \]  \hspace{1cm} (A.13)

\[ \mu_{\text{sat}} = \mu_{\text{dry}} \]  \hspace{1cm} (A.14)

Finally, we compute the velocities of the fluid saturated rocks (assumed to be isotropic) through:

\[ V_p = \sqrt{\frac{K_{\text{sat}} + \frac{4}{3} \mu_{\text{sat}}}{\rho_{\text{sat}}}} \]  \hspace{1cm} (A.15)

\[ V_s = \sqrt{\frac{\mu_{\text{sat}}}{\rho_{\text{sat}}}} \]  \hspace{1cm} (A.16)
### Table 1: Rock properties for the North Sea and West Africa fields for sand and shale.

<table>
<thead>
<tr>
<th></th>
<th>SAND North Sea</th>
<th>SHALE North Sea</th>
<th>SAND West Africa</th>
<th>SHALE West Africa</th>
</tr>
</thead>
<tbody>
<tr>
<td>φ</td>
<td>0.3</td>
<td>0.16</td>
<td>0.3</td>
<td>0.12</td>
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<tr>
<td>NTG</td>
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<td>0.1</td>
<td>0.93</td>
<td>0.07</td>
</tr>
<tr>
<td>K (GPa)</td>
<td>34</td>
<td>15</td>
<td>18.52</td>
<td>9.38</td>
</tr>
<tr>
<td>G (GPa)</td>
<td>15</td>
<td>10</td>
<td>6.46</td>
<td>2.26</td>
</tr>
<tr>
<td>ρ(kg/m³)</td>
<td>2615</td>
<td>2607</td>
<td>2619</td>
<td>2330</td>
</tr>
</tbody>
</table>

### Table 2: Field properties for the North Sea and West Africa fields.

<table>
<thead>
<tr>
<th></th>
<th>Pressure (pre-production) (bars)</th>
<th>Temperature (°C)</th>
<th>Salinity (ppm)</th>
<th>Gas gravity</th>
<th>API</th>
<th>Solution gas-oil ratio (scf/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Sea</td>
<td>205</td>
<td>57.8</td>
<td>18000</td>
<td>0.58639</td>
<td>25</td>
<td>81.1</td>
</tr>
<tr>
<td>West Africa</td>
<td>260</td>
<td>65</td>
<td>117000</td>
<td>0.58639</td>
<td>32</td>
<td>131.4</td>
</tr>
</tbody>
</table>
Figure 1: (a) Photopanel of Ainsa II (Clark, J., 2008), (b) fine scale binary numerical model (Lopez, 2006) showing shale and sand layers in blue and red, respectively. The outcrop dimensions are 50m (depth) x 750m (width).

Figure 2: Schematic diagram showing four saturation scenarios considered along with the corresponding water, oil and gas saturations in each case: a) pre-production in oil leg, b) pressure depletion in oil leg, c) oil/water contact movement due to water injection, d) creation of secondary gas cap due to gas cap expansion and/or gas injection.
Figure 3: Porosity of outcrop models for fine-scale (top) and upscaled models (middle and bottom). Corresponding grid sizes are 0.3m x 0.25m, 3m x 2m, and 30m x 10m, respectively.

Figure 4: Saturation profiles for scenarios (a) through (d) described in Figure 2, showing oil, water and gas saturations for the fine scale (i) and upscaled models (ii) and (iii). Corresponding grid sizes are 0.3m x 0.25m, 3m x 2m, and 30m x 10m, respectively.
Figure 5: Impedance profiles for saturation scenarios (a) through (d) for the fine scale (i) and upscaled models (ii) and (iii). As expected, the process of upscaling results in smoothed impedances, and as a result lower reflection coefficients across interfaces. Corresponding grid sizes are 0.3m x 0.25m, 3m x 2m, and 30m x 10m, respectively.
Figure 6: Seismic response for different field cases: North Sea (left) and West Africa (right) showing the effect of saturation and pressure conditions (scenario (a) through (d)). Seismic synthetics are computed without multiples with a Ricker wavelet of 65 Hz centre frequency. Amplitudes across trace displays are scaled to a global maximum.
Figure 7: Left: Impedance for scenario (a) through (d) computed for the N.Sea example (red) and West Africa example (blue) fields. Right: Reflection coefficient computed for vertical incidence between the shale/sand interface for North Sea example (red) and West Africa example (blue) fields.
Figure 8: Effect of multiples: North Sea field example for water-saturated case showing seismic synthetics modelled with no multiples (left), with multiples (middle), and multiples’ contribution only (right) equal to their difference. Amplitudes of trace displays are scaled to the maximum of each scenario/field example, to show the relative contribution of multiples to the synthetic seismic data.
Figure 9: 4D seismic differences using oil-saturated baseline and maximum gas-saturation for monitor. Seismic differences are shown for (i) fine scale, and (ii) –(iii) upscaled models. Top row shows schematic porosity for model (i)-(iii) corresponding to grid sizes 0.3m x 0.25m, 3m x 2m, and 30m x 10m, respectively. Time-lapse synthetics are modelled without multiples (middle row) and with multiples (bottom row). Amplitudes of trace displays are scaled to the global maximum.
Figure 10: 4D seismic differences using oil-saturated baseline and maximum gas-saturation for monitor. Seismic differences are shown for (i) fine scale, and (ii) –(iii) upscaled models. Time-lapse synthetics are modelled without multiples (top rows) and with multiples (bottom rows). Near (left column), mid (middle column) and far (right column) stacks correspond to angle ranges of 0°-10°, 10°-20°, 20°-25°, respectively. Amplitudes of trace displays are scaled to the global maximum.

Figure 11: Average Normalised-Difference-Root-Mean-Square values as a function of angle of incidence for (i) fine scale model (left), and (ii)-(iii) upscaled models (middle, and right) for seismic
synthetics with primaries only (blue line) and including multiples (blue line). For the upscaled model (iii) synthetics with and without multiples are almost identical, and as a result the NdRMS trends overlap.

Figure 12: 4D seismic differences using oil-saturated baseline and maximum gas-saturation for monitor. Seismic differences are shown for the fine scale model using a 22 Hz Ricker as the seismic source. Near (left column), mid (middle column) and far (right column) stacks correspond to angle ranges of 0°-10°, 10°-20°, 20°-25°, respectively. Amplitudes of trace displays are scaled to the global maximum.

Figure 13: Average Normalised-Difference-Root-Mean-Square values as a function of angle of incidence for fine scale model using a 65Hz (left) and 22Hz Ricker (right) as the seismic source for seismic synthetics with primaries only (blue line) and including multiples (blue line).
Figure 14: Time-shift estimates for synthetics without multiples (middle column) and synthetics with multiples (right column) for a seismic source of 65 Hz (top row) and 22Hz (bottom row). For reference, 4D seismic differences are shown on the left column.