THE INTEGRATION OF LABORATORY DATA WITH FLOW SIMULATION FOR APPLICATION TO SEISMIC RESERVOIR MONITORING

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I dedicate this thesis to my parents.
Abstract

This thesis reports an exhaustive time-lapse seismic feasibility study conducted on a reservoir analogue by quantitatively integrating techniques from the rock physics and the flow simulation disciplines.

Extensive rock physical laboratory experiments were performed at different effective stress levels on dry and fluid-saturated sandstones of Cretaceous age, collected from a mine and used as analogue for shallow marine sandstone reservoirs. The samples were loosely consolidated, well-cemented, and unconsolidated, which provided a unique data set of cores differing only in their grain-to-grain contact compliance and covering a wide porosity range. A methodology based on an effective medium approach has been developed to quantify the degrees of consolidation and cementation on the stiffness of the rock frame by introducing the concept of stiffness parameter. Results have revealed that cementation increases the stiffness of the rock frame much more than consolidation, especially at low effective stress levels. The analysis of the evolution of compressional wave velocity with saturation on partially fluid saturated sandstones has highlighted that the fluid distribution within the samples is respectively uniform or patchy in the case of fluid injection technique by respectively imbibition or drainage.

These rock physics relationships were then used to compute the elastic property changes of a 2-D shoreface reservoir model, built for flow simulation, from a geological outcrop of the Book Cliffs of Eastern Utah. The analysis of the flow simulation results of the sensitivity study has revealed that the parameters with the largest effect on the time-lapse response are the elasticity of the rock frame and its pressure sensitivity. Moreover, it has illustrated that the recovery process corresponding to the most efficient
hydrocarbon recovery does not necessarily produce the largest time-lapse response. The analysis has finally addressed the dependence of the modelled time-lapse response on the vertical size of the grid block, and has illustrated that significant uncertainties can be created if too coarse grid blocks are used at the sub-seismic scale. This has led to the finding that gas injection process needs fine scale modelling whereas water injection and pressure depletion scenarios can be modelled at a coarser scale.
Introduction

Reservoir geophysics and seismic reservoir monitoring in particular have considerably expanded in the petroleum industry since the mid-1990’s. Such studies are based on the integration of various disciplines including rock mechanics, rock physics, petrophysics, geology, petroleum engineering, and geophysics. This requires communication between people from different technical backgrounds to understand holistically the static and dynamic behaviour of the reservoir and their integration to enhance hydrocarbon recovery.

This present work was initiated in this multidisciplinary perspective by a seismic contractor company, C.G.G. (Compagnie Générale de Géophysique) and has been undertaken in a petroleum engineering environment. It began at a time when the industry was still in a transition to a definitive acknowledgement of the real potential of seismic reservoir monitoring. Time-lapse seismic value as a key tool for reservoir management is now widely recognised within the petroleum industry. This study reports part of an ongoing study into the integration of rock physics, reservoir simulation and geophysics within the Department of Petroleum Engineering at Heriot-Watt University.

The aim of this dissertation was to undertake an exhaustive synthetic feasibility study for seismic reservoir monitoring by integrating aspects of these various disciplines for predicting time-lapse response and focusing on specific issues to improve its quantitative analysis. The approach followed was first to carry out petrophysical and rock physics measurements on clastic core samples collected from a same location but with different petrophysical properties. Three sets of samples were selected: loosely
consolidated sandstones, well-cemented sandstones and disaggregated sands. This allowed assessing the impact of both degrees of consolidation and cementation on the stiffness of the rock frame of core samples differing only in their grain-to-grain contact compliance and porosity. Their pressure dependence and their sensitivity to fluid effects were also investigated.

In the context of seismic reservoir monitoring, laboratory experiments on core samples are the first step within the workflow of time-lapse response prediction. The next step is to relate the rock physics relationships to the reservoir geological context and to the hydrocarbon recovery process. This was performed by integrating the elastic properties of the core samples into 2-D models for flow simulation representing a geological outcrop from a similar depositional environment to this of the core samples. Pressure and fluid saturation as a function of production time, extracted from the flow simulator results, were combined with acoustic properties of fluids and rock frame elasticity parameters to derive the elastic time-lapse response using Gassmann’s relations. Several hydrocarbon recovery scenarios were carried out, involving different fluids for sensitivity analysis and results comparison. Two types of models were built using different sizes of grid blocks (fine and coarse) after appropriate upscaling of the petrophysical properties to compensate for numerical dispersion. This allowed assessment of the influence of the cell size on the overall time-lapse response.

This thesis is subdivided into 5 different chapters. Chapter 1 gives a general overview of the seismic reservoir monitoring topic, states the limits of the state of the art and presents the specific aspects investigated within this multidisciplinary study. Chapter 2 describes the laboratory experiments performed on the core samples and presents the corresponding results. Chapter 3 focuses on the analysis and on the interpretation of the results of these experiments. Chapter 4 introduces the geological environment of the
reservoir model and describes the building of the flow simulation models. Chapter 5 presents the results of the time-lapse response modelling from the integration of rock physics and flow simulation disciplines and focuses on their analysis. The main conclusions drawn from the different sections of this thesis are then reported in Chapter 6 with indications for further work.
Chapter 1: Overview of Seismic Reservoir Monitoring

The aim of this chapter is to present a general overview of the seismic reservoir monitoring topic. The detailed background referring to the technical issues raised in this study is reported separately in each of the corresponding following chapters.

Since the mid-1990's, the importance of seismic reservoir monitoring within the petroleum industry has expanded considerably (Figure 1.1). The number of publications related to this topic has also increased dramatically (Figure 1.2).

![Figure 1.1: Number of seismic reservoir monitoring projects conducted worldwide from 1985 to 1999 (compiled by JNOC).](image)
The reasons for such an increase are both technical and economical. Firstly, it is indeed technically extremely challenging to seismically image the dynamic internal reservoir changes due to hydrocarbon exploitation. Secondly, the potential of seismic reservoir monitoring to increase producible hydrocarbon reserves is significant and may reach up to 70% recovery in some particular fields (Anderson et al., 1997). This huge potential, already revealed in the late eighties (Nur, 1989), is now a consensus within the whole petroleum industry.

This chapter gives an overview of the seismic reservoir monitoring topic. It first respectively focuses on the following aspects:

i. the definition of seismic reservoir monitoring and the description of the information that this technique can provide;

ii. the key role that seismic reservoir monitoring plays for the contribution of integration of disciplines for improving reservoir management;

iii. the support of theoretical and experimental laboratory studies for the use of seismic reservoir monitoring on field scale trials;

Figure 1.2: Number of publications related to seismic reservoir monitoring from 1996 to 2000 (after Lanfranchi, 2001).
iv. the major role of feasibility studies, including both physical and seismic aspects, performed prior to repetitive seismic acquisition campaigns.

It finally specifically highlights the main issues tackled within this integrated study.

1.1: Definition of seismic reservoir monitoring

Seismic reservoir monitoring (time-lapse seismic) is defined as the process of repeating seismic surveys over a reservoir in time-lapse mode to look for differences caused by production (Lumley and Behrens, 1997). When hydrocarbons are recovered from reservoirs, the elastic properties of the reservoir rock change. This is due to the variations of reservoir parameters, such as fluid saturation, fluid pressure, stress distribution or temperature. As a consequence of these changes, seismic reservoir attributes, such as amplitudes, phases or two-way travel-times may also vary. If these variations are large enough to be seismically detected, comparing repetitive seismic surveys may allow mapping these reservoir property changes. Seismic provides the largest source of information about the underground that has not been accessed by drilling, and as such the potential results of seismic data comparisons are tremendous. They allow, for example, monitoring hydrocarbon saturation fronts, pressure changes, detecting bypassed hydrocarbon areas or internal reservoir heterogeneity features, such as barriers to fluid flow, sealing faults, pressure compartmentalization. Seismic reservoir monitoring can also therefore greatly contribute to refine the description of reservoirs.
1.2: Seismic reservoir monitoring for reservoir management

By providing data not only for delineating reservoir structures as seismic is commonly used for exploration, but also for deriving reservoir internal properties, seismic reservoir monitoring acts as a strategic tool for detailed reservoir modelling and reservoir characterization. It provides the ability to constrain and update dynamic reservoir models, such as geostatistical flow simulator models, with two types of independent information: production data (water cut, fluid production rates, Repeat Formation Tester (R.F.T.), well testing) and seismic data. Uncertainties on reservoir modelling are therefore reduced, allowing producible reserves to be increased (for example by producing hydrocarbons from old fields or by delaying field abandonment) and operating costs to be decreased (Lumley and Behrens, 1997). Figure 1.3 illustrates a possible workflow for integrating reservoir geophysics and reservoir engineering disciplines, and many publications have illustrated the benefit of such a synergy for improving reservoir management (Archer et al., 1993; Gawith et al., 1995; Anderson et al., 1998; Waggoner, 1998b; Huang et al., 2000).

![Figure 1.3: Data integration workflow (from Lumley and Behrens, 1997).](image-url)
Moreover, linking reservoir flow simulator output data to seismic data also brings a step forward to go from qualitative analysis to quantitative analysis of dynamic changes within reservoirs (Waggoner, 1998a). This requires a strong understanding of the relationships between reservoir rock parameters (porosity, permeability, mineralogy, clay content) and fluid parameters (compressibility, pore pressure, saturation) on one hand, and seismic signatures on the other hand. The building of such relationships falls within the competence of the rock physics discipline.

1.3: The synergy between laboratory experimental research and time-lapse seismic studies

The concept that reservoir rocks are elastically sensitive to reservoir condition changes, such as fluid saturation, confining pressure, pore pressure or temperature is known for many decades, and has been described by many theoretical and experimental works. Gassmann (1951), Wyllie et al. (1956), Nur and Simmons (1969b), Domenico (1976), Gregory (1976), among others, have reported the fluid saturation dependence of elastic wave velocities. Mindlin (1949), King (1966), Nur and Simmons (1969a) have reported the pressure dependence of elastic wave velocities, whereas Timur (1968; 1977) has studied their temperature dependence.

These works have progressively contributed to bring forward the possibility of monitoring dynamic reservoir changes by comparing repetitive seismic surveys. The first seismic reservoir monitoring surveys were then initiated in the early eighties (Waggoner, 1998a), and their number began to increase in the mid-90's. Among the first successful published case studies were for example the Oseberg Field (Johnstad et al., 1993; 1995) and the Magnus Field (Watts et al., 1996; Gawith and Gutteridge, 1996). At the same time, ongoing theoretical and experimental research performed
within universities, research centres and research institutes have still contributed to the promotion of the application of seismic reservoir monitoring to reservoir fields. Recent works for example, have focused on the building of relationships between rock frame elasticity and porosity as a function of the texture of the rock, the clay content, for different confining pressure levels (Best et al., 1994; Vernik, 1994; Vernik, 1997; Khazanehdari et al., 1998; Khaksar et al., 1999). Other works have described the effects of the fluid saturation distribution on compressional wave velocities on partially saturated rocks (Goertz and Knight, 1998; King et al., 2000). Jones et al. (2001) have reported that wave attenuation can be more sensitive to fluid saturation changes than wave velocity. Such studies have allowed quantification of both pressure and fluid saturation effects on elastic wave velocities at the sample scale. This has also promoted the use of time-lapse Amplitude Versus Offset technique (Bush et al., 2000; Hall and MacBeth, 2001) and the potential use of multi-component data for time-lapse analysis to decouple pressure from fluid saturation effects on the overall time-lapse seismic response.

As a consequence of these various studies, the successful number of seismic reservoir monitoring case studies has increased. Recent cases include for example the Alba Field (MacLeod et al., 1999), the Gulfaks Field (Landrø et al., 1999), the Lena Field (Johnston et al., 2000), the Troll West Field (Elde et al., 2000), or the Snore Field (Smith et al., 2001). Oil companies and contractors are continuously gaining in experience from these various case studies, for example Jack (2001) has reported the need to shorten the time-interval between surveys, as dynamic effects might be seismically seen at the very early stage of production.
1.4: Feasibility studies for seismic reservoir monitoring

Success of seismic reservoir monitoring depends mainly on the ability of seismic to detect reservoir changes caused by production. Estimating the possible chances of success for such changes to be seismically detected, prior to the acquisition of repetitive seismic data, is necessary. This is the objective of feasibility studies. Nur (1989), Lumley et al. (1997), Wang (1997) have listed the main parameters to be investigated within such feasibility studies. Two main aspects predominate in a feasibility study: the physical aspect and the seismic aspect. Both are presented as follows.

The physical aspect is related to both the nature of the recovery process and the reservoir properties. Nur (1989) has classified the main reservoir properties in four different types:

- the rock mineralogy, that is the composition of the reservoir rock including the elastic moduli of its components;
- the rock properties (elastic moduli of the rock frame, porosity, permeability to fluids); the lower the rock frame elastic moduli and the higher the rock porosity, the more sensitive the rock elasticity to reservoir changes due to production;
- the fluid properties (fluid compressibility, hydrocarbon chemistry, bubble point pressure, fluid viscosity, gas-oil ratio, formation volume factor); the larger the difference in compressibility between fluids, the higher the chance to seismically monitor fluid movements;
- the environmental factors (pore pressure, stress, temperature); the larger the changes of these parameters, the higher the chance to seismically monitor reservoir elastic variations.
Reservoir changes and the ability of seismic to detect them are also controlled by the nature of the recovery process (water injection, gas injection, pressure depletion, gas production, steam injection). For example, steam injection leads to a large decrease of fluid viscosity and compressibility. It would therefore produce a different time-lapse response and would have a different hydrocarbon recovery efficiency than a recovery by water injection.

Figure 1.4 illustrates the possible effects on compressional wave velocity resulting from various hydrocarbon recovery processes. It highlights that pressure and fluid saturation effects on wave velocities can add up or eliminate each other, which emphasises the necessity to decouple them.

![Figure 1.4: Variation of reservoir compressional wave velocity with pore pressure for different production scenarios (from Waggoner, 1998a).](image)

The seismic aspect deals with resolution and detection issues on one hand, and with repeatability and processing issues on the other hand.

The limit of seismic resolution, which depends on both frequency and noise data content, is defined as the minimum separation for two features to be seismically distinguished. The limit of seismic detection is defined as the minimum size of a feature or contrast in property that produces a measurable seismic response (King,
1996). It signifies that it is therefore possible to detect reservoir changes within layers, which is the objective of time-lapse analysis, without resolving both top and bottom of these layers. According to King (1996), this provides an extra factor of around 5, allowing for example to detect changes in beds of 6 meter thick for a resolution limit of 30 meters. Moreover, when comparing seismic data from different surveys, the main differences, if any, have to be attributable to reservoir exploitation and not to seismic acquisition or processing. It is therefore necessary to ensure a good repeatability between seismic surveys. The use of ocean bottom cables for marine acquisitions (Beasley et al., 1997), and the technique of processing seismic data using a common workflow (Ross and Altan, 1997) help in this matter.

Finally, according to Lumley et al. (1997), and as a general rule of thumb for feasibility studies, reservoir changes are expected to be seismically detected if feasibility studies predict impedance changes due to production larger than 4%, or seismic travel-time changes larger than four time seismic data samples.

1.5: Limits of the present state of the art

Section 1.3 has shown that seismic reservoir monitoring, by its various successful case studies, is now established as a useful tool to help mapping reservoir changes due to production and to increase hydrocarbon recovery. However, there is still a need for more research to be carried out in this emerging area, as the majority of time-lapse studies remains based on qualitative rather than on quantitative analysis. Many issues explain the limits preventing quantitatively relating pressure and saturation changes to real seismic data. Two of such issues are specifically tackled within this integrated study: one is related to rock physics (Chapters 2 and 3), the other being related to the elastic modelling from flow simulation models (Chapters 4 and 5).
1.5.1: The rock physics issue

Concerning the rock physics aspect, one main issue is the lack of exhaustive rock physics theory allowing modelling elastic wave velocities directly from the petrophysical properties of a given rock fabric (Murphy et al., 1993; Nes et al., 2000). This is mainly explained by the large number of petrophysical parameters controlling the elasticity of a rock, as described by Anstey (1991). Such parameters include cementation, consolidation, grain shape (angularity, roughness), sorting, overburden pressure, rock type, or clay content. The location of the clay particles within the pore network (either free within the pore space, or tightly packed in the pores, or intruded between grains) also influences the elasticity of a rock (Anstey, 1991). The nature and the location of the cement (at grain-to-grain contacts or around the grains) are other factors controlling the rock elasticity (Dvorkin and Nur, 1996). The influence of cementation on the rock frame elasticity has been theoretically investigated by Dvorkin et al. (1994b), independently of their pressure dependence though.

Moreover, porosity is a key petrophysical property as it allows estimating the amount of hydrocarbon present in the reservoir. A general trend between porosity and elasticity exists, as high wave velocities correspond to low porosity whereas low wave velocities correspond to high porosity. However, within these two bounds, data are very often scattered suggesting that the link between elasticity and porosity is more incidental than causal (Anstey, 1991). This is illustrated by examples of wave velocity-porosity-clay content relationships (Han et al., 1986), or $V_p/V_s$-porosity relationships (Tatham, 1982; Anstey, 1991): the amount of scatter among data prevents such relationships to accurately predict the rock elasticity. This is explained by the large number of parameters influencing the rock elasticity and by their interdependence. The soft porosity of a rock (by opposition to its hard porosity) also contributes to this scatter. Dvorkin et al. (1996) have indeed reported, in the case of clean sandstones, that soft
porosity (compliant cracks, grain-to-grain contacts) hardly contributes to the total amount of rock porosity but strongly reduces the rock stiffness, depending on the effective stress levels. These various contributions to the rock physics knowledge and the large number of models resulting from experiments carried out on core samples indirectly suggest that there is no exhaustive theory predicting the rock elasticity from petrophysical parameters, resulting from a thin section analysis for example.

Laboratory measurements for feasibility studies are performed on a limited number of core samples, which raises the question of how accurately these core samples represent the corresponding reservoir. This issue is mainly function of the scale of the reservoir heterogeneity, which depends on the depositional environment of the sediments. Sedimentological characteristics of a reservoir can be very accurately described, based on outcrop analogue studies for example. However, even in such a favourable case, the absence of unified theory relating the whole petrophysical parameters to the rock elasticity prevents accurate predictions of the pressure and fluid dependencies of the rock elasticity at the scale of the whole reservoir. This therefore prevents quantitative time-lapse analysis to be performed at the scale of the whole reservoir from measurements performed on a few core samples only. As wave velocities measure the overall combination of all of the petrophysical parameters forming a rock, it is critical to individually tackle the influence on the rock frame elasticity of petrophysical parameters that are heterogeneously distributed within reservoirs, by decoupling their effects. This issue has thus motivated, in Chapters 2 and 3, the investigation of the effect of both consolidation and cementation on a set of core samples collected from the same site, the Lochaline mine. Samples have similar grain mineralogy, are free of clay, and cover a large range of porosity: only their degrees of consolidation and cementation differentiate them.
1.5.2: The effect of the size of the flow simulator grid block on the elastic response

The second aspect investigated in this dissertation preventing time-lapse analysis to be quantitatively carried out is related to the vertical size of the grid blocks of the flow simulation models.

The effect on the flow simulation results of the increase of the size of the grid blocks to optimise the simulation running time is usually taken into account by upscaling the petrophysical properties to compensate for numerical dispersion while preserving small scale geological features. However, the influence of the grid block size on the elastic response modelled from the flow simulation results and derived to be matched with real seismic data is currently rarely considered. It actually leads to errors on the modelled elastic response due for example to geometrical artefacts, as a model built with coarse grid blocks does not fit the geometry of a reservoir as accurately as a model with fine grid blocks. Another artefact is that flow simulation models artificially smooth parameters, such as pore pressure or fluid saturation when coarse grid block are used, as these properties are averaged within cells. Possible heterogeneities of such properties at a scale smaller than the grid blocks can be thus artificially smoothed and therefore properties may be perceived as homogeneous within the grid blocks. However, heterogeneity of fluid saturation distribution at a scale smaller than the seismic resolution can lead to a different seismic response than the response assuming a uniform fluid saturation distribution (Knight et al., 1998; Mavko and Mukerji, 1998). The synthetic seismic response derived from flow simulation models and thus the quality of its match with real seismic data therefore depends on the vertical size of the grid block.

Some of these aspects have been investigated in the literature. Sengupta and Mavko (1998) have presented a methodology to scale-up the acoustic signatures of fluid
saturation from the sub-resolution seismic scale to the scale of a seismic pixel. This has been carried out on dynamic fine grid models of the size of a seismic pixel for various production scenarios. However, the analysis has not been performed at the scale of a whole reservoir because of the small size of the models. Sengupta et al. (2000) have showed in a real case study of gas injection that estimating sub-resolution fluid saturation heterogeneities from well log data could increase the quality of the match between the fluid changes predicted by the flow simulation and those interpreted from the seismic. However, there is no study in the literature focusing on the effects of fluid saturation heterogeneities on the acoustic signature at the sub-seismic scale, taken into account possible geological heterogeneities at the scale of a whole reservoir for different recovery processes.

The approach followed in Chapter 5 to tackle this specific issue when integrating rock physics measurements with flow simulation modelling has been as follows. It has consisted in creating two types of flow simulation models representing a real geological outcrop, with different grid block sizes, after appropriate upscaling of the petrophysical properties. The acoustic signatures derived from these two types of models representing the same outcrop have then been computed and compared to estimate their dependence upon the grid block size, the lithofacies type, the production scenario, the reservoir depth and the fluid properties.
Chapter 2: Rock Physics Experiments and Results

Evaluating the technical risk of seismic reservoir monitoring projects requires preliminary feasibility studies, including seismic resolution estimation, seismic repeatability evaluation and rock physics studies. Rock physics key role for time-lapse seismic feasibility studies consists in carrying out laboratory experiments on reservoir rock samples. These experiments allow determining elastic wave velocities, porosity and permeability of the core samples at various conditions of effective stress, fluid content and saturation level. Their main purpose is to quantitatively investigate how the dynamic elastic moduli are related to parameters which are dynamically linked with reservoir exploitation, such as effective stress and fluid saturation, stress-sensitivity of porosity and permeability. These laboratory experiments allow decoupling the effects of effective stress and fluid saturation on rock elastic wave velocities. By quantifying the expected variations of elastic wave velocities with reservoir production, rock physics studies help assessing the potential success of the application of the seismic reservoir monitoring technique on a field. This chapter presents both the experimental part and the results of a rock physics study that is used as the basis of the modelling of reservoir time-lapse effects. It describes successively the characteristics of the rock used in the laboratory, the preparation of the core samples, the laboratory equipment and the experimental procedure. It finally presents the main results of these experiments.
2.1: Description of the core samples

Samples have been collected from the Lochaline silica mine, Morvern, West Scotland (Figure 2.1), where Cretaceous shallow marine sandstones are exposed at outcrop and preserved in situ.

Lochaline Sandstone, which has experienced very little deformation and minimal diagenesis, possesses reservoir quality fluid flow characteristics (Lewis et al., 1990) which has made it a good analogue for shallow marine reservoirs. This white uniform sandstone is loosely consolidated, its ambient porosity is 0.19 and it is exceptionally clean as it contains more than 99.6% silica (Lewis et al., 1990). It is relatively well-sorted (very fine to medium grain size: from 0.040mm to 0.600mm), and its grain size distribution is centred at 0.200-0.250mm (Figure 2.2).
Grain roundness of this loosely consolidated sandstone distribution varies from angular to rounded (Humphries, 1961). Scanning Electron Micrograph (S.E.M.) analysis on thin sections highlights both the partial-absence of clay and the absence of cementation (Figures 2.3 and 2.4). Pressure dissolution sutures are detected at grain-to-grain contacts (Figure 2.5) and prevent this loosely consolidated sandstone from falling apart. A few fractured grains also indicate that the sandstone has undergone a slight compaction. These characteristics allow the Lochaline Sandstone to be manually disaggregated and thus transformed into a pure unconsolidated sand without altering the characteristics of the non fractured grains. Grain size, grain angularity, and grain roughness are therefore similar for both loosely consolidated and unconsolidated samples.

Hard lenses of rock, with different petrophysical properties, but from an identical primary depositional process, are also present within this Lochaline Sandstone. In these lenses, the sandstone is well-cemented, with an ambient porosity of 0.05, due to concentrated post-depositional silica cementation, as the result of water table fluctuation (Lewis et al., 1990). Figure 2.6 illustrates quartz overgrowth features in this well-
cemented sandstone. Comparison of S.E.M. analysis of thin sections cut in two perpendicular planes from a same core sample does not highlight any sign of heterogeneity or anisotropy for both the loosely consolidated and well-cemented sandstones.

![Figure 2.3: S.E.M. photograph of the loosely consolidated sandstone. No discernible cementation or clay traces.](image)

Figure 2.3: S.E.M. photograph of the loosely consolidated sandstone. No discernible cementation or clay traces.

![Figure 2.4: S.E.M. photograph on a thin section of the loosely consolidated sandstone. No discernible cementation or clay traces. Illustration of intra-granular cracks.](image)

Figure 2.4: S.E.M. photograph on a thin section of the loosely consolidated sandstone. No discernible cementation or clay traces. Illustration of intra-granular cracks.
The Lochaline mine thus provides a unique data set for comparing identical measurements performed on loosely consolidated, well-cemented and unconsolidated core samples, collected from the same initial sandstone type. Indeed, parameters, such as grain size distribution, grain sorting, grain roughness, grain roundness, clay content, which form the texture of the rock, generally vary from sample to sample, and can greatly affect the petrophysical and elastic properties of the rock. This generally makes it difficult to decouple the effects of these parameters on rock elastic properties when comparing measurements carried out on core samples collected from various places. In
this study, as all the samples come from the same sandstone type, these parameters are similar. Consolidation and cementation are the only factors varying among these samples. They mainly affect their grain-to-grain contact characteristics and therefore both their elastic wave velocities and rock properties, such as porosity and permeability.

Samples collected from the Lochaline mine, offer the challenge to study and compare the effects of consolidation and cementation, two main diagenetical processes affecting reservoir rocks, on elastic wave velocities, porosity, and permeability at various effective stress conditions. Lochaline Sandstone is consequently an ideal candidate to carry out rock physics experiments for time-lapse feasibility studies of shallow marine reservoir analogues.

2.2: Preparation of the samples

2.2.1: Loosely consolidated sandstones

Seven samples have been drilled from three different blocks of loosely consolidated sandstone for laboratory measurements. These three blocks were similar in appearance and no heterogeneity or anisotropy within the blocks were detected. Samples were therefore considered to be homogeneous and isotropic. The average length and diameter of the cylindrical samples were 110mm and 55mm.

As these samples were very friable, their edges were not totally regular, so their geometry deviated slightly from the geometry of a perfect smooth cylinder. Porosity and permeability therefore could not be calculated properly using the classical porosimeter and permeameter tools, as these tools require the shape of the tested sample to be perfectly cylindrical. However, as porosity and elasticity of rocks are linked, it was necessary to accurately determine the porosity of the samples at ambient pressure.
(one atmosphere) before beginning the rock physics experiments. The procedure described as follows was adopted on each of these eight samples to calculate their porosity:

i. dry the sample by putting it in an oven at a temperature of 104°C for a minimum of 24 hours;

ii. measure the weight of the dry sample (\(W_d\));

iii. saturate the sample with distilled water using a vacuum pump to extract all the air from the sample pores for a minimum of three hours;

iv. measure the weight of the sample saturated with distilled water (\(W_s\));

v. measure the density of the distilled water (\(\rho_w\));

vi. measure the weight of the saturated sample when immersed in distilled water and calculate its total volume (\(V_t\)) using Archimedes principle.

Lochaline Sandstone, as a clean material, is made of two distinct parts: its grain (pure quartz only), and its pores. Its grain density is therefore identical to the grain density of the quartz, which is 2.65g/cm\(^3\) (Carmichael, 1982). Measured parameters (\(V_t, W_d, W_s, \rho_w\)) and the grain density (\(\rho_m\)) are related to the total volume of the pores (\(V_p\)) and to the total volume of the grains (\(V_m\)) by the following relationships:

\[
V_t = V_p + V_m, \tag{2.1a}
\]

\[
W_d = \frac{\rho_m}{V_m}, \tag{2.1b}
\]

\[
W_s = \frac{\rho_w}{V_p} + \frac{\rho_m}{V_m}. \tag{2.1c}
\]
Porosity ($\phi$) is defined as the ratio of the pore volume to the total volume of the sample:

$$\phi = \frac{V_p}{V_p + V_m} = 1 - \frac{V_m}{V_t}. \quad (2.2)$$

From these two sets of equations (2.1 and 2.2), porosity was finally computed using the following four different formulae:

$$\phi_1 = \frac{\rho_m (W_s - W_d)}{\rho_m W_s - (\rho_m - \rho_w) W_d}, \quad (2.3a)$$

$$\phi_2 = \frac{\rho_w (W_s - W_d)}{V_t}, \quad (2.3b)$$

$$\phi_3 = \frac{\rho_m V_s - W_d}{(\rho_m - \rho_w) V_t}, \quad (2.3c)$$

$$\phi_4 = \frac{\rho_m V_t - W_d}{\rho_m V_t}. \quad (2.3d)$$

$\phi_1$, $\phi_2$ and $\phi_3$ correspond to the total porosity whereas $\phi_4$ refers to the effective porosity of the sample. For a given sample, these four formulae (each of them using a different combination of parameters) led to similar results for porosity, the largest difference never reached 1%. No distinction between effective porosity and total porosity was therefore considered. The final sample porosity was computed as the arithmetic average of these four values. Computing porosity values with these four different relationships and comparing results also allowed checking the accuracy of the final porosity value. Average ambient porosity of the loosely consolidated Lochaline Sandstone was close to 0.19.
2.2.2: *Well-cemented sandstones*

A different process was adopted on the sample extracted from a block of well-cemented sandstone. In this case, the sample was not friable, and its shape was one of a perfect cylinder. Porosity could therefore be calculated directly on sister plug using the porosimeter tool. The absolute permeability using the gas permeameter tool was calculated on this well-cemented sandstone sample, it was corrected for gas slippage (Klinkenberg correction). Ambient porosity of the well-cemented sandstone was 0.05 and its absolute permeability was 5mD, at ambient condition.

2.2.3: *Unconsolidated sands*

For the unconsolidated sands, careful preparation was adopted, before measuring porosity. Sample preparation procedure is presented as follows:

i. manually disaggregate a block of loosely consolidated sandstone;

ii. perform a sample grain size distribution analysis using a particle size analyser ("Mastersizer" laser light scattering-based);

iii. sieve a part of the disaggregated sample grains;

iv. separate the grains according to their size;

v. encapsulate the sand grains in an impermeable, solvent resistant heat-shrunk Teflon jacket, one millimetre thick, with open faces protected by stainless steel gauze, to ensure sample integrity during repeated handling and testing.
Two categories of sands were finally obtained:

- the disaggregated sands (no sorting upon the grain size distribution);
- the well-sorted sands (with sorting upon the grain size distribution, grain diameter size varying between 0.212mm and 0.250mm).

The average length and diameter of the cylindrical samples were 104mm and 52mm. Unconsolidated sample porosity was calculated using the same methodology as described in the case of the loosely consolidated sandstones in Section 2.2.1. Both weight and volume of the jacket and gauze were accounted for this process. Porosity of the unconsolidated sands at ambient condition was around 0.38.
2.2.4: Nomenclature of the samples

Table 2.1 presents the nomenclature of all the samples used for the experiments (loosely consolidated, well-cemented sandstones, and unconsolidated sands) with their corresponding ambient porosity values. Unconsolidated samples SU1, SU6 and SU10 are disaggregated sands (without sorting) whereas unconsolidated samples SU3 and SU9 are well-sorted sands.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Porosity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1</td>
<td>0.1873</td>
</tr>
<tr>
<td>1.2</td>
<td>0.1860</td>
</tr>
<tr>
<td>1.3</td>
<td>0.1890</td>
</tr>
<tr>
<td>1.5</td>
<td>0.1865</td>
</tr>
<tr>
<td>3.1</td>
<td>0.1845</td>
</tr>
<tr>
<td>3.2</td>
<td>0.1880</td>
</tr>
<tr>
<td>4.1</td>
<td>0.1910</td>
</tr>
<tr>
<td>SU1</td>
<td>0.3526</td>
</tr>
<tr>
<td>SU3</td>
<td>0.3895</td>
</tr>
<tr>
<td>SU6</td>
<td>0.3762</td>
</tr>
<tr>
<td>SU9</td>
<td>0.3831</td>
</tr>
<tr>
<td>SU10</td>
<td>0.3738</td>
</tr>
<tr>
<td>2.1</td>
<td>0.0500</td>
</tr>
</tbody>
</table>

Table 2.1: Nomenclature and ambient porosity values of the Lochaline samples.

Except for the well-cemented sandstone sample, no permeability measurements were carried out at ambient condition with the permeameter, as its use requires that the shape of a tested sample is one of a perfect cylinder. Absolute permeability values of the consolidated and unconsolidated samples were measured under effective stress increase during the experiments, as presented in Section 2.4.3.2.
2.3: Laboratory equipment

The equipment schematic is presented in Figure 2.7. The testing equipment consists of a servo-controlled stiff testing machine, a Hoek cell with confining pressure intensifier, a pore pressure intensifier, acoustic velocity transducers and datalogger.

Figure 2.7: Schematic of the laboratory equipment layout. Arrows indicate the direction of the axial load.
2.3.1: Servo-controlled stiff testing machine and pressure intensifier

The stiff testing machine is an RDP Howden servo-controlled hydraulic machine rated to 1000kN axial load. It consists of a straining frame that holds an hydraulic ram, several platens and a load cell. The ram operates vertically with the load cell located in the crosshead of the straining frame. The position of the ram is monitored electronically by a linearly variable differential transformer (L.V.D.T.) connected to it, and this signal together with the signal from the load cell allows the flow of hydraulic oil to the ram to be controlled. Thus the load and rate of loading are controlled. Associated with the stiff testing is a pressure intensifier. This uses the same principles (and hydraulic circuit) to control the confining pressure in the Hoek cell. A second pressure intensifier is used to supply pore pressure to the sample via porous end platens, within are located the acoustic velocity transducers.

2.3.2: Hoek cell

The cell provides a means of applying confining pressure to the core samples. It consists of a steel cylinder rated to 68.9MPa (10,000psi) within which is located a polyurethane sleeve. Hydraulic oil fills the annulus between the body of the cell and the sleeve. The core sample is located within the sleeve and the hydraulic oil is pressurised by a connection to the intensifier. It is then mounted in the loading frame between steel platens of the same diameter of the sample. The pressure and volume of the oil introduced or removed from the cell during the tests are monitored electronically by the testing machine to ensure a constant pressure. Figure 2.8 is a photograph of the cell and of the platens and Figure 2.9 presents the testing equipment during an experiment.
2.3.3: Acoustic velocity transducers

An acoustic transmitter and receiver are positioned either side of the sample in each of the steel platens. A piezoelectric transducer is excited by a 400V pulse generator. This produces a pulse of either compressional or shear waves that propagate across the sample. The compressional and shear wave velocities (elastic wave velocities),
respectively centred at 600kHz and 700kHz, are measured using time-of-flight of an ultrasonic pulse. A second transducer converts the strain wave to an electronic signal. Waveforms are averaged to increase the signal-to-noise ratio. They are then amplified and recorded on a digital storage oscilloscope. Waveforms are finally downloaded onto a PC to be processed.

2.4: Experimental procedure

Three major series of tests were performed on the Lochaline samples at various levels of effective stress, fluid content and saturation. Tests can be classified into the three following categories (Kirstetter et al., 1999):

- dry frame tests;
- petrophysical tests;
- pore fluid tests.

2.4.1: Effective stress and differential pressure

Effective stress ($\sigma_e$) is defined as follows (Fjaer et al., 1992):

$$\sigma_e = \sigma_t - \beta p_f,$$

with $\sigma_t$ the total external stress, $p_f$ the fluid pressure and $\beta$ the Biot constant.

The Biot constant ($\beta$) is defined as follows (Fjaer et al., 1992):

$$\beta = 1 - \frac{K_d}{K_m},$$

with $K_d$ the bulk modulus of the dry frame and $K_m$ the bulk modulus of the mineral making up the rock.
Differential pressure (\( \sigma \)) is defined as the difference between the total external pressure (\( p_t \)) and the fluid pressure (\( p_f \)):
\[
\sigma = p_t - p_f.
\] (2.6)

For all types of experiments carried out, the loading regime was hydrostatic. This means that the three major external stresses (the axial stress and confining pressure, controlling the total stress level) were equal. Therefore, both concepts of stress and pressure are similar in this particular hydrostatic test configuration. By assuming a Biot constant equal to 1 (valid if \( K_d << K_m \)), effective stress and differential pressure are identical. This assumption is used in this study, and either the term effective stress or the term differential pressure (or pressure) will be used without any distinction in this thesis.

2.4.2: Dry frame tests

A small amount of water was initially introduced within the samples before dry frame experiments. These tests were therefore performed not on completely dry samples, but on "moist" samples with a water saturation level varying between 5% and 7% (Zinszner, 1999). The reason for keeping a minimum level of water saturation within the samples for these dry frame tests was to avoid any ultradry rock artefacts (Mavko et al., 1998). Introducing a small amount of water (smaller than 5% of the sample pore volume) in an ultradry rock can lead to the phenomenon of adsorption which lowers the surface energy at grain-to-grain contacts, and might also produce cement softening or clay swelling (Mavko and Mukerji, 1998). As this surface energy generates a cohesive traction between the grains, a small amount of water decreases the rock stiffness (Murphy et al., 1984). Elastic wave velocities therefore sharply decrease with a small amount of water introduced into a sample totally dried (Figure 2.10). As reservoir rocks
are never completely dry in reality, these ultradry rock effects which might occur in the laboratory have to be avoided and corrected for. This was performed by carrying elastic wave measurements on “moist” samples, and extrapolating the slightly wet rock elastic moduli to a water saturation level of zero to compensate for the water density effect. This is illustrated by Figure 2.10 in the case of the compressional velocity. The extrapolated elastic moduli are thus considered to represent the elastic moduli of the rock frame (the rock frame being defined as the rock with empty pores). These elastic moduli can then be used as input into fluid substitution relations (Cadoret, 1993; King et al., 2000), such as Gassmann’s relations (Gassmann, 1951), described in Section 3.2.1.

![Figure 2.10: P-wave velocity versus water saturation (from Mavko et al., 1998).](image)

Water saturation ($S_w$) is calculated given the weight of the sample ($W_m$), the weight of the dry sample ($W_d$), and the weight of the fully water saturated sample ($W_s$), by the following equation:

$$S_w = \frac{W_s - W_m}{W_s - W_d}. \quad (2.7)$$

$S_w$ was consequently controlled using Equation 2.7 by continuously weighing the sample during the drying process. When the final saturation level was reached (between 5% and 7%), the sample was placed into a closed plastic bag for a minimum of 24 hours.
to let the water homogeneously distribute within the sample by capillary force equilibrium. The sample was then put in the Hoek cell, for both P- and S-wave travel-times to be recorded with increasing effective stress.

2.4.3: Petrophysical tests

In the context of seismic reservoir monitoring studies, as well as elastic wave velocities, porosity and permeability relationships with effective stress are important to determine. Porosity is an estimate of the amount of fluid that reservoir rocks can contain, whereas permeability measures the ability of a rock to pass fluid. These petrophysical tests consisted in measuring both porosity and permeability to oil with effective stress. Tested sample was initially saturated with dead oil (density of 0.867g/cm$^3$ and viscosity of 28cp at ambient condition), by immersing it in dead oil and extracting all the air from the pores using a vacuum pump, for a minimum of three hours. The sample was then put in the Hoek cell, and both axial load and confining pressure were increased. Pore pressure was kept at ambient pressure during the test. At each effective stress level, the change of porosity (pore volume squeeze-out) and permeability were successively recorded during the same experiment. P- and S-wave travel-times were also recorded.

2.4.3.1: Porosity

Porosity ($\phi_o$) at a given effective stress ($\sigma$) was calculated by measuring the pore volume squeeze-out with stress. Given the volume of the sample at ambient pressure ($V_i$), the porosity at ambient pressure ($\phi_i$), the total pore volume squeeze-out ($V_o$) at stress ($\sigma$), and the sleeve conformance volume ($\alpha$), porosity ($\phi_o$) was calculated by the following formula:

$$\phi_o = 1 - \frac{V_i(1-\phi_i)}{V_i - (V_o - \alpha)}.$$ (2.8)
\( V_i \) and \( \phi_i \) have been previously calculated as described in Section 2.2. The sleeve conformance volume (\( \alpha \)) was calculated by determining the sleeve conformance stress, i.e. the effective stress at which the sleeve conformed to the surface of the sample. This effective stress level corresponds to a major discontinuity of the expelled volume curve versus effective stress. The sleeve conformance volume value to be subtracted (\( \alpha \)) was then determined by extrapolating the curve to the zero effective stress axis. It was assumed that the grain volume of the samples remains constant with increasing effective stress.

2.4.3.2: Permeability

The pore volume squeeze-out having been measured, sample absolute permeability to dead oil was then also determined at the same effective stress level. The process was as follows. Dead oil was flowed through the sample at a rate of 1 milliliter per minute. When both flow rate and pressure drop across the sample were stabilised after injection of at least two pore volumes of dead oil, absolute permeability to dead oil was established at that effective stress, using Darcy’s law for a single-phase flow. Darcy’s law expresses the sample permeability (Darcy) as follows (Peaceman, 1977):

\[
k = \frac{QL\mu_0}{A\Delta P},
\]

with \( Q \) the flow rate (cm\(^3\)/s), \( \mu_0 \) the viscosity of the dead oil (cp), \( L \) the length of the sample (cm), \( A \) the cross sectional area of the sample (cm\(^2\)), and \( \Delta P \) the pressure difference (atm) measured across the sample.
2.4.4: Pore fluid tests

For this set of tests, P- and S-wave travel-times were recorded:

i. at varying fluid saturation levels, when injecting brine or dead oil or gas through the samples at a constant effective stress;

ii. when decreasing oil pressure on core sample saturated with dead oil, by keeping the total stress ($\sigma_t$) constant;

iii. when increasing oil pressure on core sample saturated with dead oil, by keeping the total stress ($\sigma_t$) constant.

This set of experiments, simulating field production scenarios at the sample scale, allowed estimating the effect of fluid saturation and fluid pressure changes on elastic wave velocities. They allowed either quantifying fluid effects on wave velocities, without any pressure changes, or quantifying pressure effects on wave velocities, without any saturation changes. In the case of the fluid substitution tests, saturation level of the injected fluid within the sample was calculated by volumetric estimation. The pore volume of the sample being known, volume of the injected fluid was then converted into saturation, taking into account irreducible water saturation, residual oil saturation to water and gas, estimated from Honarpour et al. (1986).

The salinity of the brine used during this test was 50,000ppm, similar to the salinity of typical brine of North Sea reservoirs, and its viscosity was 1cp. Dead oil was identical to the dead oil used for the petrophysical tests (density of 0.867g/cm$^3$ and viscosity of 28cp at ambient condition). Its density and bulk modulus were given by the oil manufacturer. Methane was used as gas. Table 2.2 presents the density and bulk modulus values of these three fluids at ambient pressure, and at 27.6MPa, computed
using Batzle and Wang’s equations (Batzle and Wang, 1992). Table 2.2 shows that both fluid density and bulk modulus are pressure dependent.

<table>
<thead>
<tr>
<th></th>
<th>Density (g/cm$^3$)</th>
<th>Bulk modulus (GPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Ambient condition</td>
<td>Ambient condition</td>
</tr>
<tr>
<td>Brine</td>
<td>1.032</td>
<td>2.443</td>
</tr>
<tr>
<td>Dead oil</td>
<td>0.867</td>
<td>1.740</td>
</tr>
<tr>
<td>Methane</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 2.2: Bulk modulus and density of the fluids used for both petrophysical and pore fluid tests.

2.4.5: Wave velocity measurement technique

P- and S-wave velocities were measured at ultrasonic wave frequencies using the pulse through-transmission technique (Birch, 1960). For each measurement, the corresponding P-wave travel-time or S-wave travel-time was downloaded onto a PC and its associated first-break (zero-crossing) travel-time (respectively $\tau_p$ or $\tau_s$) was picked visually from the waveforms. Figure 2.11 shows typical P- and S-waveforms recorded through a loosely consolidated sandstone. Corrections were made for P- and S-wave travel-time delays ($\tau_p^*$ and $\tau_s^*$) through the transducers. They were computed by positioning the transmitter and the receiver side to side without any sample between them. Figure 2.12 presents P- and S-waveforms used to determine $\tau_p^*$ and $\tau_s^*$. P- and S-wave velocities were then computed given the value of the initial length (L) of the sample, corrected by the shortening of the sample length ($\Delta L$) with increasing effective stress. $\Delta L$ was deduced from the position of the ram monitored electronically. Wave velocities ($V_p$) and ($V_s$) were finally calculated using the following formulae:

\[
V_p = \frac{L - \Delta L}{\tau_p - \tau_p^*},
\]

\[
V_s = \frac{L - \Delta L}{\tau_s - \tau_s^*}.
\]
Figure 2.11: Example of P- and S-waveforms (loosely consolidated sandstone).

Figure 2.12: P- and S-waveforms for transducer to transducer travel-time delay correction.

There was no ambiguity concerning the type of wave velocity (group velocity or phase velocity) of the recorded travel-times. Indeed, as no feature of intrinsic anisotropy was detected on the three types of Lochaline samples, and as the loading was constantly hydrostatic, both group and phase velocities were the same (Dellinger and Vernik, 1992).
2.4.6: Time-dependent effects

The increase of axial load and confining pressure applied on the sample during experiments led to reductions of both sample length and sample porosity, and therefore led to reduction of the total volume of the sample. This is the compaction effect. This compaction does not refer to the compaction due to rock burial during geological time. It refers to a short-time compaction of the sample due to the increase of effective stress in the laboratory (Toksoz et al., 1976). However, depending on the strength of the tested material, compaction can continue even if the axial load and confining pressure levels are stabilised. This effect is the largest for the unconsolidated sands, it is smaller for the loosely consolidated sandstones, and is negligible for the well-cemented sandstone.

In order to ensure that measurements were carried out on mechanically stable samples without undergoing any compaction, the following experimental rules were applied (Somerville, 1999). For the unconsolidated sands, a waiting time of 15 minutes was observed between a change in the stress state and the corresponding measurement, at a given effective stress value. For the loosely consolidated sandstones, a waiting time of 5 minutes was observed, as their strength was larger, and for the well-cemented sandstone, a waiting time of only 2 minutes was observed. Monitoring the shortening of the sample length with time during testing allowed controlling this sample mechanical compaction effect. Shortening of the length of the core samples as a function of effective stress for both loosely consolidated sandstone and unconsolidated sand (with sorting upon the grain size distribution) is illustrated by Figure 2.13.
2.5: Measurement error estimation

2.5.1: Concepts

Error is associated with any type of measurement. Before presenting the results of the experiments, estimation of the error associated with P- and S-wave velocities, porosity and permeability is discussed.

Quantification of errors is estimated using the uncertainty relations presented in Taylor (1997). Notation used by Taylor to estimate the measured value of a quantity \( x \), given the best estimate \( x_{\text{best}} \) and the uncertainty or error of the measurement \( \delta x \), is as follows:

\[
x = x_{\text{best}} \pm \delta x.
\]  

The fractional uncertainty is then defined as:

\[
\frac{\delta x}{|x_{\text{best}}|}.
\]
With $q$ the sum and/or the difference of terms $x, z, u, w$:

$$q = x + ... + z - (u + ... + w),$$

the uncertainty associated with independent random errors is:

$$\delta q = \sqrt{(\delta x)^2 + ... + (\delta z)^2 + (\delta u)^2 + ... + (\delta w)^2}. \quad (2.12)$$

With $q$ the product and/or the quotient of terms $x, z, u, w$:

$$q = \frac{x \times ... \times z}{u \times ... \times w},$$

the fractional uncertainty associated with independent random errors is:

$$\frac{\delta q}{|q|} = \sqrt{\left(\frac{\delta x}{x}\right)^2 + ... + \left(\frac{\delta z}{z}\right)^2 + \left(\frac{\delta u}{u}\right)^2 + ... + \left(\frac{\delta w}{w}\right)^2}. \quad (2.13)$$

These two sets of formulae allow calculating the fractional uncertainty of the quantities measured in the laboratory (P- and S-wave velocities, porosity and permeability).

### 2.5.2: P- and S-wave velocities

The uncertainty of the elastic wave velocities is associated with two different uncertainties: the uncertainty of the total length of the sample, and the uncertainty of the total travel-time of the wave.

For the fractional uncertainty of the total length of the sample ($L_t$), $\frac{\delta (L_t)}{|L_t|}$ is estimated to:

- 0.002 for consolidated samples;
- 0.010 for unconsolidated samples.

The relatively large fractional uncertainty of the length of the unconsolidated sands is due to their low stiffness: a small increase of axial loading significantly reduces their length.
Concerning the total travel-time of the wave \( \tau_i \), \( \frac{\delta \tau_i}{|\tau_i|} \) is estimated for both the loosely consolidated and well-cemented sandstones to:

- 0.010 for dry or fluid-saturated sample P-wave velocity;
- 0.015 for dry sample S-wave velocity;
- 0.018 for fluid-saturated sample S-wave velocity.

Concerning the total travel-time of the wave \( \tau_i \), \( \frac{\delta \tau_i}{|\tau_i|} \) is estimated for unconsolidated sands to:

- 0.018 for fluid-saturated sample P-wave velocity;
- 0.020 for dry sample P-wave velocity;
- 0.020 for dry sample S-wave velocity.

Fractional uncertainty of wave velocities is however larger at low values of effective stress, and are hard to estimate precisely. This is due to the degradation of the waveform quality at low effective stress levels. This concerns wave velocities recorded at effective stress lower than:

- 2.8MPa (400psi) for P-wave velocity;
- 4.1MPa (600psi), for loosely consolidated sandstone S-wave velocity;
- 5.5MPa (800psi), for unconsolidated sand P-wave velocity;
- 6.9MPa (1000psi), for unconsolidated sand S-wave velocity.
Figure 2.14 shows examples of P-waveforms recorded through a dry loosely consolidated sandstone at effective stress of respectively 20.7MPa, 5.4MPa and 2.7MPa. They highlight the waveform quality deterioration with decreasing effective stress and therefore the increase of the uncertainty of the picking of the first zero-crossing arrival time.

![Figure 2.14: Examples of P-waveforms recorded at three different effective stress levels (loosely consolidated sandstone).](image)

To summarise, the estimated uncertainties of the recorded wave velocities on both the loosely consolidated and well-cemented sandstones were:

- 2% (±1%) for P-wave velocity calculated on dry or fluid-saturated sample;
- 3% (±1.5%) for S-wave velocity calculated on dry sample;
- 3.6% (±1.8%) for S-wave velocity calculated on fluid-saturated sample.
For the unconsolidated sands, the estimated uncertainty of the recorded wave velocities was:

- 4% (±2%) for P-wave velocity calculated on fluid-saturated sample;
- 4.4% (±2.2%) P- and S-wave velocities calculated on dry sample.

Picking wave travel-times being an interpretative process, the repeatability of the picking is questionable. However, a fundamental remark is that these uncertainties correspond to absolute uncertainties. Relative uncertainties, defined as the uncertainty of one measurement in comparison with the same measurement performed on the same sample (but at another effective stress or fluid saturation levels) are considerably smaller. This is due to the fact that waves measured on the same sample for small changes of effective stress or saturation levels have a similar shape, which allows monitoring accurately the change of the shape of the wave during experiments. Thus, by keeping the same coherence when picking travel-time picking first arrival, relative measurements could be performed very accurately. Relative uncertainty was estimated to 0.4% (±0.2%) for the three types of samples (loosely consolidated, well-cemented sandstones and unconsolidated sands).
This is illustrated by Figure 2.15 in the case of the loosely consolidated sandstone. This signifies that changes of wave velocity values due to the evolution of effective stress or fluid saturation levels, which are those of interest for seismic reservoir monitoring feasibility studies, were monitored with a high precision. In the case of dry frame tests, waveforms were recorded every 1.4MPa effective stress increase until 16MPa and then every 2.8MPa, for the majority of the samples, to ensure high quality data.

**Figure 2.15:** Absolute uncertainty and relative uncertainty on P-wave travel-time (loosely consolidated sandstone). The relative uncertainty is much smaller than the absolute uncertainty.
2.5.3: Porosity and permeability

Fractional uncertainty of porosity is mainly associated to the uncertainty of porosity ($\phi_i$), and to the uncertainty of the pore volume squeeze-out ($V_o$), estimated to:

$$\frac{\delta \phi_i}{|\phi_i|} = 0.005,$$

$$\frac{\delta V_o}{|V_o|} = 0.02.$$

Fractional uncertainty of permeability is mainly associated to the uncertainty of the pressure drop ($\Delta P$) measured across the sample, estimated to:

$$\frac{\delta \Delta P}{|\Delta P|} = 0.02.$$

For porosity and permeability, uncertainty was therefore estimated to 4% (±2%).
2.6: Results

Table 2.3 presents the type of laboratory tests performed on each sample used for this feasibility study.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1</td>
<td>dry frame, fluid depressurization</td>
</tr>
<tr>
<td>1.1b</td>
<td>porosity/permeability, fluid pressurization</td>
</tr>
<tr>
<td>1.2</td>
<td>porosity/permeability</td>
</tr>
<tr>
<td>1.3</td>
<td>dry frame, fluid substitution, fluid depressurization</td>
</tr>
<tr>
<td>1.5</td>
<td>dry frame, fluid substitution</td>
</tr>
<tr>
<td>3.1</td>
<td>dry frame, fluid substitution</td>
</tr>
<tr>
<td>3.2</td>
<td>dry frame, fluid substitution</td>
</tr>
<tr>
<td>4.1</td>
<td>dry frame</td>
</tr>
<tr>
<td>SU1</td>
<td>fluid substitution</td>
</tr>
<tr>
<td>SU3</td>
<td>porosity/permeability</td>
</tr>
<tr>
<td>SU6</td>
<td>porosity/permeability</td>
</tr>
<tr>
<td>SU9</td>
<td>dry frame</td>
</tr>
<tr>
<td>SU10</td>
<td>dry frame</td>
</tr>
</tbody>
</table>

Table 2.3: Summary of the type of tests performed on each sample.

2.6.1: Dry frame tests

2.6.1.1: Nomenclature of samples and procedure

Dry frame tests were performed on nine different samples: samples 1.1, 1.3, 1.5, 3.1, 3.2 and 4.1 (loosely consolidated sandstones), sample 2.1 (well-cemented sandstone), and samples SU9 and SU10 (unconsolidated sand). Sample SU9 is a well-sorted unconsolidated sand whereas sample SU10 is an unconsolidated sand without any sorting upon the grain size distribution. Maximum effective stress value applied was 20.7MPa for samples 1.3, 1.5, 3.1 and 3.2, 48.2MPa for sample 1.1, and 67.5MPa for samples 2.1, 4.1, SU9 and SU10.
2.6.1.2: Elastic wave velocity relationships with effective stress

Plots of P- and S-wave velocity evolution versus effective stress for dry loosely consolidated, well-cemented sandstones, and unconsolidated sands are respectively presented in Figures 2.16 to 2.21. They show an increase of elastic wave velocities with effective stress for all samples. They highlight that their rate of increase with effective stress depends on the degree of consolidation and on the degree of cementation of the samples. No major difference of elastic wave velocity evolution with effective stress is noticed when comparing results from the unconsolidated sand samples SU9 and SU10.

![Figure 2.16: P-wave velocity versus effective stress (loosely consolidated sandstones).](image-url)

![Figure 2.17: S-wave velocity versus effective stress (loosely consolidated sandstones).](image-url)
Figure 2.18: P-wave velocity versus effective stress (well-cemented sandstone).

Figure 2.19: S-wave velocity versus effective stress (well-cemented sandstone).

Figure 2.20: P-wave velocity versus effective stress (unconsolidated sands).
Figures 2.16 and 2.17 illustrate that, despite a similar shape of wave velocity evolution as a function of effective stress between core samples, some variations of P- and S-wave velocities exist among this set of loosely consolidated sandstones. Ambient porosity values of the samples were very similar, as showed by Table 2.1, and all samples looked identical, as discussed in Section 2.1. No major petrophysical differences between these very clean sandstone samples were identified by thin section analysis. It is therefore unlikely that these differences are directly related to major variation of rock texture among samples, such as grain size, grain sorting, grain angularity, grain roughness, pore aspect ratio, or clay content. These differences are probably due to a combination of error measurements and small variations of some of these petrophysical properties among samples, not large enough to be directly quantified, but large enough to affect elastic wave velocities. This leads to the conclusion that any sample represents itself only, and relating reservoir properties to core properties measured in the laboratory on a unique sample is therefore likely to lead to discrepancies. It is more correct to estimate an average from data measured on several samples representing the same type of rock with similar petrophysical properties (in this case, the loosely consolidated sandstones), and to use this average to characterise the elastic parameters of this rock. Arithmetic and harmonic averages of wave velocities were computed for a given effective stress.
level, and both averages led to similar values. P- and S-wave velocities arithmetic averages as function of effective stress were finally selected and considered to represent the elasticity evolution as a function of effective stress of the dry loosely consolidated sandstones.

These arithmetic averages of elastic wave velocities are plotted on Figures 2.22 and 2.23, with the elastic wave velocities measured on sample 2.1 (well-cemented sandstone) and on sample SU10 (unconsolidated sand without any sorting upon the grain size distribution). These two figures highlight the dependence on both degrees of consolidation and cementation of the absolute elastic wave velocities and of their evolution with effective stress.

Figure 2.22: P-wave velocity versus effective stress (well-cemented sandstone, loosely consolidated sandstone and unconsolidated sand).
Table 2.4 summarises the main results concerning the stress-sensitivity of the elastic wave velocities for each type of dry samples (loosely consolidated and well-cemented sandstones, and unconsolidated sands).
### (a) Loosely consolidated sandstone

<table>
<thead>
<tr>
<th>Effective stress range (MPa)</th>
<th>$V_s$ increase (%)</th>
<th>$V_p$ increase (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.41 to 0.96</td>
<td>18.5</td>
<td>19.2</td>
</tr>
<tr>
<td>0.96 to 1.52</td>
<td>6.3</td>
<td>7.1</td>
</tr>
<tr>
<td>1.52 to 2.07</td>
<td>2.7</td>
<td>3.4</td>
</tr>
<tr>
<td>2.07 to 2.62</td>
<td>1.7</td>
<td>2.3</td>
</tr>
<tr>
<td>2.62 to 3.17</td>
<td>0.9</td>
<td>1.5</td>
</tr>
<tr>
<td>3.17 to 3.72</td>
<td>0.7</td>
<td>0.9</td>
</tr>
<tr>
<td>3.72 to 4.27</td>
<td>0.6</td>
<td>0.8</td>
</tr>
</tbody>
</table>

### (b) Unconsolidated sand (with sorting)

<table>
<thead>
<tr>
<th>Effective stress range (MPa)</th>
<th>$V_s$ increase (%)</th>
<th>$V_p$ increase (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.41 to 0.96</td>
<td>18.4</td>
<td>18.0</td>
</tr>
<tr>
<td>0.96 to 1.52</td>
<td>10.5</td>
<td>9.2</td>
</tr>
<tr>
<td>1.52 to 2.07</td>
<td>7.5</td>
<td>7.1</td>
</tr>
<tr>
<td>2.07 to 2.62</td>
<td>5.8</td>
<td>5.2</td>
</tr>
<tr>
<td>2.62 to 3.17</td>
<td>4.1</td>
<td>4.8</td>
</tr>
<tr>
<td>3.17 to 3.72</td>
<td>4.3</td>
<td>4.4</td>
</tr>
<tr>
<td>3.72 to 4.27</td>
<td>3.1</td>
<td>3.7</td>
</tr>
</tbody>
</table>

### (c) Unconsolidated sand (without any sorting)

<table>
<thead>
<tr>
<th>Effective stress range (MPa)</th>
<th>$V_s$ increase (%)</th>
<th>$V_p$ increase (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.41 to 0.96</td>
<td>29.3</td>
<td>27.0</td>
</tr>
<tr>
<td>0.96 to 1.52</td>
<td>12.9</td>
<td>12.3</td>
</tr>
<tr>
<td>1.52 to 2.07</td>
<td>10.6</td>
<td>9.6</td>
</tr>
<tr>
<td>2.07 to 2.62</td>
<td>6.2</td>
<td>6.0</td>
</tr>
<tr>
<td>2.62 to 3.17</td>
<td>5.0</td>
<td>4.1</td>
</tr>
<tr>
<td>3.17 to 3.72</td>
<td>3.5</td>
<td>2.9</td>
</tr>
<tr>
<td>3.72 to 4.27</td>
<td>3.4</td>
<td>2.5</td>
</tr>
</tbody>
</table>

### (d) Well-cemented sandstone

<table>
<thead>
<tr>
<th>Effective stress range (MPa)</th>
<th>$V_s$ increase (%)</th>
<th>$V_p$ increase (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.41 to 0.96</td>
<td>4.0</td>
<td>7.5</td>
</tr>
<tr>
<td>0.96 to 1.52</td>
<td>2.2</td>
<td>3.4</td>
</tr>
<tr>
<td>1.52 to 2.07</td>
<td>1.1</td>
<td>1.8</td>
</tr>
<tr>
<td>2.07 to 2.62</td>
<td>0.3</td>
<td>0.8</td>
</tr>
<tr>
<td>2.62 to 3.17</td>
<td>0.3</td>
<td>0.5</td>
</tr>
<tr>
<td>3.17 to 3.72</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>3.72 to 4.27</td>
<td>0.2</td>
<td>0.3</td>
</tr>
</tbody>
</table>

Table 2.4: Results of the stress-sensitivity tests (dry samples).
2.6.1.3: Hysteresis

Sample 1.1 (loosely consolidated sandstone) was initially tested with increasing effective stress up to 48.2MPa ("loading 1"). Identical measurements were then performed and elastic wave velocities calculated when successively decreasing the effective stress ("unloading 1") and increasing the effective stress ("loading 2"). The purpose of this succession of loading and unloading was to detect any possible hysteresis of evolution of P- or S-wave velocities with effective stress. Results are plotted on Figures 2.24 and 2.25. Small differences of elastic wave velocities with the type of the stress regime (loading or unloading) are noticed. However, these differences are situated within the estimated measurement error range. No hysteresis is therefore considered to influence the elastic wave velocities on the loosely consolidated samples.

A similar experiment was carried out on sample SU10 in order to check the possible presence of hysteresis on the unconsolidated sand. After loading up to 67.5MPa, elastic wave velocities were calculated when decreasing effective stress. Results are presented in Figures 2.26 and 2.27. These figures surprisingly highlight the absence of hysteresis effect on the unconsolidated sands, for both P- and S-wave velocities.

![Figure 2.24: P-wave velocity with effective stress (loosely consolidated sandstone). Loading and unloading.](image)
Figure 2.25: S-wave velocity with effective stress (loosely consolidated sandstone). Loading and unloading.

Figure 2.26: P-wave velocity with effective stress (unconsolidated sand). Loading and unloading.

Figure 2.27: S-wave velocity with effective stress (unconsolidated sand). Loading and unloading.
2.6.2: Petrophysical tests

2.6.2.1: Nomenclature of samples and procedure

Stress-sensitivity of both porosity and permeability was determined for the loosely consolidated sandstones (samples 1.1b and 1.2) and for the unconsolidated sands (samples SU3 and SU6). Sample SU3 corresponds to a well-sorted unconsolidated sand sample whereas sample SU6 is an unconsolidated sand sample without any sorting. Maximum effective stress value applied on samples 1.1b, SU3 and SU6 was 48.2MPa, whereas it was 37.2MPa for sample 1.2. Permeability in the case of sample 1.2 could however not be recorded for effective stress larger than 20.7MPa. This petrophysical test was not performed on the well-cemented sandstone sample. This was due to the low absolute permeability of the well-cemented sandstone (5mD at ambient condition), preventing dead oil to flow through the samples and therefore preventing the test to be carried out. Porosity and permeability of the well-cemented sandstone were considered to be insensitive to effective stress levels.

2.6.2.2: Porosity and permeability relationships with effective stress

Figures 2.28 and 2.29 respectively present porosity and permeability evolution with effective stress measured on the loosely consolidated sandstones and on the unconsolidated sands. Both porosity and permeability decrease when effective stress is increased, and larger decreases are noticed for the unconsolidated samples. Porosity and permeability are clearly functions of the degree of consolidation of the sample. Moreover, porosity and permeability of the unconsolidated sands, in contrast to the elastic wave velocity, depends on the grain sorting. This is highlighted by the plots of permeability versus porosity measured on the unconsolidated sands for various effective...
stress values, allowing distinction of the sands upon their sorting (Figure 2.30). Table 2.5 summarises the main results concerning the porosity and permeability stress-sensitivity for the loosely consolidated sandstones and the unconsolidated sands.

**Figure 2.28:** Porosity versus effective stress (loosely consolidated sandstones and unconsolidated sands).

**Figure 2.29:** Permeability versus effective stress (loosely consolidated sandstones and unconsolidated sands).
Figure 2.30: Porosity versus permeability for varying effective stress levels (loosely consolidated sandstones and unconsolidated sands).

(a) Loosely consolidated sandstone

<table>
<thead>
<tr>
<th>Effective stress range (MPa)</th>
<th>Porosity decrease (%)</th>
<th>Permeability decrease (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>04.1 to 09.6</td>
<td>1.8</td>
<td>9.3</td>
</tr>
<tr>
<td>09.6 to 15.2</td>
<td>0.9</td>
<td>9.2</td>
</tr>
<tr>
<td>15.2 to 20.7</td>
<td>0.5</td>
<td>9.5</td>
</tr>
<tr>
<td>20.7 to 25.2</td>
<td>0.4</td>
<td>6.3</td>
</tr>
<tr>
<td>26.2 to 31.7</td>
<td>0.3</td>
<td>4.3</td>
</tr>
<tr>
<td>31.7 to 37.2</td>
<td>0.3</td>
<td>3.1</td>
</tr>
<tr>
<td>37.2 to 42.7</td>
<td>0.3</td>
<td>1.8</td>
</tr>
</tbody>
</table>

(b) Unconsolidated sand (with sorting)

<table>
<thead>
<tr>
<th>Effective stress range (MPa)</th>
<th>Porosity decrease (%)</th>
<th>Permeability decrease (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>04.1 to 09.6</td>
<td>2.1</td>
<td>3.0</td>
</tr>
<tr>
<td>09.6 to 15.2</td>
<td>1.8</td>
<td>2.7</td>
</tr>
<tr>
<td>15.2 to 20.7</td>
<td>1.6</td>
<td>2.2</td>
</tr>
<tr>
<td>20.7 to 25.2</td>
<td>1.5</td>
<td>2.5</td>
</tr>
<tr>
<td>26.2 to 31.7</td>
<td>1.3</td>
<td>2.3</td>
</tr>
<tr>
<td>31.7 to 37.2</td>
<td>1.1</td>
<td>3.5</td>
</tr>
<tr>
<td>37.2 to 42.7</td>
<td>1.0</td>
<td>4.4</td>
</tr>
</tbody>
</table>

(c) Unconsolidated sand (without any sorting)

<table>
<thead>
<tr>
<th>Effective stress range (MPa)</th>
<th>Porosity decrease (%)</th>
<th>Permeability decrease (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>04.1 to 09.6</td>
<td>3.6</td>
<td>6.5</td>
</tr>
<tr>
<td>09.6 to 15.2</td>
<td>2.6</td>
<td>6.3</td>
</tr>
<tr>
<td>15.2 to 20.7</td>
<td>2.0</td>
<td>5.7</td>
</tr>
<tr>
<td>20.7 to 25.2</td>
<td>1.6</td>
<td>7.9</td>
</tr>
<tr>
<td>26.2 to 31.7</td>
<td>1.3</td>
<td>6.4</td>
</tr>
<tr>
<td>31.7 to 37.2</td>
<td>1.2</td>
<td>8.6</td>
</tr>
<tr>
<td>37.2 to 42.7</td>
<td>1.3</td>
<td>8.3</td>
</tr>
</tbody>
</table>

Table 2.5: Results of the petrophysical tests.
2.6.2.3: Grain crush for unconsolidated sands

Measurement of porosity evolution with effective stress, performed on the unconsolidated material, allowed estimating if any grain crush occurred during the tests. For granular materials, a rough decrease of porosity with increase of effective stress can indeed be interpreted as a consequence of grain crush (Yin and Dvorkin, 1994). Such decrease was not noticed on experiments performed on the unconsolidated sands (with or without any sorting upon the grain size distribution) for effective stress up to 48.2MPa (Figure 2.28). It is therefore unlikely that major grain crush happened during the experiments.

This is confirmed by the results of the particle size distribution using the particle size analyser ("Mastersizer" laser light scattering-based), carried out on the unconsolidated sand samples before and after the dry frame tests. Figures 2.31 and 2.32 respectively present the grain size distribution of samples SU9 and SU10 before and after testing. No major difference is noticed. This leads to the conclusion that the grains forming the unconsolidated sands were not significantly altered by the experimental process. This may also explain why no elastic wave velocity hysteresis was noticed, as illustrated by Figures 2.26 and 2.27.
2.6.3: Pore fluid tests

2.6.3.1: Nomenclature of samples and procedure

As for the petrophysical tests, pore fluid tests were performed on the loosely consolidated sandstones and on the unconsolidated sands. They were not carried out on the well-cemented sandstone, due to its low permeability value. Table 2.6 summarises the experimental test procedure performed on the samples during this set of tests. Figures 2.33 to 2.43 highlight the main results showing the evolution of elastic wave velocities with fluid pressure and fluid saturation level changes.
Sample 1.1
Starting from:
dry sample
external stress: 20.7MPa
pore pressure: 0MPa
then
saturate with dead oil,
increase external stress to 48.2MPa
and pore pressure to 27.6MPa,
decrease pore pressure to 6.89MPa

Sample 1.1b
Starting from:
dead oil-saturated sample
external stress: 0MPa
pore pressure: 0MPa
then
increase external stress to 48.2MPa,
increase pore pressure to 44.1MPa

Sample 1.3
Starting from:
dry sample
external stress: 20.7MPa
pore pressure: 0MPa
then
saturate with dead oil,
increase external stress to 48.2MPa
and pore pressure to 27.6MPa,
decrease pore pressure to 0MPa

Sample 1.5
Starting from:
dry sample
external stress: 20.7MPa
pore pressure: 0MPa
then
saturate with brine,
increase external stress to 48.2MPa
and pore pressure to 27.6MPa,
inject dead oil

Sample 3.1
Starting from:
dry sample
external stress: 20.7MPa
pore pressure: 0MPa
then
saturate with brine,
increase external stress to 48.2MPa
and pore pressure to 27.6MPa,
inject dead oil,
inject methane

Sample 3.2
Starting from:
dry sample
external stress: 20.7MPa
pore pressure: 0MPa
then
saturate with brine,
increase external stress to 48.2MPa
and pore pressure to 27.6MPa,
inject dead oil,
inject brine

Table 2.6: Pore fluid tests. Experimental procedure.
2.6.3.2: Pore pressure effects

Figures 2.33 and 2.34 illustrate the similar evolution of the elastic wave velocities with effective stress when increasing the total stress and keeping the pore pressure constant on one hand, and when decreasing the pore pressure and keeping the total stress constant on the other hand (sample 1.1b). Discrepancies are however noticed on Figure 2.34 for the S-wave velocity at low effective stress levels. Without considering these discrepancies, the effects of pore pressure decrease (or increase) on wave velocities are considered to be identical to the effects of external stress increase (or decrease) on the loosely consolidated sandstones, when saturated with dead oil. This confirms the assumption of the Biot constant equals to 1, in the case of the loosely consolidated sandstones, as stated in Section 2.4.1.

![Graph](image)

**Figure 2.33:** P-wave velocity versus effective stress (sample 1.1b).
2.6.3.3: Pore fluid substitution effects

Figures 2.35 to 2.40 show the evolution of both P- and S-wave velocities with fluid saturation levels on sample 3.1 (loosely consolidated sandstone) when respectively injecting brine into the dry sample, then injecting dead oil, and then injecting methane. It emerges from these figures that larger P-wave velocity changes occur when methane is injected into the oil-saturated sample (2.4% changes) than when oil is injected into the brine-saturated sample (1.1% changes). This is due to the higher compressibility of the gas, comparatively to these of the brine and the dead oil. This therefore leads to larger fluid contrasts of P-wave velocities when gas is injected into the samples, despite the much smaller density of the gas (Table 2.2). Small contrasts between brine and dead oil properties explains the low variations of elastic wave velocities when dead oil is injected into a brine-saturated loosely consolidated sandstone. Recorded waveforms after each of these fluid injections through sample 3.1 are shown on Figures 2.41 and 2.42, and highlight the impact that fluids have on both wave travel-time and attenuation.
Figure 2.35: P-wave velocity versus brine saturation (sample 3.1). Brine injection into the dry sample at 20.7MPa effective stress.

Figure 2.36: S-wave velocity versus brine saturation (sample 3.1). Brine injection into the dry sample at 20.7MPa effective stress.

Figure 2.37: P-wave velocity versus oil saturation (sample 3.1). Oil injection into the brine-saturated sample at 20.7MPa effective stress.
Figure 2.38: S-wave velocity versus oil saturation (sample 3.1). Oil injection into the brine-saturated sample at 20.7MPa effective stress.

Figure 2.39: P-wave velocity versus gas saturation (sample 3.1). Gas injection into the oil-saturated sample (after oil injection) at 20.7MPa effective stress.

Figure 2.40: S-wave velocity versus gas saturation (sample 3.1). Oil injection into the oil-saturated sample (after oil injection) at 20.7MPa effective stress.
Figure 2.41: P-waveforms at 20.7MPa effective stress for varying pore fluid type (sample 3.1).

Figure 2.42: S-waveforms at 20.7MPa effective stress for varying pore fluid type (sample 3.1).

Figure 2.43 presents the evolution of the P-wave velocity with dead oil injection through the brine-saturated sample SU1 (unconsolidated sand without any sorting upon the grain size distribution). Larger P-wave velocity changes occur when brine is substituted by dead oil through the unconsolidated sand (5.8% changes) than through the loosely consolidated sandstone (1.1% changes). This is explained by the fact that, in the case of the unconsolidated sands, porosity is larger and rock frame elastic moduli are smaller. Table 2.7 summarises the main results concerning the pore fluid
substitution effects for the loosely consolidated sandstones and the unconsolidated sands. It highlights the large changes of $V_p/V_s$ ratio, especially when brine is injected into a dry sample or when gas is injected into a fluid-saturated sample (loosely consolidated). It also shows the huge increase of P-wave velocity (more than 88%) when brine is injected into the dry unconsolidated sand.

![Graph](image)

**Figure 2.43:** P-wave velocity versus oil saturation (sample SU1). Oil injection into the brine-saturated sample at 20.7MPa effective stress.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Step</th>
<th>Fluid substitution</th>
<th>$V_p$ change (%)</th>
<th>$V_s$ change (%)</th>
<th>$V_p/V_s$ change (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1</td>
<td>1</td>
<td>dry to 100% oil</td>
<td>4.7</td>
<td>-3.9</td>
<td>8.9</td>
</tr>
<tr>
<td>1.5</td>
<td>1</td>
<td>dry to 100% brine</td>
<td>7.3</td>
<td>-3.2</td>
<td>10.8</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>oil injection</td>
<td>-1.2</td>
<td>0.2</td>
<td>-1.5</td>
</tr>
<tr>
<td>3.1</td>
<td>1</td>
<td>dry to 100% brine</td>
<td>5.6</td>
<td>-3.2</td>
<td>9.1</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>oil injection</td>
<td>-1.1</td>
<td>0.1</td>
<td>-1.2</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>gas injection</td>
<td>-2.3</td>
<td>1.2</td>
<td>-3.5</td>
</tr>
<tr>
<td>3.2</td>
<td>1</td>
<td>dry to 100% brine</td>
<td>5.3</td>
<td>-3.9</td>
<td>9.6</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>oil injection</td>
<td>-2.1</td>
<td>0.4</td>
<td>-2.4</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>brine injection</td>
<td>1.1</td>
<td>-0.2</td>
<td>1.3</td>
</tr>
<tr>
<td>SU1</td>
<td>1</td>
<td>dry to 100% brine</td>
<td>88.5</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>oil injection</td>
<td>-5.8</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

**Table 2.7:** Results of the pore fluid substitution tests at constant effective stress level (20.7MPa). The external stress level is maintained at 48.2MPa, the pore pressure is set at 27.6MPa.
Core sample representativeness of reservoir properties

Core samples are an important source of input data for the prediction of reservoir petrophysical and elastic properties, as illustrated by this present chapter. They therefore play a critical role in the process of time-lapse feasibility studies. However, their reservoir representativeness might be questionable.

Firstly, as both core sample and reservoir scales are different, properties measured on small cores may not describe accurately those of large heterogeneous reservoirs. A way to get round this problem would be to acquire data on a large number of different cores from the same reservoir and then to statistically combine the results.

A second cause of misrepresentativeness is related to the core damage effects. Indeed, possible core damage due to stress release during drilling might be permanent in some cases (Holt et al., 1994). This permanent core damage may lead to an overestimation of the stress-sensitivity and to an underestimation of the stiffness of the sample compared to those of the in situ rock (Fjaer and Holt, 1999; Nes et al., 2000). Time-lapse effects might thus be overestimated.

Other sources of discrepancies between laboratory and seismic data include the differences of wave frequency content (much smaller for seismic data), the possible differences of temperature, or stress state conditions. However, such measurements on core samples, integrated with well log data, give an indication of the possible effects of saturation and pressure changes on time-lapse seismic (Landrø et al., 1999).
2.8: Conclusions

Three different types of tests have been performed in the laboratory on three clastic rocks extracted from the same sandstone type: loosely consolidated, well-cemented sandstones, and unconsolidated sands. Elastic wave velocities, porosity and permeability have been measured at different effective stress, fluid content and saturation levels. Results show that these parameters are stress-sensitive, and that elastic wave velocities are dependent on the fluid saturation levels within the sample pores. Stress-sensitivity greatly depends on the degree of consolidation and on the degree of cementation of the samples, the less consolidated and cemented the samples, the more stress-sensitive the samples are. This rock physics feasibility study also shows that the unconsolidated sands are the samples the most sensitive to fluid effects. Loosely consolidated sandstones are also sensitive to fluid effects, their degree of sensitivity varying with the effective stress levels, whereas the well-cemented sandstone is stiffer and consequently less sensitive to fluid effects.
Chapter 3: Analysis and Interpretation of the Rock Physics Experiments

This chapter, after reviewing some principal aspects of the theory of elasticity in porous medium, focuses on two main issues:

i. the comparison of the measurements performed in the laboratory on the Lochaline samples with existing rock physics theory predictions (fluid substitution and granular medium theory);

ii. the estimation and quantification of the effects of consolidation and cementation on the elastic wave velocities of dry samples at various levels of effective stress.

3.1: Theory of elasticity in porous medium

Rock physics and seismic measurements are governed by the law of wave propagation in elastic porous medium. The wave propagation equation is derived by combining Hooke's law with the equation of equilibrium (Bourbié et al., 1986). It directly relates the elastic wave velocities to the elastic parameters of the rock.

3.1.1: Linearly elastic material

For a given material, any particle (M) of this material met by a wave, experiences the effect of two types of disturbance: stress and strain. Stress and strain are represented by two tensors of second order with nine components: the stress tensor ($\sigma_{ij}$) and the strain tensor ($\varepsilon_{ij}$). A material is linearly elastic if, for any given particle (M) of this material
subjected to small deformations, each of the nine components of the stress tensor \((\sigma_{ij})\) is linearly linked to the nine components of the related strain tensor \((\varepsilon_{ij})\). For such a linearly elastic material, Hooke’s law linearly relates the stress tensor \((\sigma_{ij})\) to the strain tensor \((\varepsilon_{ij})\) by a fourth order tensor with eighty-one components, the stiffness tensor \((C_{ijkl})\), as described by Mavko et al. (1998):

\[
\sigma_{ij} = C_{ijkl} \varepsilon_{kl}.
\]  (3.1)

The eighty-one components of the stiffness tensor describe completely the elasticity of the material. Given symmetry considerations, these eighty-one components are not completely independent and the stiffness tensor is actually made of twenty-one independent components (Bourbié et al., 1986).

### 3.1.2: Homogeneous and isotropic material

Homogeneity and isotropy of a material are defined as follows. A material is homogeneous (the opposite of heterogeneous) if its properties, measured in a given direction, are independent of the location of measurement. A material is isotropic (the opposite of anisotropic) if its properties, measured in a given location, are independent of the direction of measurement (Winterstein, 1990). In a homogeneous and isotropic material, the stiffness tensor \((C_{ijkl})\) is represented by a set of two parameters: \(\lambda\) and \(\mu\), the Lamé constants (Bourbié et al., 1986), or alternatively \(K\) and \(\mu\), the elastic moduli of the material. \(\mu\) is called the shear modulus of the material, and \(K\), the bulk modulus of the material, is defined as follows:

\[
K = \lambda + \frac{2}{3} \mu.
\]  (3.2)
The bulk modulus \((K)\) describes the reluctance of the material to change volume, whereas the shear modulus \((\mu)\) describes the reluctance of the material to change shape (Anstey, 1991). In the case of such a linearly elastic, isotropic and homogeneous material, Hooke’s law is expressed as follows (Mavko et al., 1998):

\[
\sigma_{ij} = \lambda \delta_{ij} \varepsilon_{\alpha\alpha} + 2\mu \varepsilon_{ij} = \left( K - \frac{2}{3} \mu \right) \delta_{ij} \varepsilon_{\alpha\alpha} + 2\mu \varepsilon_{ij},
\]

(3.3)

with \(\delta\) the Kronecker symbol \((\delta_{ij} = 0 \text{ if } i \neq j, \delta_{ij} = 1 \text{ if } i = j)\).

The equation of equilibrium (Equation 3.4) is independently expressed by relating the stress tensor first derivative \((\sigma_{,ij})\) to the density \((\rho)\) of the material and to the vector displacement second derivative \(\left( \frac{\delta^2 u}{\delta t^2} \right)\) of the particle \((M)\), as presented in Bourbié et al. (1986):

\[
\sigma_{,ij} = \rho \frac{\delta^2 u}{\delta t^2}.
\]

(3.4)

In the case of a linearly elastic isotropic and homogeneous material, combining Equation 3.3 with Equation 3.4 into Equation 3.5 finally allows derivation of both the compressional and the shear wave velocities \((V_p\) and \(V_s\)):

\[
V_p = \sqrt{\frac{\lambda + 2\mu}{\rho}} = \sqrt{\frac{K + \frac{4}{3} \mu}{\rho}},
\]

(3.5a)

\[
V_s = \sqrt{\frac{\mu}{\rho}}.
\]

(3.5b)

Equation 3.5 highlights the fact that elastic wave velocities are sensitive to the density and to the elasticity of the material.

As stated in Section 2.4.1, all the experiments carried out in this study were performed on samples under hydrostatic loading (i.e. the three major external stresses were equal).
Moreover, Lochaline samples (loosely consolidated, well-cemented sandstones, and unconsolidated sands) were, at the laboratory scale, homogeneous and isotropic, as stated in Section 2.1. Moreover, in the scope of the laboratory experiments, the strains generated by the high frequency wave were within the hypothesis of small deformations, i.e. \( \varepsilon < 10^{-6} \) (Bourbié et al., 1986). Therefore, determining the elastic moduli (\( K \) and \( \mu \)) from the elastic wave velocities (\( V_p \) and \( V_s \)) allow the full description of the elastic characteristics of the tested samples, as the assumption of a linearly elastic isotropic and homogeneous material is verified for this set of experiments.

### 3.2: Fluid substitution effects on elastic wave velocities

#### 3.2.1: Gassmann's relations

Gassmann's relations are commonly used to derive the bulk modulus (\( K_r \)) and the shear modulus (\( \mu_r \)) of a fluid-saturated porous rock (Gassmann, 1951). Gassmann's equations allow quantifying the changes of elastic wave velocities due to fluid substitution in the rock pore volume (Mavko et al., 1998). They are based on several assumptions, enumerated as follows:

- the rock is linearly elastic, isotropic and homogeneous;
- the rock-fluid system is closed;
- the pores of the rock are interconnected;
- the pore pressure is equilibrated within the pore space;
- the pores are filled with a frictionless liquid;
- the fluid does not interact with the solid in a way that would soften or harden the rock frame.
Gassmann's equations are free of assumptions concerning the pore network geometry. The parameters required to use Gassmann's relations are the rock porosity ($\phi$) in fraction, the bulk and shear moduli of the dry frame ($K_d$ and $\mu_d$), the bulk modulus of the mineral making up the rock ($K_m$), and the bulk modulus of the pore fluid filling the rock ($K_r$). Gassmann's relations are presented as follows (Wang, 2000):

\[
K_s = K_d + \frac{(1 - \frac{K_d}{K_m})^2}{\phi + \frac{1 - \phi}{K_r} - \frac{K_d}{K_m^2}},
\]

(3.6a)

\[
\mu_s = \mu_d.
\]

(3.6b)

P- and S-wave velocities are then derived using the elastic moduli and the density of the fluid-saturated samples (Equation 3.5). In the case of quartz mineral, the value of the bulk modulus of the mineral ($K_m$) is 38GPa, and the value of the density of the mineral ($\rho_m$) is 2.65g/cm$^3$ (Carmichael, 1982). The density of the dry sample ($\rho_d$) and the density of the fluid-saturated sample ($\rho_s$) are determined by the density of the mineral making up the rock ($\rho_m$), the porosity ($\phi$), and the density of the fluid ($\rho_f$), as stated by Equation 3.7:

\[
\rho_d = \rho_m (1 - \phi).
\]

(3.7a)

\[
\rho_s = \rho_m (1 - \phi) + \rho_f \phi.
\]

(3.7b)

Equation 3.6b highlights that no shear modulus changes with saturation are predicted by Gassmann's theory. Moreover, Equation 3.6 also shows, as it does not contain any explicit effective stress term, that Gassmann's equations have to be computed independently at various effective stress levels to take into account the effective stress-sensitivity of the rock frame elasticity.
3.2.2: Rock frame elastic moduli

Equation 3.6 highlights the importance of the rock frame parameters for quantifying the elastic wave velocity changes with fluid substitution. The larger the dry frame bulk modulus ($K_d$), the smaller the changes in the pore volume term, and therefore the smaller the elastic wave velocity changes due to fluid substitution. Elastic moduli of the dry frame depend on intrinsic parameters, such as pore geometry, grain size distribution, grain sorting, grain angularity, grain roughness, grain-to-grain contact area or clay content. As no theory exists to exhaustively link all these petrophysical parameters to the elastic moduli of the rock and to their evolution with effective stress (Nes et al., 2000), empirical methods are usually performed to determine the elastic moduli of the dry frame ($K_d$ and $\mu_d$). Results are then incorporated into Gassmann's relations to predict the fluid substitution effects.

In the case of this study, rock physics measurements were carried out on dry rock samples for varying effective stress levels (Section 2.4.2). By combining the dry frame elastic wave velocities, and the porosity computed on sister plugs, elastic moduli of the dry frame ($K_d$ and $\mu_d$) were derived for varying effective stress levels by Equation 3.8 to be used as input into Gassmann's equations:

\[
K_d = \rho_d \left( V_p^2 - \frac{4}{3} V_s^2 \right) = \rho_m (1-\phi) \left( V_p^2 - \frac{4}{3} V_s^2 \right), \tag{3.8a}
\]

\[
\mu_d = \rho_d V_s^2 = \rho_m (1-\phi) V_s^2. \tag{3.8b}
\]

Gassmann's predicted elastic wave velocities could be then compared with the elastic wave velocities calculated from the measurements performed on the fluid-saturated samples.
3.2.3: Wave frequency limit and velocity dispersion

3.2.3.1: Wave frequency limit

Gassmann's relations perform best at low wave frequencies (Mavko et al., 1998). They are therefore more likely to be valid at seismic wave frequencies (30-100Hz) but may not be as accurate at well log sonic wave frequencies (1-10kHz) and especially at laboratory ultrasonic wave frequencies (0.1-1MHz). This is related to the fact that waves are dispersive in fluid-saturated medium (Winkler, 1985).

3.2.3.2: Velocity dispersion on dry samples

Velocity dispersion effects, which are inversely proportional to the pore network connectivity and thus to the permeability of the rock (Mavko et al., 1998), can lead to an overestimate of ultrasonic wave velocities compared to seismic wave velocities (Wang, 2000).

Three major independent effects, which may superpose together, cause velocity dispersion at the sample scale (Mavko, 1998). These three effects, which contribute to an increase of elastic wave velocities with the frequency of the wave, are:

- the Biot effect;
- the squirt flow effect;
- the heterogeneous saturation effect.

The Biot effect is detailed by Biot theory (Biot, 1956a; 1956b). Biot describes the existence of viscous and inertial forces between the fluid and the solid for high wave frequencies. These effects lead to a differential motion between the fluid and the solid,
and to a decrease of mass in the global motion. This creates an increase of elastic wave velocities with the frequency of the wave (Bourbié et al., 1986).

The squirt flow effect is described by Dvorkin et al. (1994a; 1995). It occurs when the wave frequency is high enough that pore pressure is not equilibrated within the microscopic scale pore space when a fluid-saturated sample is stressed by a passing wave. This leads to a stiffening of the compliant pores and therefore to an increase of the elastic wave velocities. As compliant pores, such as microcracks (intra-granular cracks), or grain-to-grain connective pores, close with the increase of effective stress during experiments, the squirt flow effect is more pronounced at low effective stress levels than at high effective stress levels (Mavko and Jizba, 1994). The heterogeneous saturation effect is described in Section 3.2.4.3.2.

For dry rocks, velocity dispersion rock is often negligible (Winkler, 1983). Therefore, elastic wave velocities actually measured at high wave frequency in the laboratory on dry samples would lead to similar results that if they were measured on the same samples at low wave frequency. It is therefore correct to use as input into Gassmann's relations, theoretically valid for low wave frequencies, the elastic wave velocities calculated on dry samples in the laboratory at ultrasonic wave frequencies.

3.2.4: Fluid substitution theory predictions compared with laboratory experiments

To evaluate Gassmann's fluid substitution relations on the Lochaline samples at ultrasonic wave frequencies (loosely consolidated sandstones and unconsolidated sands), P- and S-wave velocities were measured in the laboratory on samples saturated with various fluids (brine, dead oil, gas). Results could then be compared with Gassmann's elastic wave velocity predictions computed by combining the elastic
moduli of the dry samples to the properties of the fluids. Two different cases are studied, depending if the pore space is filled by:

- one single fluid;
- a mixture of fluids.

3.2.4.1: Fluid properties

Fluids used during the laboratory experiments (except the dry frame tests for which no fluid was involved) were brine (salinity of 50,000 ppm and viscosity of 1cp), dead oil (density of 0.867g/cm³ and viscosity of 28cp), and methane (specific gravity G of 0.6). Concerning the oil, the evolutions of the bulk modulus and density as a function of pressure were given by the oil manufacturer. Density and bulk modulus of brine and gas were computed for various pressures using Batzle and Wang’s equations (Batzle and Wang, 1992). Fluid properties, at ambient temperature (16°C) are presented in Figures 3.1 and 3.2.

![Figure 3.1: Density versus pressure at ambient temperature (fluids used for laboratory experiments).](image-url)
3.2.4.2: Single fluid

Two parameters related to the pore fluids intervene for computing the elastic wave velocities using Gassmann's relations: the density of the fluid \( \rho_f \) and the bulk modulus of the fluid \( K_f \). When the pore network of a rock is filled by one single fluid, determination of \( \rho_f \) and \( K_f \) is direct, as these parameters correspond to the parameters of the unique fluid. Density and bulk modulus of the fluids used in the laboratory for the experiments are presented in Section 3.2.4.1.

Figures 3.3 and 3.4 show plots of P- and S-wave velocities measured on a loosely consolidated sample saturated with dead oil compared with elastic wave velocities predicted by Gassmann's relations for various effective stress levels. Results show that, for the loosely consolidated sandstones, elastic wave velocities measured on the fluid-saturated samples are very close to those predicted by Gassmann's relations. As predicted by the theory, small differences exist, especially at low effective stress levels, but they are within the range of the estimated wave velocity measurement errors. Gassmann's equations therefore perform well on this clean sandstone, and can be applied to quantify the effect of fluids on elastic wave velocities measured in the
laboratory. This good fit, despite the large frequencies of the waves used during the experiments, can be explained by the high permeability of the tested samples, which limits velocity dispersion, as stated in Section 3.2.3.2.

Figure 3.3: P-wave velocity versus effective stress. Comparison with Gassmann's prediction (loosely consolidated sandstone).

Figure 3.4: S-wave velocity versus effective stress. Comparison with Gassmann's prediction (loosely consolidated sandstone).
Concerning the unconsolidated sands, Figures 3.5 and 3.6 show plots of P-wave velocities measured on core samples saturated with dead oil (with and without any sorting upon the grain size distribution) compared with P-wave velocities predicted by Gassmann’s relations, at various levels of effective stress. The fit is relatively good, but not as good as for the loosely consolidated sandstones. This is likely to be related to the largest absolute uncertainty on the sample property measurements performed on the unconsolidated material compared with those carried out on the consolidated material. Moreover, due to poor signal quality, a clear S-wave first arrival time could not be detected on the data measured during the experiments performed on the fluid-saturated unconsolidated sands. This signifies that S-wave travel-times could not be measured on the fluid-saturated sands. However, as Gassmann’s theory predicts no changes of shear modulus with fluids, saturated unconsolidated sand S-wave can be predicted at various levels of effective stress, from the measurements performed on the dry samples, given the density of the fluid.
Figure 3.5: P-wave velocity versus effective stress. Comparison with Gassmann's prediction (unconsolidated sand without any sorting upon the grain size distribution).

Figure 3.6: P-wave velocity versus effective stress. Comparison with Gassmann's prediction (unconsolidated sand with sorting upon the grain size distribution).
3.2.4.3: Fluid mixture at the sample scale

Reservoir rocks are filled by a mixture of different fluids, and not by one single fluid. Quantifying fluid saturation level of each of the fluids filling the pores of a reservoir rock is of a major importance for rock physics and seismic reservoir monitoring studies. This requires an understanding of the fluid saturation distribution within the rock pores, homogeneous or heterogeneous, as fluid saturation distribution can greatly affect the bulk modulus of the rock (Knight and Nur, 1987; Knight et al., 1998). This section focuses on this issue at the microscopic scale (laboratory experiments on core samples) whereas Section 5.4 focuses on the same issue at the macroscopic scale (seismic experiments).

3.2.4.3.1: Density of a fluid mixture

Considering the most general case, with a fluid mixture made of:

- water (saturation ($S_w$), density ($\rho_w$), bulk modulus ($K_w$));
- oil (saturation ($S_o$), density ($\rho_o$), bulk modulus ($K_o$));
- gas (saturation ($S_g$), density ($\rho_g$), bulk modulus ($K_g$));

the density of the fluid mixture ($\rho_f$) is calculated as follows:

$$\rho_f = \sum_i S_i \rho_i = S_w \rho_w + S_o \rho_o + S_g \rho_g,$$

(3.9)
3.2.3.2: Bulk modulus of a fluid mixture and critical diffusion length

Determination of the bulk modulus of the fluid mixture (Kr) is not as direct as it is for the fluid mixture density. According to Domenico (1977), Kr can be described as an effective medium property, bounded by two models:

- the iso-stress model;
- the iso-strain model.

The iso-stress model (or Reuss lower bound) is given by the harmonic average, whereas the iso-strain model (or Voigt upper bound) is given by the arithmetic average. These two bounds, Reuss lower and Voigt upper bounds, in the case of the bulk modulus of a fluid mixture (Kr), are respectively computed as follows (Mavko and Mukerji, 1998):

\[
K_r = \frac{1}{\sum_i \frac{S_i}{K_i}} = \frac{1}{\frac{S_{w}}{K_{w}} + \frac{S_{o}}{K_{o}} + \frac{S_{g}}{K_{g}}},
\]

and

\[
K_r = \sum_i S_i K_i = S_{w} K_{w} + S_{o} K_{o} + S_{g} K_{g}.
\]

Voigt upper bound (iso-strain average) always leads to a higher (or identical) value than Reuss lower bound (iso-stress average). The most accurate bound to approximate the bulk modulus of a fluid mixture depends on the critical diffusion length (Lc). Lc is defined given two parameters (Mavko and Mukerji, 1998): the hydraulic diffusivity (D) and the central frequency of the wave (f). D is defined as follows:

\[
D = k \frac{K_r}{\eta_r},
\]

with k the absolute permeability (m², with 1Darcy =0.986923.10⁻¹²m²), and Kr and ηr, respectively the bulk modulus (Pa) and the viscosity (Pa.s, with 1cp=10⁻³Pa.s) of the most viscous fluid phase.
Le is then defined as follows:

\[ L_e = \sqrt{\frac{D}{f}}. \]  

(3.13)

\( L_e \), which depends on both the hydraulic diffusivity and the frequency of the wave, directly controls the effect of the distribution of a fluid mixture on its bulk modulus and therefore on the P-wave velocity of a fluid-saturated rock.

In reservoir rocks, fluids do not have the same bulk modulus. For example, gas or live oil have smaller bulk modulus (larger compressibility) than brine; live oil with a large solution gas-oil ratio tends to have smaller bulk modulus than live oil with a small solution gas-oil ratio or dead oil. Therefore, when wave goes through rocks bearing several types of fluids, the wave-induced increment of pore pressure depends directly on the saturation distribution of the fluids within the rock pores. If in the pore space, fluid saturation heterogeneities are smaller than \( L_e \), then the wave-induced pore pressure has enough time to relax during half a wave time period (Mavko et al., 1998). Pore pressure is therefore equilibrated within the pore space, and the iso-stress model (Reuss lower bound) is likely to describe the bulk modulus of the fluid mixture. This is the case of a uniform (homogeneous) fluid saturation distribution. As large values of \( L_e \) are associated with low values of wave frequencies (Equation 3.13), pore pressure equilibrium is more likely to occur at low wave frequency values, such as seismic wave frequencies.

On the other hand, if fluid saturation heterogeneities are larger than \( L_e \), then the wave-induced pore pressure has no time to relax, and fluid pressure is not equilibrated within the pore space. This is most likely to occur at ultrasonic wave frequencies used for laboratory experiments for which \( L_e \) tends to be small, in the range of 0.1-1cm (Mavko and Mukerji, 1998). In this heterogeneous saturation distribution configuration (patchy
saturation), the iso-stress model is no longer valid to describe the bulk modulus of a fluid mixture and therefore can not be used as input into Gassmann’s equations (Mavko et al., 1998). In such a case, the bulk modulus of the fluid mixture can be approximated by the arithmetic average (Equation 3.11).

As these two averages give two extreme bounds, the real bulk modulus value for a fluid mixture may lie between these two bounds. Therefore, empirical models may be used to compute the bulk modulus of such a fluid mixture. For example, Brie et al. (1995) have derived an empirical law modelling the bulk modulus of a brine-gas mixture for intermediate fluid saturation distribution cases:

\[ K_f = (K_w - K_g)S_w^e + K_g, \]  
(3.14)
e being an adjustable parameter larger than 1.

Comparisons of the bulk modulus calculated using the harmonic and the arithmetic averages, and Brie’s law are plotted in the case of a brine-gas mixture at 27.6MPa on Figure 3.7. This figure illustrates that Brie’s law is identical to Voigt upper bound for \( e=1 \), whereas it gets closer to Reuss lower bound with increasing values of \( e \).

Figure 3.7: Bulk modulus of a mixture of fluids (brine and methane) at ambient condition. Comparisons of Brie’s law with Reuss and Voigt bounds.
3.2.4.3.3: Imbibition and Drainage

P-wave velocity of a rock filled by several fluids depends on the microscopic fluid distribution within the pore space, as discussed in Section 3.2.4.3.2. At the laboratory scale, the microscopic fluid distribution is experimentally governed by the technique used to inject fluids into the sample (Cadoret, 1993).

Two types of injection techniques exist: imbibition and drainage. Their definition is related to the concept of rock wettability. Wettability describes the relative adhesion of two immiscible fluids to a solid surface; it is a measure of the preferential tendency of one of the two fluids to spread to the surface (Tiab and Donaldson, 1996). Imbibition is the process of displacing a fluid (f_1) by a fluid (f_2) in a f_2-wet system. Drainage is the process of displacing a fluid (f_2) by a fluid (f_1) in a f_2-wet system (Knight and Nolens-Hoeksema, 1990). In a water-oil system, rock can be either water-wet or oil-wet. The wetting fluid tends to occupy the smaller pores and to wet the major portion of the surface of the larger pores (Domenico, 1976; Van Dijke et al., 2000). On the other hand, if gas (or air) is part of the fluid mixture, it is never the wetting-fluid (Honarpour et al., 1986).

When imbibition process is used, then fluid phases tend to be mixed at the finest scale (smaller than L_e), and the iso-stress model (Reuss lower bound) is likely to describe the bulk modulus of a fluid mixture (Knight et al., 1998; Mavko et al., 1998). When drainage process is used, then fluid phases do not tend to be mixed at the finest scale, and a patchy fluid distribution model is more likely to represent the effective fluid bulk modulus (Knight and Nolens-Hoeksema, 1990; Cadoret, 1993; Knight et al., 1998; Mavko et al., 1998).
Endres and Knight (1989) have, moreover, theoretically investigated the impact that aspect ratio of pores represented as ellipsoids may have on fluid saturation distribution in the case of drainage (for example gas injection or drying process). Aspect ratio is defined as the ratio of the lengths of the pore semi-minor axis to that of the pore semi-major axis. Its value lies between 0 and 1. The larger the aspect ratio of the pores, the less compressible are the pores, and therefore the less sensitive to fluids. Endres and Knight (1989) have thus interestingly related P-wave velocity relationships as a function of fluid saturation to the aspect ratio of the pores of the samples, as the draining fluid has tendency to occupy the high aspect ratio pores. Laboratory experiments performed on three different samples with three different pore aspect ratio distributions have confirmed these predictions (Goertz and Knight, 1998).

3.2.4.3.4: Laboratory experiments

In this current study, fluid substitution was performed on the loosely consolidated sandstones and on the unconsolidated sands. According to Equations 3.12 and 3.13, values of the critical diffusion length ($L_e$) lies between 0.1cm and 0.2cm for both the loosely consolidated sandstones and the unconsolidated sands, for a wave frequency of 0.7MHz. P- and S-wave travel-times were measured, as a function of saturation levels, as described in Section 2.6.3.3. Effective stress was maintained at 20.7MPa during these experiments to prevent any pressure effects influencing the rock elasticity to be added to the fluid effects. As clean sandstones exhibit preferential water wetting tendencies (Tiab and Donaldson, 1996), Lochaline samples are water wet. Imbibition was performed by injecting brine into a dry sample. Drainage was performed by injecting dead oil into a brine-saturated sample, or methane into a dead oil-saturated sample. The bulk modulus of the fluid mixture was computed using both the harmonic average (Reuss lower bound) and the arithmetic average (Voigt upper bound) of the...
fluid properties, to be incorporated into Gassmann’s relations. P- and S-wave velocities were then compared to those predicted by Gassmann’s relations.

Results are presented in Figures 3.8 to 3.13 for sample 3.1 (loosely consolidated sandstone). A similar evolution to this modelled by the iso-stress average is noticed for P-wave velocities in the imbibition case, when brine is injected into the loosely consolidated sandstone (Figure 3.8). A similar evolution to this modelled by the iso-strain average is noticed for P-wave velocities in the drainage case, when gas is injected into the loosely consolidated sandstone (Figure 3.12). This confirms the theory described in Section 3.2.4.3.3. Moreover, in the drainage case, when dead oil is injected into the brine-saturated samples, Reuss lower bound and Voigt upper bound predictions are very close and can almost not be distinguished. This is explained by the similarity of the properties of dead oil and brine as illustrated by Figure 3.10.

These figures highlight the importance of understanding the type of saturation distribution within the pore space for quantifying fluid saturation levels in the case of a fluid mixture. Considering a fluid mixture, if the difference between the bulk modulus of the fluids forming this mixture appears to be small, both uniform and patchy saturation distributions lead to a similar trend of the bulk modulus of the fluid mixture with fluid saturation (Figure 3.10). However, if the contrast is large, which is the case when gas is involved in the system, both saturation distribution patterns can lead to different bulk modulus values (Figure 3.12), especially for soft and high porosity rocks. For an identical level of saturation, P-wave velocity values in the case of uniform saturation distribution can be much smaller than for the case of a heterogeneous fluid distribution. This is illustrated by Figure 3.12, in the case of injection of methane in the dead oil-saturated loosely consolidated sandstone. It shows that for a gas saturation level of 15%, there is indeed a difference of 5% between the P-wave velocity values
predicted by the Reuss lower bound (3588 m/s) and by the Voigt upper bound (3772 m/s). This difference can lead to misinterpretation when trying to quantify saturation changes due to production within the reservoir by time-lapse analysis. Moreover, Figures 3.9, 3.11 and 3.13 show that the experimental results confirm the hypothesis of Gassmann’s relations according to which the shear modulus of a rock is independent of its fluid content: S-wave velocity changes are mainly due to density changes, considering the measurement error ranges.

Finally, it must be noticed that fluid saturation values calculated during these fluid substitution tests were determined by volumetric estimations, from the value of the pore volume of the core sample. As these calculations did not take into account possible fluid breakthrough, the real saturation of the injected fluid within the pore space might have been overestimated. Moreover, connate water saturation has not been measured but only estimated from Honarpour et al. (1986). The importance of these fluid saturation distribution effects on P-wave velocity, studied in this section at the core sample scale, is investigated at the reservoir scale in Chapter 5.
Figure 3.8: P-wave velocity versus brine saturation (sample 3.1). Brine injection into the dry sample at 20.7MPa effective stress. Comparison with Gassmann's predictions.

Figure 3.9: S-wave velocity versus brine saturation (sample 3.1). Brine injection into the dry sample at 20.7MPa effective stress. Comparison with Gassmann's prediction.

Figure 3.10: P-wave velocity versus oil saturation (sample 3.1). Oil injection into the brine-saturated sample at 20.7MPa effective stress. Comparison with Gassmann's predictions.
Figure 3.11: S-wave velocity versus oil saturation (sample 3.1). Oil injection into the brine-saturated sample at 20.7MPa effective stress. Comparison with Gassmann’s prediction.

Figure 3.12: P-wave velocity versus gas saturation (sample 3.1). Gas injection into the oil-saturated sample at 20.7MPa effective stress. Comparison with Gassmann’s predictions.

Figure 3.13: S-wave velocity versus gas saturation (sample 3.1). Gas injection into the oil-saturated sample at 20.7MPa effective stress. Comparison with Gassmann’s prediction.
3.3: Granular medium theory for unconsolidated sands

Granular medium theory deals with a dry, random, spherical pack of identical grains. This section is focused on the comparison of the elastic wave velocities predicted by the granular medium theory with those measured on the Lochaline unconsolidated sands. Several models predict P- and S-wave velocities versus effective stress in the case of a hydrostatic external loading (Mindlin, 1949; Digby, 1981; Walton, 1987). These models are based on the grain contact theory, described, for example, in Wang and Nur (1988). Attention is focused on Walton model, presented as follows.

Both bulk and shear dynamic moduli are derived in Walton theory considering:

- the normal and tangential contact stiffness of a grain-to-grain contact;
- petrophysical micro-structural statistical information (grain-to-grain contact number average, grain-to-grain contact area, grain radius);
- the roughness of the grains (perfectly smooth or infinitely rough), and its effect on both the grain-to-grain friction and on the grain slip at the grain-to-grain contact area.

Walton model predictions of the elastic moduli of the granular material are derived as follows (Mavko et al., 1998):

\[ K = \frac{1}{6} \sqrt{\frac{3(1-\phi)^2 C^2 \sigma}{\pi^4 B^2}} , \]  
(3.15a)

\[ \mu = \frac{\alpha}{10} \sqrt{\frac{3(1-\phi)^2 C^2 \sigma}{\pi^4 B^2}} , \]  
(3.15b)

where \( \alpha = \frac{5B+A}{2B+A} \) for rough grains, or \( \alpha = 1 \) for smooth grains.
A and B are parameters depending on the mineral forming the grains, and are given by:

\[ A = \frac{1}{4\pi} \left( \frac{1}{\mu_m} - \frac{1}{\mu_m + \lambda_m} \right) = \frac{1}{4\pi} \left( \frac{1}{\mu_m} - \frac{3}{\mu_m + 3K_m} \right), \tag{3.16a} \]

\[ B = \frac{1}{4\pi} \left( \frac{1}{\mu_m + \lambda_m} \right) = \frac{1}{4\pi} \left( \frac{1}{\mu_m + \frac{3}{\mu_m + 3K_m}} \right), \tag{3.16b} \]

with \( \mu_m \) and \( \lambda_m \), the Lamé constants of the mineral (quartz for the Lochaline samples), and \( K_m \) the bulk modulus of the mineral. A and B are computed assuming values of the quartz bulk modulus \( K_m \) and of the quartz shear modulus \( \mu_m \) of respectively 38GPa and 44GPa (Carmichael, 1982). Equation 3.15 clearly highlights the elastic moduli dependence upon porosity \( \phi \), effective stress \( \sigma \), average number of grain contacts per grain or coordination number \( C \), grain elastic properties (A and B), and grain roughness \( \alpha \). It also shows that grain roughness does not have any effect on the bulk modulus but influences the shear modulus: samples made with the roughest grains have the largest shear modulus and the smallest Poisson’s ratio. This is explained by the fact that smooth grains are allowed to slip when effective stress is applied which contributes to reduce the shear modulus of a granular medium.

Figures 3.14 to 3.17 present both P- and S-wave velocity evolution with varying effective stress levels measured on the unconsolidated from Lochaline with those predicted by Walton model. Coordination number \( C \) is computed according to the relation between \( C \) and porosity \( \phi \), given by Mavko et al. (1998). \( C \) value is 8.8 for sample SU9 and 9.1 for sample SU10. These figures highlight the impact grain roughness has on elastic wave velocities: the rougher the grains, the higher the elastic wave velocities. They moreover show that P- and S-wave velocities measured on the unconsolidated sands with effective stress are close to those predicted by Walton.
Figure 3.14: P-wave velocity versus effective stress. Comparison with Walton's predictions (sample SU9).

Figure 3.15: S-wave velocity versus effective stress. Comparison with Walton's predictions (sample SU9).

Figure 3.16: P-wave velocity versus effective stress. Comparison with Walton's predictions (sample SU10).
However, none of Walton model predictions (lower or upper predictions) correctly fits the experimental data. Both porosity ($\phi$) and effective stress ($\sigma$) were monitored during experiments, but the coordination number (C) and the grain roughness ($\alpha$) were not. An attempt to calibrate Walton model to fit the experimental data is presented as follows. It is based on the estimations of parameters (C) and ($\alpha$) considering the two following assumptions:

- the roughness ($\alpha$) of the grains is neither completely smooth nor completely rough but can take an intermediate value;
- the coordination number (C) increases with effective stress ($\sigma$).

These model calibration assumptions are tested on the Lochaline unconsolidated sands. For both types of sands, a good fit is obtained (Figures 3.18 and 3.19) by introducing the following coordination number (C) versus effective stress ($\sigma$) law dependence:

$$C = C_0 + C_1 \sigma^{1/3},$$

(3.17)

where $C_0$ and $C_1$ are constant parameters.

**Figure 3.17**: S-wave velocity versus effective stress. Comparison with Walton's predictions (sample SU10).
Walton model after calibration becomes therefore as follows:

\[
K = \frac{1}{6} \frac{3(1 - \phi(P))^2(C_0 + C_1 \sigma^{1/3})^2 \sigma}{\pi^4 B^2}, \tag{3.18a}
\]

\[
\mu = \frac{1}{10} \frac{3(1 - \phi(P))^2(C_0 + C_1 \sigma^{1/3})^2 \sigma}{\pi^4 B^2}, \tag{3.18b}
\]

where \( \alpha_{\text{smooth}} = 1 \leq \alpha \leq \alpha_{\text{rough}} = \frac{5B + A}{2B + A} \).

This increase of coordination number (C) may be explained by grain slipping inducing a grain packing geometry rearrangement. C is actually more likely to represent a grain-to-grain contact area and not a grain-to-grain contact number. The grain roughness coefficient (\( \alpha \)) is directly linked to the Poisson’s ratio of the material.

The calibration of Walton model described above assumes that the samples are made of grains with a same coefficient \( \alpha \), implying that all grains possess an identical roughness. This is realistic in the case of the Lochaline samples due to their homogeneity. Another approach would consist in considering that the granular medium can be made of a mixture of grains with different roughness (Bachrach et al., 2000).

Independently, an identical relation to Equation 3.17, derived from a similar experiment but performed on a packing of identical spherical glass beads, has been published in the literature (Makse et al., 1999). This may confirm the validity of this type of empirical relationship for granular medium in a general case.

It must also be pointed out that absolute values of P-wave velocities are 4% larger in the case of sample SU9 (sorting upon the grain size distribution) than in the case of sample SU10 (no sorting upon the grain size distribution). This was not initially expected, and might be partially explained by the magnitude of the absolute error measurements carried out on the unconsolidated material (Section 2.5). However, the elastic wave
velocity evolution with effective stress is similar in both cases and the absolute values of the S-wave velocities are almost similar in these two cases.

Granular medium theory, despite its strong assumptions (identical and spherical grains) can therefore be calibrated to experimental measurements performed on unconsolidated sands. Predicting precisely the elastic wave velocities on granular material from the properties of the grains only, without any laboratory measurements for calibration, still remains a topic for further research yet.

![Graph showing P- and S-wave velocities versus effective stress.](image)

**Figure 3.18:** P- and S-wave velocities versus effective stress. Comparison with Walton's predictions after calibration (sample SU9).

![Graph showing P- and S-wave velocities versus effective stress.](image)

**Figure 3.19:** P- and S-wave velocities versus effective stress. Comparison with Walton's predictions after calibration (sample SU10).
3.4: Rock elasticity dependence on consolidation, cementation and porosity

Rock elasticity can vary within a narrow porosity range. For example, cementation degree can dramatically increase the stiffness of a rock without generating large porosity changes (Dvorkin and Nur, 1996; Packwood, 1997). This can have significant impact for time-lapse feasibility studies, as between two reservoir rocks with an identical porosity value, the better candidate for seismic reservoir monitoring would be the softer reservoir rock. Moreover, cementation is not the only factor generating variations of the stiffness of a rock, consolidation for example is another. The effects of consolidation, cementation and porosity on the elasticity of the Lochaline core samples are studied in this section.

3.4.1: Rock frame elastic moduli versus effective stress

As presented in Chapter 2, laboratory experiments were carried out on three categories of samples extracted from the same sandstone type. They were made of quartz only, with no clay content. Consolidation and cementation degrees were the two parameters differentiating these three types of samples, as they were loosely consolidated, well-cemented or unconsolidated. Dry frame tests were performed on these three types of samples (Section 2.6.1), and allowed determining the elastic wave velocity evolution with effective stress. Combined with the porosity versus effective stress relationships, independently derived on sister plugs from the petrophysical tests (Section 2.6.2), elastic wave velocity with effective stress relationships were transformed into bulk and shear modulus relationships versus effective stress on one hand, and versus porosity on the other hand. This has been performed for the three types of samples: loosely
consolidated sandstone, well-cemented sandstone, and unconsolidated sand (with sorting upon the grain size distribution).

Figures 3.20 and 3.21 present the evolution of the bulk and shear moduli of the rock frame versus effective stress. Figures 3.22 and 3.23 present the evolution of the bulk and shear moduli of the rock frame versus porosity, for effective stress levels varying from 4.1MPa to 67.5MPa. The general trend of the dependence of elasticity with porosity is that the smaller the porosity, the larger the elastic moduli (well-cemented sandstone), and the larger the porosity, the smaller the elastic moduli (unconsolidated sand). Intermediate elastic moduli values are associated with intermediate porosity range (loosely consolidated sandstone). These figures also highlight the large dependence upon effective stress level of the relationships between elastic moduli and porosity. The higher the effective stress level, the closer to linear these relationships. Moreover, they illustrate that the stiffness of the rock is likely to be more increased by cementation rather than consolidation.

Figure 3.20: Bulk modulus versus effective stress (dry samples).
Figure 3.21: Shear modulus versus effective stress (dry samples).

Figure 3.22: Bulk modulus versus porosity (dry samples) with low and high effective stress trends.

Figure 3.23: Shear modulus versus porosity (dry samples) with low and high effective stress trends.
3.4.2: Consolidation, cementation and porosity parameters

Consolidation and cementation degrees have significant effects on the stiffness of the Lochaline core samples. Increase of cementation or consolidation degrees leads indeed to an increase of the grain-to-grain contact area, and therefore to an increase of the rock stiffness. Such increases of degrees of cementation or consolidation also lead to a decrease of porosity, and therefore to an increase of density.

Moreover, porosity can also generally vary from rock to rock without any changes of degree of cementation or consolidation. Rock texture, including grain angularity, grain roughness, grain size sorting, or grain packing greatly affect porosity, without any modification of the consolidation or the cementation of the rock (Pettijohn et al., 1987). Such variations of the rock texture also affect the stiffness and consequently the bulk and shear moduli of the rock. Consequently, as porosity also affects the stiffness of rocks, decoupling the effects on the rock stiffness of consolidation and cementation necessitates also to take into account the porosity contribution. In the following section, it is investigated if the differences in elastic moduli among samples collected from the Lochaline mine are either due to:

- variation of consolidation and cementation degrees among the samples, and their effects on the grain-to-grain contact area;
- variation of porosity among the samples;
- the combination of these two previous effects.

Lochaline samples offer the possibility to tackle this issue as all rocks come from the same initial sandstone type, and vary only upon their degree of consolidation and cementation, and upon their porosity.
3.4.3: Rock elasticity dependence on porosity (lower and upper heuristic bounds)

To quantitatively investigate this issue, a similar approach to the one adopted by Dvorkin and Nur (1996) is taken. It is based on the concept of critical porosity. The critical porosity ($\phi_c$), which corresponds to the transition between the consolidation state and the non-consolidation state of rocks, is defined as follows (Mukerji et al., 1995):

- for porosity values above $\phi_c$, the pore fluid is load-bearing, a dry rock falls apart at ambient pressure;
- for porosity values below $\phi_c$, the mineral grains are load-bearing, a dry rock does not fall apart at ambient pressure.

$\phi_c$ is determined by the grain sorting and angularity at deposition, it describes the sediment when it is first deposited before compaction and diagenesis. Typical values of critical porosity, for example, are close to 0.4 for sandstones, 0.7 for chalks, 0.9 for pumice and porous glass, or 0.02 for granites (Mavko et al., 1998).

Dvorkin and Nur (1996) used an heuristic Hashin-Shtrikman lower bound (Hashin and Shtrikman, 1963) to interpolate the elastic moduli of unconsolidated sands for a range of porosity values bounded by two extreme porosity end members: a low porosity end member (zero porosity), and a high porosity end member (critical porosity). Elastic moduli of the low porosity end member were those of quartz, and were thus stress-independent. The elastic moduli of the high porosity end member were computed by Hertz-Mindlin granular medium theory model. Hertz-Mindlin model leads to identical results to those derived by Walton model (Section 3.3) in the case of infinitely rough spheres (Mavko et al., 1998). Then, stating that the Hasin-Shtrikman lower bound was appropriate to describe materials close to suspension such as unconsolidated sands,
Dvorkin and Nur (1996) used a modification of this bound to calibrate it between both the low and the high porosity end members. This allowed prediction of the elastic moduli of unconsolidated material from the critical porosity to lower porosity values, for a given effective stress level.

In the case of the Lochaline samples, a similar approach has been adopted. The low porosity end member is identical to the one used in Dorkin and Nur's approach. This low porosity member corresponds to zero porosity, and its bulk and shear moduli values are those of quartz, respectively 38GPa and 44GPa (Carmichael, 1982). The choice slightly differs concerning the high porosity end member. The high porosity end member is directly derived from measurements performed in the laboratory on the unconsolidated sands (well-sorted sands). Elastic moduli of the high porosity end member are those measured during the dry frame test on sample SU9 at various levels of effective stress. Porosity values of the high porosity end member are those measured during the petrophysical test on sample SU3 at various levels of effective stress. This allows the use of real measurements to derive high porosity end member porosity and elastic moduli values, instead of values computed from theoretical models requiring a large number of assumptions and an accurate calibration. This also allows using as reference unconsolidated sands which are from the same initial sandstone type as both the loosely consolidated and the well-cemented sandstones.

The high porosity end member does not correspond to the critical porosity as its value varies with effective stress. It corresponds to the largest porosity that can take the disaggregated material at a given effective stress level. It is therefore only equal to the critical porosity at ambient pressure. Moreover, properties of the high porosity end member are arbitrarily chosen to be those of the well-sorted sands and not of the unconsolidated sands without any sorting upon the grain size distribution. The well-
sorted sands are actually the unconsolidated samples with quartz grains the more homogeneously distributed within the heat-shrunk Teflon jacket and therefore the more representative of the Lochaline rocks.

The principal objective of this approach is to quantitatively compare the elastic moduli of the loosely consolidated to those of the well-cemented sandstones by studying the effects of consolidation, cementation and porosity on the rock stiffness. Therefore, in contrast to the case of unconsolidated material stated by Dvorkin and Nur (1996), the Hashin-Shtrikman lower bound is not appropriate itself to relate the low porosity to the high porosity end members. More general elastic moduli trends are needed. Both the harmonic and arithmetic averages, respectively the Reuss lower bound and the Voigt upper bound, are therefore computed and compared with the elastic moduli derived from the measurements. These bounds are computed for porosity values lower than \( \phi_c \), by combining together the elastic moduli of pure quartz (low porosity end member) with those of the unconsolidated sands (high porosity end member). The average of both Voigt and Reuss bounds, the Voigt-Reuss-Hill (Hill) average (Mavko et al., 1998), is also computed as a reference. Reuss and Voigt bounds are free of assumptions upon the geometry of the material (pore network geometry, grain-to-grain contact area, etc.) and are therefore very general. Reuss bound represents the state the softest the rock can be whereas Voigt bound represents the stiffest state the rock can reach. This process of mixing together pure quartz (zero porosity) with unconsolidated sand (critical porosity) is purely heuristic and necessitates modification of the bounds to relate together both low and high porosity end members (instead of porosity values of 0 and 1).

Reuss and Voigt bounds are computed for several effective stress levels corresponding to those applied during the dry frame experiments performed on the well-sorted unconsolidated sand. Both bulk and shear moduli of the loosely consolidated and well-
cemented sandstones from Lochaline are compared with these bounds for a given effective stress level. Porosity of the high porosity end member (critical porosity) is not considered as constant anymore as porosity decreases with the increase of effective stress, as shown in Section 2.6.2.

Formulae corresponding to the modified Reuss bound, Voigt bound, and Hill average are described below. The following parameters are considered: effective stress ($\sigma$), the bulk modulus of the quartz ($K_m$), the shear modulus of the quartz ($\mu_m$), the bulk modulus, the shear modulus and the porosity of the well-sorted unconsolidated sand, respectively $K_u(\sigma)$, $\mu_u(\sigma)$ and $\phi_u(\sigma)$. Both bulk and shear moduli are finally computed for a given porosity ($\phi$) with $0 < \phi < \phi_u(\sigma)$, corresponding respectively to Reuss lower bound ($K_r$, $\mu_r$), Voigt upper bound ($K_v$, $\mu_v$), and Hill average ($K_h$, $\mu_h$), using the following relationships:

\[
\frac{1}{K_r(\sigma)} = \left(1 - \frac{\phi}{\phi_u(\sigma)}\right) - \frac{K_m}{K_u(\sigma)}, \quad (3.19a)
\]

\[
\frac{1}{\mu_r(\sigma)} = \left(1 - \frac{\phi}{\phi_u(\sigma)}\right) - \frac{\mu_m}{\mu_u(\sigma)}, \quad (3.19b)
\]

\[
K_v(\sigma) = \left(1 - \frac{\phi}{\phi_u(\sigma)}\right)K_m + \left(\frac{\phi}{\phi_u(\sigma)}\right)K_u(\sigma), \quad (3.19c)
\]

\[
\mu_v(\sigma) = \left(1 - \frac{\phi}{\phi_u(\sigma)}\right)\mu_m + \left(\frac{\phi}{\phi_u(\sigma)}\right)\mu_u(\sigma), \quad (3.19d)
\]

\[
K_h(\sigma) = \frac{K_r(\sigma)}{2} + \frac{K_v(\sigma)}{2}, \quad (3.19e)
\]

\[
\mu_h(\sigma) = \frac{\mu_r(\sigma)}{2} + \frac{\mu_v(\sigma)}{2}. \quad (3.19f)
\]
Figures 3.24 to 3.26 present plots of the bulk and shear moduli computed by Reuss bound, Voigt bound, and Hill average versus porosity, derived from the experiments performed on the unconsolidated sand (well-sorted). It also presents the elastic moduli measured on the loosely consolidated and well-cemented sandstones from Lochaline, for the following effective stress levels: 4.1MPa, 20.7MPa, and 67.5MPa. These figures show that data from the loosely consolidated sandstone do not match the same heuristic bound as those from the well-cemented sandstone: loosely consolidated sandstone data are close to Hill average, whereas well-cemented sandstone data are close to Voigt bound. Moreover, these figures highlight that the relative positions of the elastic moduli data to the bounds are dependent upon effective stress, especially for the loosely consolidated sandstone at low effective stress levels.

These observations suggest that variations of elastic moduli among samples are not related to variations of porosity only. If it were the case, for a given effective stress level, the elastic moduli would follow the same trend. Moreover, as Reuss bound corresponds to the softest state the rock can reach, it may represent the trend the unconsolidated sand would follow with porosity changes only (due to variations of grain angularity, roughness, sorting, or packing). Elastic moduli of the loosely consolidated sandstone do not follow Reuss bound, even at low effective stress levels. As it is possible to manually disaggregate this loosely consolidated sandstone, this leads to the conclusion that a small degree of consolidation significantly increases the stiffness of a rock. Concerning the well-cemented sandstone, data are close to the stiffest state a rock can be, even at low effective stress levels.
Figure 3.24: Elastic moduli versus porosity (dry samples). Comparison with theoretical bounds at 4.1MPa. (a) Bulk modulus. (b) Shear modulus.

Figure 3.25: Elastic moduli versus porosity (dry samples). Comparison with theoretical bounds at 20.7MPa. (a) Bulk modulus. (b) Shear modulus.

Figure 3.26: Elastic moduli versus porosity (dry samples). Comparison with theoretical bounds at 67.5MPa. (a) Bulk modulus. (b) Shear modulus.
3.4.4: Quantification of the effects of consolidation and cementation on the rock elasticity

A methodology to quantify the stiffness of a rock is proposed. It consists in determining the relative position of the elastic moduli to the Reuss lower and Voigt upper bounds by fitting the elastic moduli to intermediate trends. These intermediate trends, bulk modulus $K(\sigma)$ and shear modulus $\mu(\sigma)$, are computed, for a given effective stress level, by introducing a weight factor ($\zeta$), the stiffness parameter, varying from 0 to 10, following a similar approach than the one adopted by Marion and Nur (1991). Computation of these trends is presented as follows:

$$K(\sigma) = \frac{(10 - \zeta)K_r(\sigma) + \zeta K_v(\sigma)}{10},$$  \hspace{1cm} (3.20a)

$$\mu(\sigma) = \frac{(10 - \zeta)\mu_r(\sigma) + \zeta \mu_v(\sigma)}{10}. \hspace{1cm} (3.20b)$$

$\zeta$ is then derived for each set of samples (loosely consolidated and well-cemented sandstones) at each effective stress level, its value gives the position of the elastic moduli relative to the two extreme bounds. If $\zeta$ is close to 0, it indicates the rock is close to the softest state the rock can reach, whereas if $\zeta$ is close 10, it indicates the rock is close to the stiffest state it can reach. $\zeta$ represents therefore a measure of the stiffness of a core sample, independently of porosity.

Example of determination of $\zeta$ at 20.7MPa for both the loosely consolidated and well-cemented sandstones is illustrated by Figure 3.27. Concerning the bulk modulus, values of $\zeta$ are respectively 5.1 and 9.97 for both the loosely consolidated and the well-cemented sandstones, and 5 and 8.49 for the shear modulus. Plots of $\zeta$ with effective
stress, corresponding to the bulk and shear moduli of both the loosely consolidated and the well-cemented sandstones, are presented in Figure 3.28.

Figure 3.27: Elastic moduli versus porosity (dry samples). Determination of the sample stiffness at 67.5MPa. (a) Bulk modulus. (b) Shear modulus.

Figure 3.28: Stiffness parameter versus effective stress (dry samples). (a) Bulk modulus. (b) Shear modulus.
3.5: Interpretation of the pressure dependence of the rock frame

3.5.1: Stiffness and compliance

Stress-sensitivity of the rock frame is an important ingredient in predicting the effects of fluid substitution on wave velocities for time-lapse seismic. In particular, understanding the pressure-sensitivity of reservoir rocks has been a popular area of research for many decades. For the rock frame, two main theoretical schools of thought can be distinguished. The first one deals with contact theory (Mindlin, 1949; Digby, 1981; Walton, 1987). It is based on strong assumptions (identical and spherical rigid spheres), and is mainly relevant to unconsolidated material, as illustrated by Section 3.3. The second one is based on inserting inclusions into the matrix material using effective medium theory. These inclusions (microcracks or pores) are modelled by idealized geometries, such as oblate or prolate spheroids (for example Eshelby, 1957; Kuster and Toksöz, 1974; Berryman, 1980a; Berryman, 1980b) or non-elliptical shapes (Walsh, 1965; Mavko and Nur, 1978). Both schools assemble models and resultant pressure-sensitivity in terms of stiffness. Pressure-sensitivity in terms of stiffness of the Lochaline samples derived from the rock physics measurements has been incorporated into a heuristic porosity dependence model to study the rock frame sensitivity with pressure as a function of porosity, as illustrated by Section 3.4. This effective medium approach is used in Section 3.5.3 to interpret the rock frame sensitivity of the Lochaline samples with pressure in terms of stiffness. The interpretation is based on the stiffness parameter ($\zeta$).
An alternative emerging approach expresses the effective stress dependence in terms of weaknesses or excess compliances inserted into the otherwise competent rock (Mavko et al., 1995; Sayers and Kachanov, 1995). It has been used to simulate the effect of cracks and fractures (Schoenberg and Sayers, 1995) and also contacts in shales (Sayers, 1999). The latter approach is used in Section 3.5.4 to recover the excess rock compliance, irrespective of their origin, from the rock physics measurements performed in the laboratory on the Lochaline samples.

3.5.2: Pore network analysis

S.E.M. analysis of thin sections helps interpreting the dependence of the Lochaline rock elasticity with effective stress. Figures 3.29 and 3.30 highlight the presence of three main types of pores within the loosely consolidated sandstone: macropores, micropores and connective pores. Macropores consist of high aspect ratio pores, micropores consist of intra-granular cracks, and connective pores consist of low aspect ratio pores. These low aspect ratio pores (flat pores) correspond to pre-existing grain-to-grain contacts established during the consolidation process.

Figure 3.31 is an example of a thin section of the well-cemented sandstone. It highlights the presence of pores of high aspect ratio, and the absence of intra-granular cracks, as cracks have been overwhelmed by cement during the post-depositional silica cementation process. Moreover, few connective pores are present but they are not as numerous as they are in the loosely consolidated sandstone. They are also not as long and wide, as they have been filled by cement. The ability of grain-to-grain contact area to increase with effective stress is therefore not as high as it is for the loosely consolidated sandstone.
Thin sections of the unconsolidated sand could not physically be made. However, as these samples are made of a randomly distributed loose pack of quartz grains, it is possible to estimate the characteristics of their pore network. They are probably made of many high aspect ratio pores, without any intra-granular cracks (or just a few), due to both the disaggregation and the sieving processes, and without any pre-existing grain-to-grain contacts.

**Figure 3.29:** Thin section of a loosely consolidated sandstone from Lochaline. Illustration of three main types of pores: connective pores, micropores and macropores.

**Figure 3.30:** Thin section of a loosely consolidated sandstone from Lochaline. Illustration of connective pores.
3.5.3: Stiffness-based interpretation

Figure 3.28 highlights that the stiffness parameter ($\zeta$) is stress dependent as it increases with effective stress. However, the degree of stress-sensitivity differs from the loosely consolidated to the well-cemented sandstones. Concerning the loosely consolidated sandstone, at low effective stress levels, a small increase of effective stress leads to a large increase of $\zeta$ and therefore to a large increase of the elastic moduli. This is due to the presence of the connective pores, as illustrated by thin sections (Figures 3.29 and 3.30). These connective pores consist of pre-existing contacts between adjacent grains, and a small increase of effective stress allow these contacts to be pushed together, which considerably increases the area of grain-to-grain contacts. This effect which produces a reduction of the void at contacts between grains leads to an increase of the bulk modulus. Moreover, this also leads to an increase of the grain adherence at contacts and therefore to an increase of the shear modulus. Superposed to this grain-to-grain contact closure is the closure of intra-granular cracks. When effective stress values reaches a level for which the majority of intra-granular cracks and grain-to-grain contacts are closed, the rate of increase of grain-to-grain contact area with effective stress becomes very low. Elastic moduli do not increase anymore; they stay almost

---

Figure 3.31: Thin section of a well-cemented sandstone from Lochaline.

Illustration of macropores.
constant as they reach a limit. This is highlighted by Figure 3.28, as this latter shows that \( \zeta \) reaches a stable value for differential pressure values larger than 20.7MPa.

Concerning the well-cemented sandstone, trends of elastic moduli with effective stress are different to those described in the case of the loosely consolidated sandstone, and their absolute values are larger (Figure 3.28). Observations of thin sections suggest that there is no presence of microcracks, as they have been overwhelmed and filled by quartz cement during the cementation process (Figure 3.31). Macropores are the main types of pores within this well-cemented sandstone, which explains its response to effective stress increase is different to this of the loosely consolidated sandstone. Surprisingly, the bulk modulus and the shear modulus do not present the same evolution with effective stress. The bulk modulus is almost constant with effective stress whereas the shear modulus increases with effective stress. These relationships suggest that contacts between grains are almost completely established in the sandstone even at ambient pressure, before the sample is subject to any effective stress increase. Grain-to-grain contact area increase with effective stress is therefore very small. Pore space reduction with effective stress is therefore almost negligible and the bulk modulus stays consequently constant with effective stress. It is however not small enough to avoid increase of adherence at contacts between grains, and an increase of shear modulus increase with effective stress. Figure 3.28 highlights the high values of \( \zeta \) compared to those of the loosely consolidated sandstone. \( \zeta \) describes the stiffness of a material, the well-cemented sandstone is almost as stiff as any sample with the same porosity can be: values of \( \zeta \) related to the bulk modulus are very close to the maximum value it can theoretically reaches (10).

Elastic moduli relationships with effective stress are also different in the case of the unconsolidated sands (Figures 3.20 and 3.21). Absolute values of the elastic moduli are
considerably lower than those corresponding to the two other types of sandstones (loosely consolidated and well-cemented). Moreover, the increase of elastic moduli with increase of effective stress is regular on the whole range of effective stress. There is no abrupt increase of stiffness at low effective stress levels followed by a constant level at higher effective stress, as in the case of the loosely consolidated sandstone. This can be explained by the absence of pre-existing grain-to-grain contact area and intra-granular cracks within the unconsolidated sands, as grains were put together randomly. This also explains why a smooth empirical grain-to-grain contact number increase relationship with effective stress, valid on the whole range of effective stress, has been detected in the case of the unconsolidated sand, as illustrated by Section 3.3.

To summarise, the nature of the diagenesis process affecting a rock (consolidation or cementation) is responsible for the differences of evolution of rock stiffness with effective stress between the loosely consolidated, well-cemented sandstones, and the unconsolidated sands, extracted from the same rock type. Elastic moduli values are dependent on the consolidation, cementation, porosity and effective stress levels. Effective stress increase leads to an increase of the elastic moduli of the rock, but the rate of increase is dependent upon the diagenesis of the rock, whether it is consolidated or not, cemented or not. Computation of the stiffness parameter ($\zeta$) allows quantification of the influence of both degrees of consolidation and cementation on the stiffness of both the loosely consolidated and the well-cemented sandstones, at various effective stress levels. It results from this analysis that, independently of porosity, rock stiffness is more sensitive to the cementation process than to the consolidation process, as the largest values of $\zeta$ correspond to the well-cemented sandstone. Consolidation and cementation directly control the stiffness and therefore the elastic wave velocities of a rock whereas porosity is more likely to act as a secondary parameter.
3.5.4: *Compliance-based interpretation*

In the previous section, the interpretation of the pressure-sensitivity of the rock frame has been performed in terms of stiffness. In this section, it is carried out in terms of excess compliance. From the elastic moduli computed as a function of effective stress for the three types of Lochaline samples, both excess normal and tangential compliances are calculated after compensation for host matrix softening due to porosity evolution with effective stress, by using differential effective medium theory (Kirstetter and MacBeth, 2001).

3.5.4.1: *From the observed elastic moduli to the excess compliance*

From the computation of the bulk and shear moduli for the three types of samples, the following methodology is used to back out the excess rock compliance as a function of effective stress. It is observed that both elastic moduli tend to a constant value at high effective stress when most grain-to-grain contacts at a point or over an area are closed and/or sufficiently strengthened. This asymptote also marks the point at which all intra-granular cracks, open discontinuities and soft pore space have closed. At high effective stress, the material resembles a quartz block containing a complicated set of holes and channels, and corresponding elastic moduli values are given by parameter $A$ of Equation 3.25 of Section 3.7, whilst at zero effective stress they are given by $A-B$.

The compliance of a material is defined following the approach of Sayers and Kachanov (1995). The total compliance is equal to the sum of the compliance of the host matrix of the material and of the excess compliance due to the weaknesses in the material (contacts and cracks). Compliant grain-to-grain contacts resemble thin cracks, similar to the compliant cracks that may be present within the grains. It is associated with soft porosity whereas host matrix compliance is associated with hard porosity, as illustrated...
by Figure 3.32. At high effective stress, as there is zero excess compliance for contacts and cracks, the total compliance of this state is equal to the host matrix compliance of the material. As pressure is released, compliance is created due to the weakening or parting of contacts, the opening of microcracks (true excess compliance), but also to a slight increase in the host matrix compliance due to porosity increase.

Figure 3.32: Schematic of the hard and soft porosity of a rock.
Host matrix compliance increase with porosity is predicted using differential effective medium theory. The observed elastic moduli are corrected by inserting additional spherical void pockets into the background medium, and fitting them to the experimentally determined porosity evolution with effective stress. This leads to the adjusted elastic moduli $K^*(\sigma)$ and $\mu^*(\sigma)$. The corrected host matrix compliance terms $Z_{11}^{HC}(\sigma)$ and $Z_{12}^{HC}(\sigma)$ are then computed as a function of effective stress using equation 3.21 adapted from Sayers and Kachanov (1995):

$$Z_{11}^{HC}(\sigma) = \frac{3K^*(\sigma) + \mu^*(\sigma)}{9K^*(\sigma)\mu^*(\sigma)},$$  \hspace{1cm} (3.21a)

$$Z_{12}^{HC}(\sigma) = \frac{2\mu^*(\sigma) - 3K^*(\sigma)}{18K^*(\sigma)\mu^*(\sigma)}. \hspace{1cm} (3.21b)$$

The excess compliance can now be calculated by differentiating the corrected host matrix compliance at each effective stress from the corrected host matrix compliance predicted for infinite pressure. This excess compliance is finally transformed into two forms (Sayers and Kachanov, 1995), the excess normal compliance $Z_N(\sigma)$ and the excess tangential compliance $Z_T(\sigma)$:

$$Z_N(\sigma) = Z_{11}^{HC}(\sigma) - Z_{11}^{HC}(\infty), \hspace{1cm} (3.22a)$$

$$Z_T(\sigma) = Z_{11}^{HC}(\sigma) - Z_{11}^{HC}(\infty) - 3(Z_{12}^{HC}(\sigma) - Z_{12}^{HC}(\infty)). \hspace{1cm} (3.22b)$$

$Z_N(\sigma)$ and $Z_T(\sigma)$ are averaged over the entire contact and crack distribution, which in this case is considered to be random. This means that the system is assumed to be isotropic, which is relevant as all experiments were carried out under a hydrostatic loading. The results are displayed in Figures 3.33 and 3.34, in which plots are based on the fit of Equation 3.25 to the experimental data for pressure values between 0 and 70MPa.
Figure 3.33: Excess normal and tangential compliances $Z_N$ and $Z_T$ versus effective stress.

Figure 3.34: Excess normal and tangential compliances $Z_N$ and $Z_T$ (normalized) versus effective stress.
3.5.4.2: Interpreting the excess compliance

Excess compliance shows, as expected, a distinct downward progression from the initial zero pressure value. Least excess is exhibited by the well-cemented material, followed by the loosely consolidated and then the unconsolidated samples (Figure 3.33). For each case, both the excess normal and tangential compliances appear to have fairly similar magnitudes and effective stress dependence. Interestingly, the normalised trends show that the loosely consolidated rock possesses the largest pressure-sensitivity at low effective stress values, followed by the well-cemented and then the unconsolidated samples (Figure 3.34). The latter progresses less rapidly as the grains are free to slide and rotate into more stable, stiffer configurations, whilst the former has more difficulty as the grains are locked at contact points by pressure dissolution features. The elastic response of the well-cemented sample is dominated by grain-to-grain contacts spread over an area due to quartz overgrowths, and these contacts are less compliant than those present in the loosely consolidated material. This supports the fact that no intra-granular cracks have been noticed on thin sections performed on well-cemented sample, and are not expected to be present in the unconsolidated material.

More insight into this micro-deformational process is obtained by plotting the ratio of excess normal to tangential compliance $Z_n/Z_T$ as a function of effective stress (Figure 3.35). For cracks in a pure quartz host rock, theory predicts a ratio $Z_n/Z_T$ to be close to unity (MacBeth, 2001) whereas for spherical quartz grains, Digby (1981) predicts $Z_n/Z_T$ of zero for no initial bonding and then for no slip at the contacts a value close to unity. Shear asymmetry (Manificat and Guéguen, 1998) predicts $Z_n/Z_T$ to be half of these values. Table 3.1 highlights excess compliance values recorded by several authors for shales. All measurements performed on the Lochaline rock fall within the range in this table at low pressure levels, with a progression beyond unity at higher pressure levels.
for the unconsolidated sample. The values corresponding to the loosely consolidated case tend towards those of the well-cemented case at higher pressure levels.

Effective stress  \( \frac{Z_N}{Z_T} \)  \( \frac{Z_{n}/Z_{t}}{Z_{av}/Z_{t}} \)  Comments
5 to 80  0.26  0.30  0.29  fully saturated, shale (1)
5 to 80  0.33  0.41  0.37  fully saturated, shale (1)
20 to 100  0.47  0.58  0.52  air-dry conditions, shale (1)
20 to 100  0.54  0.63  0.58  air-dry conditions, shale (1)
5 to 30  0.60  0.80  0.68  air-dry conditions, mature+cracks, shale (1)
6 to 24  0.70  0.92  -  air-dry simulated fractures with lucite plates (2)

Table 3.1: \( \frac{Z_N}{Z_T} \) over a range of effective stress values. Comparison with other works: (1) after Sayers (1999); (2) after Hsu and Schoenberg (1993).

3.5.4.3: Comparison with permeability measurements

A comparison is made between the excess normal and tangential compliances and the permeability to oil measurements (Figure 3.36). The permeability decreases in proportion to compliances for effective stress levels up to 10MPa (loosely consolidated material) and 15MPa (unconsolidated material) whilst at larger pressure levels (lower compliances), there is a transition in the physical regime, and permeability decreases much more rapidly with compliance. This transition zone may correspond to the
complete closure of a significant number of grain-to-grain contacts, thus drastically lowering the permeability of the material. This also contributes to a decrease of compliance but at a much smaller rate, compliance being more sensitive to the larger changes of grain-to-grain contact area that occur at low pressure levels.

**Figure 3.36**: Permeability versus excess normal and tangential compliances $Z_N$ and $Z_T$ (normalized). Effective stress values are indicated for reference purposes.

### 3.5.4.4: Conclusion

Excess compliance provides a natural way of interpreting rock frame sensitivity with effective stress. It acts as a diagnostic tool for the internal micro-structural deformation process at the laboratory scale. The compliance relates directly to the rock properties and is both physical and intuitive. Excess compliance acts as a primary controlling parameter for a wide range of cases, porosity being secondary. Pressure-sensitivity is controlled by populations of contacts (or asperities) regardless of whether the rock is unconsolidated, loosely consolidated or well-cemented. Decreases in the elastic moduli with decreasing effective stress are interpreted as a rise in the excess compliance produced by a progressive number of rock defects: the weakening or parting of grain-to-grain contacts, and the opening of intra-granular cracks. The pressure dependence of
the normal and tangential compliances, together with their ratio, are mostly consistent with the expected magnitude and evolution predicted by other compliance-based studies. The nature of the pressure-sensitivity is revealed using excess compliance and the $Z_N/Z_T$ ratio. This approach has been used previously for cracks or fractures, and contacts in shales, but has been shown here to be valuable for sandstones and sands. Such compliance-based analysis might be used for further work to decouple the effects of intra-granular cracks and grain-to-grain contacts on the pressure-sensitivity of rocks using an asperity-deformation model, as for example the "bed-of nails" model (Gangi, 1981; Carlson and Gangi, 1985).

3.6: Elastic moduli extension to a wider range of porosity values

As reservoirs are not homogeneous, rock elastic and petrophysical properties vary with location. However, available cores to be tested in the laboratory are not always numerous enough to represent the whole variability of elastic or petrophysical properties within reservoirs. This may prevent modelling accurately time-lapse effects in the scope of seismic reservoir monitoring projects. In such cases, especially when only just a few cores are available for laboratory experiments, it might be useful to try predicting the variation of rock elastic properties with parameters whose heterogeneity has been geologically modelled, by geostatistical means for instance. Porosity being such a parameter, it is more accurate to populate the reservoir model by the predicted elastic moduli values as a function of porosity instead of assessing constant elastic properties, derived directly from the laboratory experiments, within the whole model. The approach of rock elastic moduli prediction to a wider porosity range, taken into account consolidation and cementation degrees, is described as follows.
3.6.1: Methodology

The proposed method is a graphical approach, based on the computation of the stiffness parameter ($\zeta$), presented in Section 3.4.4. Figure 3.28 shows that $\zeta$ (which is an estimate of the stiffness of a rock, at a given effective stress level) allows distinguishing loosely consolidated to well-cemented samples, independently of porosity. The more cemented the sample, the higher the values of $\zeta$. A method to predict the variability of the elastic moduli of clean sandstones with porosity is illustrated by Figure 3.37. It is based on the assumption that both degrees of consolidation or cementation are porosity-independent and are similar to those of the tested sample in the laboratory. The approach consists in assessing elastic moduli values for a given porosity by following the trend defined by constant $\zeta$ fitted to the data extracted from samples tested in the laboratory. The stiffness parameter ($\zeta$) being stress dependent, the process has to be performed independently for both bulk and shear moduli, for each effective stress level, to compute the predicted elastic moduli evolution with effective stress. Figure 3.37 illustrates the approach of the bulk and shear moduli prediction at a porosity value of 0.1 at the effective stress level of 20.7MPa, for the Lochaline well-cemented sandstone. Predicted values are respectively 28GPa and 27.8GPa for both the bulk and the shear moduli.
Figure 3.37: Prediction of the elastic moduli of the well-cemented sandstone for a porosity of 0.1 (assuming an identical stiffness). (a) Bulk modulus. (b) Shear modulus.

3.6.2: Clashach sandstone test

To estimate the validity of this approach, dry frame experiments were performed on a rock with some similar characteristics to those of the Lochaline Sandstone, the Clashach Sandstone. Clashach Quarry is situated in North-East Scotland, near Hopeman on the Moray Firth coast. Clashach Sandstone is from the New Red Sandstone of Permian age. It is a fine-to-medium grain, isotropic, well-sorted, consolidated clean sandstone. Grains are mainly quartz grains (95%). Feldspar (mainly plagioclase) is also present (4%). Its clay content is smaller than 1% (Tao et al., 1995), and its ambient porosity range is between 0.12 and 0.2. Figure 3.38 presents a thin section of the Clashach Sandstone. It highlights presence of quartz overgrowths and cement (quartz). Grain-to-grain contacts and pressure dissolution sutures are also present. Cementation features explain why Clashach Sandstone is not friable, in contrast to the Lochaline loosely consolidated sandstone, and therefore could not be manually disaggregated without damaging the grains. Moreover, a few connective pores, similar to those of the Lochaline loosely consolidated sandstone can also be noticed on this thin section.
Clashach sandstone therefore presented cementation features close to those of the Lochaline well-cemented sandstone but with a smaller degree of cementation, and a higher porosity. This allowed testing the methodology of extrapolating elastic moduli to a wider range of porosity for a given stiffness, described in Section 3.6.1. According to this approach, computed $\zeta$ values derived from the well-cemented sandstone from Lochaline for the Clashach sandstones should be a bit smaller than those derived from the well-cemented sandstone, as the cementation degree is smaller. They should also be much larger to those derived from the Lochaline loosely consolidated sandstone.

**Figure 3.38:** Thin section of a Clashach Sandstone. Illustration of connective pores and macropores.
ξ values have been calculated following the same process used for the Lochaline samples for two Clashach samples: samples CL2 and CL4. Their porosity values at ambient condition were respectively 0.17 and 0.14, close to the porosity of the loosely consolidated sandstone. Dry frame experiments were carried out on these two samples, with effective stress increase up to 51MPa (sample CL4) and 67.5MPa (sample CL2). Sample preparation was identical to this performed on the Lochaline Sandstone. A small amount of water was introduced into the samples before testing to avoid any ultradry rock artefacts. This allowed comparing measurements performed in the same conditions as those performed on the Lochaline samples. Porosity relationships with effective stress were derived from petrophysical tests carried out on sister Clashach samples with similar initial porosity. Figure 3.39 presents the bulk and shear modulus evolutions with effective stress of the Clashach sandstones. ξ is then calculated and results are reported in Table 3.2, with those derived from the Lochaline sandstones.

Figure 3.39: Elastic moduli versus effective stress (dry Clashach sandstones). (a) Bulk modulus. (b) Shear modulus.
<table>
<thead>
<tr>
<th>Effective stress (MPa)</th>
<th>Stiffness parameter (bulk modulus)</th>
<th>Stiffness parameter (shear modulus)</th>
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<th>Stiffness parameter (shear modulus)</th>
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Table 3.2: Stiffness parameter (bulk and shear moduli) versus effective stress (dry Lochaline and Clashach sandstones).
Table 3.2 shows that $\zeta$ values associated with the bulk modulus of the sample CL2 are just over 10 for effective stress levels larger than 23.4MPa, whereas 10 is the theoretical largest value $\zeta$ can reach for a given porosity. This may be due to the fact that Clashach and Lochaline samples, even if they are both clean sandstones, are not extracted from the same sandstone type. For example, Lochaline rock is indeed made of more than 99% quartz whereas Clashach sandstone quartz content is 95%. This may affect comparisons between samples. Error measurements on the directly measured parameters (P- and S-wave wave travel-time, pore volume squeeze-out) also induce errors in $\zeta$ and can be partly responsible for this exceeding of the value of 10.

Figures 3.40 presents the plot of the stiffness parameter ($\zeta$) corresponding respectively to the bulk and shear moduli for the Lochaline loosely consolidated and well-cemented sandstones, and for the Clashach samples. This figure shows that $\zeta$ values corresponding to the bulk modulus derived from both Clashach samples have very similar values than those derived from the Lochaline well-cemented sandstone on the whole range of effective stress. This is not the case for the shear modulus. Values of $\zeta$ are close but definitively smaller, especially at large effective stress levels. However, stiffness values of the Clashach samples are closer to those of the well-cemented sandstone than to those of the loosely consolidated sandstone whereas Clashach porosity values are closer to those of the Lochaline loosely consolidated sandstone. This confirms the statements that rock stiffness is more sensitive to cementation than to consolidation. Porosity, contrary to consolidation and cementation, is thus not the critical parameter to derive the stiffness of core samples. Differences between values of $\zeta$ corresponding to the shear modulus with effective stress between the Clashach samples and the Lochaline well-cemented sandstone may be explained by a difference of cementation degree. The fact that the values of $\zeta$ corresponding to the bulk modulus
with effective stress between the Clashach samples and the Lochaline well-cemented sandstone are very similar is more surprising. It may indicate that variations of cementation degree influence more the shear modulus than the bulk modulus of a rock.

This example shows that the computation of the stiffness parameter ($\zeta$) allows distinguishing cementation effects from consolidation effects independently of porosity. However, it remains difficult to quantify precisely both consolidation and cementation degrees of a rock. This difficulty limits the accuracy of the approach described above to extend values of elastic moduli for a wider porosity range, on samples with different origins. A similar approach may also be extended to quantify the changes of stiffness due to clay content.

(a) (b)

Figure 3.40: Stiffness parameter versus effective stress (dry samples). Comparison between Clashach and Lochaline sandstones. (a) Bulk modulus. (b) Shear modulus.
3.7: Empirical relationships of the elastic moduli versus effective stress

The purpose of this section is to determine a general empirical relationship linking both bulk and shear moduli to effective stress for the three types of Lochaline samples (loosely consolidated, well-cemented sandstones and unconsolidated sands). Eberhart-Phillips et al. (1989), Freund (1992) or Jones (1995) have shown that a relationship can model the evolution of both P- and S-wave velocities with effective stress ($\sigma$), in the case of clastic consolidated sandstones:

$$V_p = A_p + K_p \sigma - B_p e^{-D_p \sigma}, \quad (3.23a)$$
$$V_s = A_s + K_s \sigma - B_s e^{-D_s \sigma}, \quad (3.23b)$$

with fitting parameters ($A_p$, $K_p$, $B_p$, $D_p$ and $A_s$, $K_s$, $B_s$, $D_s$).

Khaksar et al. (1999) simplified Equation 3.23 to Equation 3.24 by setting parameters $K_p$ and $K_s$ at 0. They shown that such a relationship provides a good fit to real data and more realistic wave velocity predictions at high effective stress levels:

$$V_p = A_p - B_p e^{-D_p \sigma}, \quad (3.24a)$$
$$V_s = A_s - B_s e^{-D_s \sigma}. \quad (3.24b)$$

In this study, a similar formula is used to model the dependence of both bulk and shear moduli with effective stress measured on the dry samples:

$$K = A_1 - B_1 e^{-D_1 \sigma}, \quad (3.25a)$$
$$\mu = A_2 - B_2 e^{-D_2 \sigma}. \quad (3.25b)$$

Parameters $A_1$ and $A_2$ correspond respectively to the values of the bulk and shear moduli at infinity effective stress levels, parameters $B_1$ and $B_2$ correspond to the
difference between values at infinity and zero effective stress levels. Parameters $D_1$ and $D_2$ are related to the closure of grain-to-grain contacts and intra-granular cracks. This model provides a good fit with the three sets of Lochaline samples (loosely consolidated, well-cemented sandstones, and unconsolidated sands) and also with the Clashach samples. This is illustrated by Table 3.3. This table presents the values of the fitting parameters, as well as the associated correlation coefficients (R), as defined in Appendix 1. Figure 3.41 presents plots of the bulk and shear modulus versus effective stress compared to those of the calibrated model in the case of the Lochaline loosely consolidated sandstone (dry samples).

(a)

(b)

**Figure 3.41:** Elastic moduli versus effective stress (dry loosely consolidated sandstone). Comparison with the empirical model. (a) Bulk modulus. (b) Shear modulus.
Plots of parameters $A_1$, $A_2$, $B_1$, $B_2$, $D_1$ and $D_2$ as a function of ambient porosity are presented in Figure 3.42. Good correlation with ambient porosity is obtained for parameters $A_1$, $D_1$, $A_2$ and $D_2$ whereas the correlation is poor for parameters $B_1$ and $B_2$.

Equation 3.25 provides a simple formula to model elastic moduli relationships with effective stress for samples with completely different characteristics. This empirical model is useful to be used as input into Gassmann’s equation for different effective stress levels to predict the P-wave velocity dependence on fluid effects.

![Plots of parameters as a function of porosity](image)

**Figure 3.42**: Parameters of the empirical model as a function of porosity.
Table 3.3: Empirical model parameters for the elastic moduli of the well-cemented sandstone (Wc), loosely consolidated sandstone (Lc), unconsolidated sands (SU10 and SU9) and Clashach sandstone (CL4 and CL2) with corresponding correlation coefficients (R). (*) indicates that the first data point at 1.4MPa has not been considered for the calculation.

### 3.8: Conclusions

Based on the analysis of rock physics results derived from laboratory experiments, performed on clean sandstones and sands, this chapter has highlighted that there are a large number of parameters influencing the elastic properties of rocks. These parameters include pore fluid content, effective stress, heterogeneity of saturation distribution, degree of consolidation and degree of cementation. This chapter has illustrated that the effects of these parameters on the elastic wave velocities can be modelled and predicted. Gassmann’s theory leads to accurate estimation of fluid effects on P- and S-wave velocities. The effects of fluid saturation distribution (uniform or patchy) have been studied, the type of saturation distribution greatly influences P-wave velocity of fluid-saturated rocks, especially when gas is present. Granular medium theory after calibration can accurately model the effects of effective stress on elastic
wave velocities on dry unconsolidated sands. Cementation has been found to affect the rock stiffness more than the consolidation process. Their effects have been studied and quantified in terms of stiffness and in terms of compliances.
Chapter 4: Dynamic Reservoir Modelling for Flow Simulation

This chapter focuses on the flow simulation of 2-D reservoir models, representing a geological outcrop of the Book Cliffs of Eastern Utah. Sensitivity analysis is carried out to consider the influence of flow simulation parameters on the flow simulation results. These parameters include the size of the grid blocks, the hydrocarbon recovery process, and the type of fluids. Their role and importance in the process of building the dynamic models are carefully reviewed in this chapter. These dynamic models provide the framework of reservoir models in which rock physics data measured in the laboratory (Chapter 2 and Chapter 3) are incorporated to simulate the corresponding elastic time-lapse response (Chapter 5). Chapter 4 respectively describes:

- the geological framework of the reservoir models;
- the building of dynamic models for flow simulation;
- the properties of the fluids;
- the results of the flow simulation.

4.1: The Book Cliffs

4.1.1: Geological framework

The reservoir model used in this thesis is based on the interpretation of photopanels of the Blaze Canyon outcrop by Stewart (1998). Sediments comprising the outcrop are of Upper Cretaceous (Campanian) age. They are part of the Blackhawk and Price River Formations of the Mesaverde group, Book Cliffs, Eastern Utah, U.S.A. Sediment facies
are either shoreface or fluvial, depending of changes in base level (combination of sea level, subsidence and sediment supply) during deposition. The Blaze Canyon outcrop illustrates the stratigraphic relationship that may occur between these two types of sediments in such depositional environment.

4.1.2: Formation of the Book Cliffs

From the late Triassic to late Cretaceous, sedimentation in Utah was controlled by the fold and thrust belt of the Sevier Orogenic belt, established during the late Triassic, and situated to the West of the area of study (Couples et al., 1999). From the late Cretaceous, the Cretaceous Western Interior Seaway was formed parallel to the Sevier Orogenic Belt, during subduction of the Farallon Plate beneath the western margin of the North America Plate. Stretching from the Gulf of Mexico in the South to the Canadian Arctic in the North, the Cretaceous Western Interior Seaway flooded the earlier continental basins (Couples et al., 1999). Successive phases of thrusting along the Sevier Orogenic Belt then provoked loading of the basin margin and caused clastic sediments to progress eastwards into the basin. A combination of subsidence rate, sea level and sediment supply variations led to a succession of transgression and regression, and finally to a series of stacked shoreface sequences and parasequences, under a warm temperate to sub-tropical climate (Couples et al., 1999). Shallow marine sediments were also firstly partially incised, and the resulting incised valleys were filled by fluvial and estuarine facies (Van Wagoner, 1995). Through intermittent progradation, the shoreline advanced across the basin forming the Book Cliffs until the Laramide uplifts of the Late Cretaceous and Early Tertiary (Stewart, 1998).
4.2: The Blaze Canyon outcrop

4.2.1: Location and description

The Book Cliffs forms a major South-facing escarpment in Eastern Utah. In the area of the Blaze Canyon outcrop, they rise to heights of 220m above the lowlands. The Blaze Canyon outcrop forms the eastern cliff-face of a NW to SE trending canyon. Blaze Canyon is located 6km from Thompson Canyon (Figure 4.1). The Blaze Canyon outcrop profile starts at the base with the Mancos shales and passes upwards through the component sandstone, shales and coal members of the Blackhawk Formation (Grassy and Desert Members), which record the progradation of the Late Cretaceous shoreline. The cliffs then culminate in the bench-forming Castlegate Sandstone and in the Buck Tongue Shales of the Price River Formation (Figure 4.2).

Figure 4.1: Map of Utah with location of the Book Cliffs (after Stewart, 1998).
Figure 4.2: Schematic stratigraphy of the Upper Cretaceous rocks in the Book Cliffs area (from Couples et al., 1999).

### 4.2.2: Major sequence sets

Interpretations of sequence stratigraphy and depositional facies architecture of the Book Cliffs have been the object of many publications. For example, Van Wagoner (1991; 1995) and O’Byrne and Flint (1995), focusing their analysis on the study of parasequence stacking patterns, positions of sequence boundaries, and facies associations, have divided the stratigraphy of the Grassy Member, Desert Member and Castlegate Sandstone into several sequence sets (Figure 4.3).

Figure 4.3: Sequence stratigraphy and lithostratigraphy interpretation of the Blaze Canyon outcrop area (from Van Wagoner, 1995).
Sequence sets of interest for the Blaze Canyon outcrop are:

- the Grassy highstand sequence set (named for the Grassy Member of the Blackhawk Formation) below the Desert sequence boundary;
- the Desert lowstand sequence set between the Desert and Castlegate sequence boundaries;
- the Castlegate lowstand sequence set which rests on the Castlegate sequence boundary.

The Grassy highstand sequence set has been deposited during a rise in base level (Van Wagoner, 1995). It comprises a range of coastal plain, lagoonal, foreshore, shoreface and offshore facies. In contrast, both Desert and Castlegate lowstand sequence sets have been deposited in fluvial and coastal-plain depositional environments. They are braided-stream deposits forming fluvial sheet sandstones contained within incised valleys, in response to a drop in base level (Van Wagoner, 1995).

According to the geological interpretation of the Blaze Canyon outcrop from Stewart (1998), two main facies can be identified and subdivided into eight different lithofacies. Their petrophysical properties (porosity and permeability) are also quantitatively determined. The two main facies are the shallow marine facies and the fluvial facies.
4.2.3: The shallow marine facies

In shallow marine environment, the shoreface sediment deposit, which extends from the low water mark to the fairweather wave base, is generally controlled by both wave and current processes (Figure 4.4). The relative influence of these two processes depends upon various factors, including the water depth and the weather. The higher the water level is, the less the effect of the waves. Architecture of shallow marine reservoirs are made of repeated motifs of lamina and bedforms, including trough cross-bedding, swaley cross-lamina, and hummocky cross-stratification. Examples of hummocky cross-stratification features are presented in Figure 4.5. Swaley cross-stratification is a slightly modified type of hummocky cross-stratification, with a pronounced erosion between the sets, leading to erosion of many of the upward-convex laminae in the upper parts of sets (Gardiner, 2000).

![Figure 4.4: Depositional environments and facies model for wave-dominated delta system and shoreface (from Chan et al., 1991).](image-url)
In the case of the Blaze Canyon outcrop, the shallow marine facies is made of:

- upper shoreface sandstone;
- middle shoreface sandstone;
- lower shoreface sandstone;
- shelf shales.

The three types of shallow marine sandstones are uniform, massive and clean. They can extend laterally for distances of several kilometres. The upper shoreface sandstone contains more than 99% of clean sandstone, the middle shoreface sandstone contain more than 98% of clean sandstone, and the lower shoreface sandstone more than 95% of clean sandstone (Arnot, 2000). Sedimentary architecture within these three types of shallow marine shoreface facies are however different. Upper shoreface sandstone has a distinctive white appearance. They display abundant trough cross-bedding and minor low angle or asymptotic cross beds, together with horizontal and wavy lamination (Ciametti, 1994; Couples et al., 1999). The middle shoreface facies is characterised by amalgamated swaley cross-stratification and hummocky cross-stratification (Stewart, 1998). The lower shoreface is made of hummocky cross-stratification which may contain discontinuous shales parting between the hummocs (Ciametti, 1994). Below the
lower shoreface facies are present shelf shales, which form the bottom seal of the reservoir model.

4.2.4: The fluvial facies

The fluvial facies is made of:

- high net to gross channel fill sandstones;
- low net to gross channel fill sandstones;
- interfluvial heterolithic facies including coastal plain shales;
- coal and organic rich shales.

Desert Member and Castlegate Sandstone possess more complex vertical and lateral variability than the shallow marine facies sandstones. The detailed internal architecture of these two types of formation is described by Van Wagoner (1991). At the location of the Blaze Canyon outcrop, the Castlegate Sandstone is a high net to gross channel, and may represent deposition from braided streams. In contrast, the Desert Member is a low net to gross channel, and may represent deposition in a meander belt fluvial system (Van Wagoner, 1995). Interfluvial heterolithics, interpreted to be laterally-accreted point bar deposits, and coastal plain shales are also present, lateral to, and interbedded within the fluvial facies. Sand bodies within these heterolithics are poorly connected (Ciammetti, 1994). Coals and organic rich shales are present within these fluvial lowstand system tracts.
4.3: Dynamic reservoir models

4.3.1: Description

The reservoir section of the Blaze Canyon outcrop is approximately 1250 m long and 70 m high (Figure 4.6). Its geological interpretation, carried out with photopanels of the outcrop has been pixelized and gridded in 2-D models by Stewart (1998) to be used for reservoir flow simulation. Two main types of models have been built in the Eclipse 100 black oil simulator, with different cell sizes: a fine grid model and a coarse grid model. Their characteristics are detailed as follows.

![Figure 4.6: Blaze Canyon outcrop photopanel interpretation (from Stewart, 1998).](image)

The fine grid model has 12524 cells (124 cells wide by 101 cells high) including 8640 active cells. Each cell is 10m wide by 1m high. The coarse grid model has 250 cells (25 cells wide by 10 cells high) including 180 active cells. Each cell is 50m wide by 10m high.
Eight different lithofacies are present in the fine grid model:

- shales (lithofacies 1);
- heterolithics (lithofacies 2);
- Castlegate Sandstone (lithofacies 3);
- Desert Sandstone (lithofacies 4);
- upper shoreface sandstone (lithofacies 5);
- middle shoreface sandstone (lithofacies 6);
- lower shoreface sandstone (lithofacies 7);
- coal (lithofacies 8).

These lithofacies are also present in the coarse grid model, with the exception of the coal, which is modelled as a transmissibility barrier between grid blocks.

Dead oil (density of 0.876 g/cm$^3$, viscosity of 5 cp) and water (density of 1 g/cm$^3$, viscosity of 1 cp) were the two fluid phases incorporated in these framework models by Stewart (1998). They were assumed to be incompressible. Each cell was filled by petrophysical properties corresponding to each of these eight facies. These properties included porosity, absolute permeability (in the horizontal (X-) and vertical (Z-) directions), relative permeability and capillary pressure tables. Porosity, absolute permeability, relative permeability, and capillary pressure were assumed non-stress-dependent. The top of the model was set at a depth of 2445 m, and was assigned an initial pore pressure of 23 MPa. Rock compressibility was set at $4.10^6$ psi$^{-1}$, and the production rate was set at 2.5 m$^3$/day. Connate water saturation level was attained in each cell before production. Two vertical wells were modelled: an injector and a producer. The injection well was at the NW of the section, the production well was at the SE of the section. Completion was performed along the whole vertical section of
the reservoir. Production was carried out by injecting water with maintained pressure support.

Figures 4.7 presents both the fine and the coarse grid models of the Blaze Canyon outcrop with the different lithofacies, and both injection and production wells. Due to the different size of the cells of the models, flow simulation running time was different (around 2.5 hours for the fine grid model, and around 2.5 minutes for the coarse grid model). However, as these two models represent the same reservoir, they should lead to similar production profiles. This has required upscaling of the petrophysical properties, performed by Stewart (1998).

**Figure 4.7:** Lithofacies distribution of the Blaze Canyon outcrop. Comparison between the fine grid model (9074 active cells) and the coarse grid model (180 active cells). Dead cells (shale and coal) are represented in white.
4.3.2: Upscaling methodology

4.3.2.1: Definition

Due to the heterogeneity of oil and gas reservoirs and the development of geostatistical reservoir description tools, generation of fine scale reservoir models made of tens of millions cells are common (Christie, 1996). However, to be able to run multi-phase flow simulation in practice, models made of several million blocks need to be reduced to models with no more than tens of thousands of blocks (Christie et al., 1995). The technique used to bridge the gap between these two different scales and to optimise the algorithm speed is called upscaling (Christie, 1996). Upscaling is the process whereby the very detailed geological model is reduced to a coarser fluid flow simulation model (King et al., 1998). It consists in calculating effective properties appropriate for flow simulation on coarser grid models while preserving the key fine scale features and the detailed geological information, and correcting for numerical dispersion (Barker and Thibeau, 1997; Christie and Clifford, 1997).

Fine scale heterogeneities are due to episodic or periodic fluctuations in the depositional process, and may lead to permeability contrasts and capillary forces associated with small scale lamination which may affect hydrocarbon recovery (Corbett et al., 1992). They therefore must be taken into account if present. In the case of multi-phase flows, these small scale heterogeneity effects (millimetre/centimetre scale) are incorporated into coarser grid models through the use of pseudo functions (Christie et al., 1995). The geopseudo methodology, which follows the approach of Corbett et al. (1992), offers a geologically realistic approach to upscale multi-phase flow properties in porous media. It incorporates the flow structure interaction at the lamina, bed, and formation scales, and therefore geological features into the upscaling process (Figure 4.8).
4.3.2.2: Application to the Blaze Canyon outcrop

In the case of the Blaze Canyon outcrop, Section 4.2 has shown that sedimentary architecture can be very complex (especially in the case of the fluvial facies) and that it varies considerably from lithofacies to lithofacies. The geopseudo methodology has therefore been used in this study to upscale petrophysical properties from the lamina scale to the cell size of both fine and coarse grid models (Stewart, 1998). Upscaling has been carried out lithofacies by lithofacies using a multi-step approach, for lithofacies 3 to 7. The first main step was the upscaling from the lamina scale to an intermediate cell size, capturing the geological heterogeneity. The second main step was the upscaling from the intermediate cell size to the size of the grid blocks of the final reservoir grid models.
4.3.2.2.1: Rock functions at the lamina scale

At the lamina scale, in the case of a two-fluid phase system (water and dead oil), rock functions for sandstones were computed using Equations 4.1 to 4.3 corresponding to a drainage process and assuming all rock were water-wet (Stewart, 1998):

\[ P_c = 3S_e^2 \times \left( \frac{\phi}{K_{abs}} \right)^{\frac{1}{2}}, \]  
\[ k_{rw} = 0.3(S_e)^3, \]  
\[ k_{ro} = 0.85(1 - S_e)^3, \]  

where

\[ S_e = \frac{S_w - S_{wc}}{1 - S_{orw} - S_{wc}}, \]  
\[ S_{wc} = 0.6 - 0.165 \log_{10}(k), \]  
\[ S_{orw} = 0.3, \]

with \( k \) is the absolute permeability (mD), \( S_{wc} \) is the connate water saturation (fraction), \( S_{orw} \) is the residual oil saturation (fraction), \( S_e \) is the effective water saturation (fraction), \( P_c \) is the capillary pressure (bar), \( \phi \) is the porosity (fraction), \( k_{rw} \) is the relative permeability to water, and \( k_{ro} \) is the relative permeability to oil.

4.3.2.2.2: From the lamina scale to the grid block size of the flow simulation models

Upscaling from the lamina scale to the reservoir cell scale was performed on the shallow marine sandstones (upper shoreface, middle shoreface and lower shoreface) and on the fluvial sandstones (high and low net to gross lithofacies). Size of the intermediate grid was 0.5m by 1.5m for the middle and lower shoreface facies and 0.5m by 4m for the fluvial facies. Upper shoreface facies has been directly upscaled to the
cell size of the fine grid model (1m by 10m). This has been done using pseudo functions calculated within previous studies (Ciammetti, 1994; Petrie, 1994). From the intermediate cell size, upscaling of the petrophysical properties has been carried out to the cell size of the fine grid model, and then to the cell size of the coarse grid model. Upscaling technique used in these different steps was Kyte and Berry’s method (Kyte and Berry, 1975). It is a two-phase upscaling technique based on a weighted pressure method, which compensates for numerical dispersion due to the increase of the cell size. Porosity, relative permeability (in the X-and Z-directions), and capillary pressure functions were thus derived step by step for increasing cell size and stocked to be used as input within the Eclipse model for flow simulation.

In all geopseudo models, as a typical practice, two pore volumes of water were injected at the rate of 0.48m/day, within the range where capillary and viscous forces are equilibrated (Stewart, 1998), whereas at the full outcrop scale, the rate of the injection was close to 0.2m/day. However, as a fluid flow velocity variation between 0.2m/day and 0.92m/day did not have any effect on the production profiles of the geopseudo models (Stewart, 1998), it was considered legitimate to use the pseudo functions calculated from the geopseudo models within the full outcrop models. Shales and coal being modelled as dead cells (porosity and absolute permeability values were set at zero), no upscaling was performed on these two lithofacies. Moreover, due to their low porosity and absolute permeability values, no upscaling was performed on the heterolithics. Due to the large size of the cells, and in order to preserve the relative lithofacies proportions, coal has been modelled as a transmissibility barrier in the coarse grid model. Table 4.1 presents both porosity and absolute permeability used for each of the 8 lithofacies for the fine and coarse grid models.
<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Porosity</th>
<th>Horizontal permeability (mD)</th>
<th>Vertical permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale (1)</td>
<td>0.00</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Hetherolithics (2)</td>
<td>0.05</td>
<td>1</td>
<td>0.5</td>
</tr>
<tr>
<td>Castlegate (3)</td>
<td>0.20</td>
<td>1086 (577)</td>
<td>980 (266)</td>
</tr>
<tr>
<td>Desert (4)</td>
<td>0.20</td>
<td>461 (249)</td>
<td>74 (10)</td>
</tr>
<tr>
<td>Upper shoreface (5)</td>
<td>0.20</td>
<td>56</td>
<td>40</td>
</tr>
<tr>
<td>Middle shoreface (6)</td>
<td>0.20</td>
<td>22</td>
<td>19</td>
</tr>
<tr>
<td>Lower shoreface (7)</td>
<td>0.20</td>
<td>23</td>
<td>22</td>
</tr>
<tr>
<td>Coal (8)</td>
<td>0.00</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 4.1: Porosity and absolute permeability values of lithofacies 1 to 8 for the fine grid and coarse grid models. Values in brackets are those used in the coarse grid models in the case of the fluvial facies.

It must be noted that this type of multi-level upscaling procedure, which consists in comparing pseudo-functions obtained after upscaling at the level of a single cell, can lead to accumulated errors. Hewett et al. (1998) have reported a methodology based on an analytical solution that allows correcting the pseudo functions of coarse grid effects.
4.4: Modification of the model set up

Reservoir models for flow simulation (fine and coarse grid models) presented in Section 4.3, built by Stewart (1998), are then used as base-case models of the Blaze Canyon outcrop within this study. From these two initial models, several alterations have been performed to build reservoir models with different characteristics. These modifications concern the nature of the lithofacies, the reservoir depth, the fluid properties, the initial reservoir conditions (before production) and the production scenarios. In this section, these modifications are described and the new models are presented.

4.4.1: Lithofacies

Two additional types of lithofacies are considered, even if they are not part of the Blaze Canyon outcrop in reality. They correspond to the well-cemented sandstone (lithofacies 9) and the unconsolidated sand without any sorting upon the grain size distribution from Lochaline (lithofacies 10). Corresponding porosity and absolute permeability (in both X-and Z-directions), used in both fine and coarse grid models, are those measured in the laboratory at a differential pressure close to 22MPa. These properties are summarised in Table 4.2. No upscaling of the petrophysical properties is performed on these two lithofacies, as they were considered uniform.

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Porosity</th>
<th>Horizontal permeability (mD)</th>
<th>Vertical permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well-cemented sandstone</td>
<td>0.05</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>(lithofacies 9)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unconsolidated sand</td>
<td>0.33</td>
<td>1300</td>
<td>1300</td>
</tr>
<tr>
<td>(lithofacies 10)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4.2: Porosity and absolute permeability values of lithofacies 9 and 10 for the fine and coarse grid models.
From the base-case model (model A) built by Stewart (1998), four models with varying properties are built. This allows estimating the influence of the lithofacies on the time-lapse response. Moreover, fine and coarse grid models are built with and without the continuous coal barrier to estimate the influence of a transmissibility barrier within the flow simulation models. The following is a summary of the various models:

• model A: base-case model, with lithofacies 1 to 8;
• model B: model A with coal removed;
• model BT: model B with a synthetic dip of 11.2 degrees increasing upwards the SE of the section;
• model C: model A with the heterolithics and shallow marine sandstones (lithofacies 2, 5, 6 and 7) replaced by the well-cemented sandstone (lithofacies 9);
• model D: model A with the heterolithics and shallow marine sandstones (lithofacies 2, 5, 6 and 7) replaced by the unconsolidated sand (lithofacies 10).

4.4.2: Reservoir depth and confining pressure

Concerning the reservoir depth, two different cases are considered:

• top reservoir set at 2450m depth;
• top reservoir set at 1950m depth.

This provides respectively an overburden pressure of 56.5MPa in the case of the 2450m-depth model, and of 45MPa in the case of the 1950m-depth model, assuming 100m of water overlying the rock. This is based upon the assumptions of an average density of the overburden rock of 2.26g/cm$^3$ (corresponding to a density increase of 1psi per foot) and an average density of water of 1g/cm$^3$. Within the reservoir itself, the
average density of the rock is set at 2.5g/cm$^3$. In-situ stress field is assumed isotropic in all reservoir models.

4.4.3: Fluids

Water is substituted by brine, dead oil is substituted by live oil, and gas phase is added to simulate reservoir fluids. Brine used in the flow simulation models has a salinity (S) of 50,000ppm and does not contain any dissolved gas. Its density is set at 1.03g/cm$^3$ at ambient condition (temperature of 15.6°C and atmospheric pressure) and its compressibility is set at $3.10^{-6}$psi$^{-1}$. Two types of live oil are used, referred to "live oil 1" and "live oil 2". Live oil 1 has a density ($\rho_o$) of 0.825g/cm$^3$ at ambient condition. Its bubble point pressure is set at 19.1MPa (2770psi), its coefficient of isothermal compressibility ($C_o$) at the bubble point is set at $2.10^{-5}$psi$^{-1}$ using relationships from McCain (1990). Live oil 2 has a density ($\rho_o$) of 0.934g/cm$^3$ at ambient condition. Its bubble point is set at 19.1MPa (2770psi), its coefficient of isothermal compressibility ($C_o$) at the bubble point is set at $1.5.10^{-5}$psi$^{-1}$ using relationships from McCain (1990). These two live oils respectively have an American Petroleum Institute oil gravity (API) number of 40 degrees (live oil 1) and of 20 degrees (live oil 2), the API number being defined as follows (Archer and Wall, 1986):

$$\text{API} = \frac{141.5}{\rho_o} - 131.5.$$  \hspace{1cm} (4.4)

Gas used in the flow simulation models has a specific gravity set at 0.7, gas specific gravity being defined as the ratio of the gas density to the air density at ambient (standard) condition (Batzle and Wang, 1992). Its density is 0.00085g/cm$^3$ at ambient condition. These properties are those of the gas which is either dissolved in the live oil, or which may be initially present in the models as a gas cap, or which is used to be injected in the reservoir.
4.4.4: Initial fluid contacts

Three different cases are considered:

- case 1: the oil-water contact is initially set far below the reservoir, and the oil-gas contact far above the reservoir, to ensure that connate water saturation level is attained in all lithofacies before production;
- case 2: the oil-water contact is initially set far below the reservoir, and the oil-gas contact is set within the reservoir;
- case 3: the oil-gas contact is initially set far above the reservoir, and the oil-water contact is set within the reservoir.

Case 1 is considered for almost all the flow simulation models built in this study. Cases 2 and 3 are only considered for models with a dip (models BT). In the case of an oil-water contact within the reservoir (production by water injection), water is injected below the initial oil-water contact only, whereas in the case of an oil-gas contact within the reservoir (production by gas injection), gas is injected above the initial oil-gas contact only. Moreover, in this last case (case 3), both injection well and production well locations have been reversed: the injection well is situated at the SE of the section, whereas the production well is situated at the NW of the section.
4.4.5: Relative permeability and capillary pressure functions

When gas is present in the flow simulation model, there are three phases in the reservoir. Ideally, three-phase relative permeability and capillary pressure curves should be computed. However, to simplify such a process, the Eclipse programme requires as input, for the flow simulation process to be run, the relative permeability and capillary pressure curves derived independently for an oil-water system on one hand, and for an oil-gas on the other hand. Connate water saturation level is also taken into account when deriving the oil-gas system curves.

4.4.5.1: Oil-water system

Rock functions and pseudo functions were computed by Stewart (1998) in the case of a water and dead oil two-phase system to run the base-case models. In the case of the adapted flow simulation models, water is replaced by brine and dead oil by live oil. However, same rock functions are used, despite the differences of fluid density and viscosity. Moreover, residual oil saturation ($S_{or}$) in the oil-water system is arbitrary reduced from 0.3 to 0.2 (Ahmed, 2000) allowing a larger amount of oil to be swept by water and therefore leading to larger fluid substitution changes. A saturation weight factor is therefore used to transform the relative permeability and capillary pressure curve from a maximum water saturation level of 0.7 to 0.8 at $S_{or}$. Figure 4.9 shows oil and water relative permeability curves of the upper shoreface sandstone versus brine saturation, in the case of the fine grid model.
4.4.5.2: Oil-gas system

In the case of a drainage cycle relative to an oil-gas system, relative permeability to oil ($k_{ro}$) and relative permeability to gas ($k_{rg}$) are expressed at the lamina scale as follows (Honarpour et al., 1986):

- for consolidated sandstone:

\[
k_{ro} = (S^*)^4, \tag{4.5}
\]

\[
k_{rg} = (1-S^*)^2 \times (1-S''), \tag{4.6}
\]

where

\[
S^* = \frac{S_o}{1-S_{wc}},
\]
\[ k_{ro} = (S^*)^3, \]  
\[ k_{rg} = (1 - S^*)^3, \]

where

\[ S^* = \frac{S_o}{1 - S_{wc}}, \]

with \( S_o \) the oil saturation (fraction), and \( S_{wc} \) the connate water saturation (fraction).

Equations 4.5 and 4.6 are used to derive the relative permeabilities of rock in the case of an oil-gas system for the heterolithics, shallow-marine, fluvial and well-cemented sandstones. Equations 4.7 and 4.8 are computed for the unconsolidated sand from Lochaline. These functions are used for both the fine and coarse grid models, as no upscaling is carried out for the oil-gas system.

Figure 4.10 shows oil and gas relative permeability curves of the upper shoreface sandstone (in the case of both fine and coarse grid models) versus gas saturation. Connate water saturation level (oil-water system), and critical gas and residual oil saturation level (oil-gas system) are taken into account to scale the saturation range. The critical gas and residual oil saturation levels in the oil-gas system are set respectively at 4\% and 23\% of the movable fluid volume (Ahmed, 2000). Connate gas saturation level is set at 0. Complete definitions of the connate and residual saturation levels are given in Section 5.4.3.2, where their influence on seismic P-wave velocity is discussed. Critical saturation corresponds to the maximum saturation level of the fluid at which its relative permeability is zero.
Capillary pressure functions for the oil-gas system are derived independently. They are computed for each lithofacies using the capillary pressure functions of an oil-water system. A parameter $\xi$ related to surface tension derived from the empirical water-oil and oil-gas interfacial tensions is introduced and the capillary pressure function of an oil-gas system is obtained as follows (Amyx et al., 1960):

$$P_{\text{cog}} = \frac{\sigma_{og} \cos(\theta_{og})}{\sigma_{wo} \cos(\theta_{wo})} P_{\text{cwo}} = \xi P_{\text{cwo}},$$

(4.9)

with $\sigma_{wo}$ the interfacial tension of water-oil ($10^{-3}$N/m), $\sigma_{og}$ the interfacial tension of oil-gas ($10^{-3}$N/m), $P_{\text{cog}}$ the capillary pressure of the-oil-gas system, and $P_{\text{cwo}}$ the capillary pressure of the oil-water system. A factor $\xi$ of 0.2 is estimated (Gozalpour, 2000).

Figure 4.10: Relative permeability curves versus gas saturation (oil-gas system with connate water saturation level). Case of the upper shoreface sandstone.
4.4.6: PVT properties

Fluids used in the flow simulation models are brine, live oil and gas. Their Pressure-Volume-Temperature (PVT) properties have to be used as input for flow simulation. These properties include:

- the viscosity of brine ($\eta_b$), live oils ($\eta_o$) and gas ($\eta_g$);
- the formation volume factor ($B_o$) of live oils;
- the solution (or dissolved) gas-oil ratio ($R_s$) of live oils;
- the formation volume factor ($B_g$) of gas.

As they are synthetic fluids, their properties are computed in function of pressure ($P$) and temperature ($T$) using empirical relations derived from Standing (1962) and Batzle and Wang (1992).

4.4.6.1: Brine

Brine viscosity $\eta_b$ (cp) is given by the relation as follows (Batzle and Wang, 1992):

$$\eta_b = 0.1 + 0.333S + \left(1.65 + 91.9S^3\right)\exp\left[\frac{0.42(S^{0.89} - 0.17)^{3.045}}{5^{3.1}}\right],$$  \hspace{1cm} (4.10)

with $T$ the temperature ($^\circ$C) and $S$ the salinity, i.e. the weight fraction of sodium chloride ($10^6$ ppm). It appears from Equation 4.10 that the viscosity of the brine is pressure-independent.

4.4.6.2: Live oil

$R_s$ is the solution (or dissolved) gas-oil ratio (ft$^3$/bbl). It is defined as the number of standard cubic feet of gas which will dissolve in one stock tank barrel of oil when both are taken down to the reservoir at the prevailing reservoir pressure and temperature (Dake, 1978). $B_o$ is the oil formation volume factor (bbl/bbl). It is defined as the
volume in barrels occupied in the reservoir, at the prevailing pressure and temperature, by one stock tank barrel of oil plus its dissolved gas (Dake, 1978). Both the standard cubic foot and the stock tank barrel are defined at standard conditions. The expressions of \( R_s \) (ft³/bbl) and \( B_o \) (bbl/bbl) are given by Standing (1962) and McCain (1990):

\[
R_s = G \left( \frac{P}{18} \times \frac{10^{0.0125A}}{10^{0.00091T}} \right)^{1.2048},
\]

\[
B_o = 0.972 + 0.000147 \left( R_s \left( \frac{G}{\rho_o} \right)^{0.5} + 1.25T \right)^{1.175} \text{ for } P \leq P_b,
\]

\[
B_o = B_{ob} \exp\left( C_o (P_b - P) \right) \text{ for } P \geq P_b,
\]

with \( P \) the pressure (psi), \( P_b \) the bubble point pressure (psi), \( T \) the temperature (°F), \( G \) the gravity of the dissolved gas, \( A \) the API number (deg. API), \( \rho_o \) the reference density of the oil (g/cm³), \( B_{ob} \) the formation volume factor of oil at the bubble point (bbl/bbl) and \( C_o \) the coefficient of isothermal compressibility of the oil at pressure above the bubble point pressure (psi⁻¹).

\( R_s \) and \( B_o \) can be converted in metric units by the following relationships:

- \( R_s \) (m³/m³) = \( R_s \) (ft³/bbl) / 5.615;
- \( B_o \) (m³/m³) = \( B_o \) (bbl/bbl).
Oil viscosity $\eta_o$ (cp) is given by (Batzle and Wang, 1992):

$$\eta_o = \eta_i + 0.145P,$$

where

$$I = 10^{18.6 \left[ 0.1 \log_{10}(\eta_i) + \left( \log_{10}(\eta_i)^2 \right) - 0.985 \right]},$$

$$\eta_i = 10 \left( 0.505y (17.8 + T)^{1.163} \right)^{1.163},$$

$$y = 10^{(5.693 - 2.863/\rho_i)}$$

with $P$ the pressure (MPa), $T$ the temperature ($^\circ$C), and $\rho_i$ the density of the live oil (g/cm$^3$), whose expression is given in Section 5.3.2.1.

### 4.4.6.3: Gas

$B_g$ is the gas formation volume factor (bbl/bbl). It is defined as the volume in barrels that one standard cubic foot of gas will occupy as free gas in the reservoir at the prevailing reservoir pressure and temperature (Dake, 1978).

The expression of $B_g$ ($m^3/m^3$) is given by McCain (1990):

$$B_g = \frac{0.194298 z(1.8T + 32 + 460)}{1000 P},$$

where

$$z = \left( 0.03 + 0.00527(3.5 - T_{pr}) \right) P_{pr} + \left( 0.642T_{pr} - 0.007T_{pr}^4 - 0.52 \right) + E,$$

$$E = 0.109 \left( 3.85 - T_{pr} \right)^2 \exp \left[ - 0.45 + 8 \left( \frac{1 - T_{pr}^2}{T_{pr}} \right) \right],$$

with $P$ the pressure (MPa), $T$ the temperature ($^\circ$C) and $z$ the gas compressibility factor (dimensionless).
Gas viscosity $\eta_g$ (cp) is given by the following expression (Batzle and Wang, 1992):

$$
\eta_g = 0.001P_{pr} \eta_l \left[ \frac{1057 - 8.08T_{pr}}{P_{pr}} + \frac{796P_{pr}^{0.5} - 704}{(T_{pr} - 1)^{0.7} (P_{pr} + 1)} - A \right],
$$

where

$$\eta_l = 0.0001 \left[ \frac{T_{pr} (28 + 48G - 5G^2) - 6.47G^{-2} + 35G^{-1} + 1.14G - 15.55}{4.892 - 0.4048G} \right].$$

$$P_{pr} = \frac{P}{4.892 - 0.4048G} \quad \text{(pseudo reduced pressure)},$$

$$T_{pr} = \frac{T}{94.72 + 170.75G} \quad \text{(pseudo reduced temperature)},$$

$$T_a = T + 273.15 \quad \text{(absolute temperature)},$$

$$A = 3.24T_{pr} - 38,$$

with $P$ the pressure (MPa), $T$ the temperature (°C) and $G$ the gas specific gravity (dimensionless).

**4.4.6.4: Application to the Blaze Canyon flow simulation model fluids**

Temperature effects are not considered; the temperature of all reservoir models is assumed to be constant and is set at 100°C (212°F). The initial pore pressure value is set at 35MPa in all models. Figure 4.11 shows the evolution with pressure of the viscosity of the brine ($\eta_b$), live oils 1 and 2 ($\eta_o$) and gas ($\eta_g$) used in the flow simulation models, given their specific properties. Figures 4.12 and 4.13 show respectively the evolution with pressure of the solution gas-oil ratio ($R_o$) and of the oil formation volume factor ($B_o$) of the live oils. Figure 4.14 shows the evolution with pressure of the gas formation volume factor ($B_g$). These figures shows that properties of both live oils evolve in a different way for pressures below or above the bubble point pressure level (19.1MPa). For example, Figure 4.13 illustrates that the oil formation volume factor decreases with pressure for pressure values below the bubble point pressure level, then
increases. This also has an impact on the evolution of the bulk modulus of the live oils with pressure, as discussed in Section 5.3.4.

Figure 4.11: Viscosity of the fluids (brine, live oils and gas) used in the flow simulation models versus pressure.

Figure 4.12: Solution gas-oil ratio of the live oils versus pressure.
4.4.7: Hydrocarbon recovery process

Three different production scenarios are considered:

- water (brine) injection, controlled by the reservoir fluid volume rate target;
- pressure depletion, for which the production parameters are set up similarly to the water injection case, except that the injection well is shut-in;
- gas injection, controlled by the reservoir fluid volume rate target.
For the water injection and the gas injection scenarios, bottom hole pressures of the injection and production wells are respectively set at 100MPa and at 10MPa, whereas the production rate is set in order to get an inter-well fluid velocity near 0.2m/day. Such fluid velocity leads to reservoir fluid volume rate of:

- 2.9m³/day for models A, B and BT;
- 1.45m³/day for model C;
- 4.15m³/day for model D.

For the pressure depletion scenario, the injection well is closed and the bottom hole pressure of the production well is set at 3MPa. The reservoir fluid volume is therefore set at the following rates, so that pore pressure does not go below 3MPa:

- 0.7m³/day for models A, and B;
- 0.35m³/day for model C;
- 1.25m³/day for model D.

In all models, initial pore pressure is set at 35MPa, and reservoir production is set up arbitrarily to last 34 years (this corresponds to the time for two pore volumes of water to be injected in the case of models A and B).

4.4.8: Stress-sensitivity simulation coupling with flow simulation

Reservoir production may lead to changes in pore pressure and therefore to changes in the three dimensional stress state of the field (Jin et al., 2000). These changes of reservoir conditions can affect both rock porosity and permeability values, as laboratory measurements on cores show that these two parameters can be stress-sensitive, depending on the nature of the rock. These dynamic changes of permeability and
porosity have an impact on the fluid saturation distribution within the reservoir, on the reservoir flow and therefore on the reservoir performance (Lorenz, 1999). They may influence both production rates and hydrocarbon recovery volumes, and consequently the modelling of the time-lapse effects, especially for large pressure changes. Moreover, these pore pressure changes might also lead to changes of the stress states of both the overburden and underburden. This may affect their geomechanical and also their elastic properties and might therefore have an impact on both the seismic imaging of the reservoir and its corresponding time-lapse effects. This is especially the case for large pore pressure changes (Olden et al., 2001). These effects can be taken into account within the modelling process by using a stress-sensitive reservoir simulator: rock mechanical simulator coupled with a fluid flow simulator (Smart et al., 1994).

In this present study, these additional matrix effects are not considered: porosity and permeability are assumed to be constant and independent of both differential pressure and confining pressure (i.e. reservoir depth). However, the evolution of elastic parameters with differential pressure measured in the laboratory is taken into account within the reservoir models (Chapter 5).
4.5: Nomenclature of the flow simulation models

Flow simulation model nomenclature is related to the names of the Eclipse files. They are in the form: \( L_1 L_2 N \); \( L_1 \) being one letter, \( L_2 \) being one or two letters, and \( N \) being a number. Their signification is as follows:

- \( L_1 \) can take the letter \( Z \) (fine grid models) or \( Y \) (coarse grid models);
- \( L_2 \) can be A, or B, or BT, or C, or D, depending on the lithofacies distribution type within the model, the presence or absence of coal, and the presence or absence of an additional dip in the model (Table 4.3);
- \( N \) can take any integer value between 1 and 8, depending on the reservoir depth, the production scenario, and the API number of the live oil (Table 4.4).

The following is a summary of all the fine and coarse grid models for flow simulation used in this study:

- \( A_1, A_2, A_3, A_4, A_5, A_7, A_8 \);
- \( B_3, B_4, BT_1, BT_4 \);
- \( C_1, C_3, C_4, C_5, C_7, C_8 \);
- \( D_1, D_3 \) (only fine grid model), \( D_4 \) and \( D_5 \).
<table>
<thead>
<tr>
<th>L2</th>
<th>Lithofacies changes</th>
<th>Coal barrier</th>
<th>Additional dip</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>B</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>BT</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>C</td>
<td>Lithofacies 2, 5, 6 and 7 replaced by lithofacies 9</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>D</td>
<td>Lithofacies 2, 5, 6 and 7 replaced by lithofacies 10</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>

Table 4.3: L_2 terminology (nomenclature of the flow simulation models).

<table>
<thead>
<tr>
<th>N</th>
<th>Top left cell depth (m)</th>
<th>Production scenario</th>
<th>Oil API number</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2450</td>
<td>Water injection</td>
<td>40</td>
</tr>
<tr>
<td>2</td>
<td>2450</td>
<td>Water injection</td>
<td>20</td>
</tr>
<tr>
<td>3</td>
<td>2450</td>
<td>Oil depletion</td>
<td>20</td>
</tr>
<tr>
<td>4</td>
<td>2450</td>
<td>Gas injection</td>
<td>20</td>
</tr>
<tr>
<td>5</td>
<td>1950</td>
<td>Water injection</td>
<td>40</td>
</tr>
<tr>
<td>6</td>
<td>1950</td>
<td>Water injection</td>
<td>20</td>
</tr>
<tr>
<td>7</td>
<td>1950</td>
<td>Oil depletion</td>
<td>20</td>
</tr>
<tr>
<td>8</td>
<td>1950</td>
<td>Gas injection</td>
<td>20</td>
</tr>
</tbody>
</table>

Table 4.4: N terminology (nomenclature of the flow simulation models).
4.6: Results of the flow simulation modelling

Figures 4.15 to 4.20 present fluid saturation sections of the fine grid models in the cases of water injection (Figures 4.15 and 4.16), pressure depletion (Figure 4.17) and gas injection (Figures 4.18 to 4.20) at several time steps of production. They highlight the dependence of the fluid flow patterns on the lithofacies distribution, the hydrocarbon recovery process and the coal transmissibility barrier.

Figures 4.21 to 4.24 show the production profiles of the most representative results of the flow simulation. Figure 4.21 presents production profile curves for both models ZA$_1$ (fine grid model) and YA$_1$ (coarse grid model). It highlights that production profiles are very similar for both fine and coarse grid models, which signifies that the upscaling has been correctly performed. They also show that water injection process leads to an excellent hydrocarbon recovery efficiency (almost 100%). Similar conclusions are drawn for other water injection models C$_1$ and D$_1$ (Figure 4.22).

Figure 4.23 presents production profile curves for both models ZB$_3$ (fine grid model) and YB$_3$ (coarse grid model), simulating hydrocarbon recovery by pressure depletion. Production profiles are still quite similar, but the fit is not as good as it is for hydrocarbon recovery by water injection. This is explained by the fact that upscaling has not been performed in the case of an oil-gas system. Moreover, these figures illustrate that pressure depletion is far less effective than water injection. Similar conclusions are drawn for the hydrocarbon recovery by gas injection. Finally, Figure 4.24 shows that, in the case of gas injection, oil recovery efficiency is increased if gas is injected in a pre-existing gas cap (model ZBT$_4$) by opposition of gas injection in the oil-bearing reservoir layers (model ZA$_4$).
Figure 4.15: Water saturation distribution (model ZA₁).
(a) Before production. (b) After 7 years.

Figure 4.16: Water saturation distribution after 7 years. (a) Model ZC₁.
(b) Model ZD₁.

Figure 4.17: Gas saturation distribution (model ZA₃). (a) After 7 years.
(b) After 34 years.
Figure 4.18: Gas saturation distribution (model ZA₄). (a) After 7 years.
(b) After 34 years.

Figure 4.19: Gas saturation distribution (model ZB₄). (a) After 7 years.
(b) After 34 years.

Figure 4.20: Gas saturation distribution (model ZD₄). (a) After 7 years.
(b) After 34 years.
Figure 4.21: Production profiles for models ZA₁ (fine grid model) and YA₁ (coarse grid model).

Figure 4.22: Production profiles for models ZC₁, ZD₁ (fine grid models) and YC₁, YD₁ (coarse grid models).
To summarise, the most efficient recovery process in these reservoir configurations is water injection. They also correspond to the flow simulation models for which the fit between the production profiles from both the fine and coarse grid models is the best. Even if the fit is not as good as for both pressure depletion and gas injection scenarios, these two hydrocarbon recovery processes are carried out to study, model and compare their time-lapse responses.
This chapter has illustrated the large number of parameters to consider to build flow simulation models for time-lapse analysis. Petrophysical properties of the lithofacies of the models are an association of those of the rocks forming the outcrop and of the core samples collected from the Lochaline mine. Fine and coarse grid 2-D reservoir models, based on the geometry of a real outcrop (the Blaze Canyon outcrop), have been carefully built for flow simulation. Corresponding flow simulations have been run for different production scenarios, after upscaling of petrophysical properties. Production profiles from the coarse grid models approximately track those of the fine grid models. Highest hydrocarbon recovery is obtained in the case of water injection. The results of these flow simulation models can be integrated with the elastic properties measured in the laboratory on the Lochaline samples (loosely consolidated, well-cemented sandstones, and unconsolidated sands) to model the associated elastic time-lapse effects. This is carried out in Chapter 5.
Chapter 5: Time-lapse Response Modelling and Analysis

This chapter focuses on the integration of the rock physics measurements performed in the laboratory (as presented in Chapters 2 and 3) with the 2-D flow simulation models described in Chapter 4 to model time-lapse effects. It first introduces the role of dynamic flow simulation models for time-lapse studies. It then focuses on the elastic modelling of the time-lapse effects on the Blaze Canyon outcrop reservoir analogue. At various time steps of reservoir production, elastic wave velocities, density and elastic impedances are computed within each grid block of the flow simulation models using Gassmann's relations. This is carried out by combining the rock frame elastic properties of each of the lithofacies with the properties of the fluids filling each corresponding grid block (type of fluid, pressure and saturation levels). 2-D sections of reservoir attributes are then created and compared in order to derive the time-lapse response. Amplitude Versus Offset (AVO) P-P reflectivity sections are also computed and compared for incidence angles from 0° to 30° using Shuey's equations (Shuey, 1985). This workflow allows quantifying the influence of the production scenario, the reservoir lithology, the reservoir depth and the type of fluids on the time-lapse response. The effect on P-wave velocity of the fluid saturation distribution at the scale of the grid block of a coarse grid model is also investigated and its uncertainty is quantified.
5.1: Role of flow simulation models for seismic reservoir monitoring

Time-lapse studies require the association of rock physics and flow simulation disciplines, as a comprehensive understanding of the static and dynamic behaviours of the reservoirs are necessary to model time-lapse effects. Reservoir flow simulator principal aim is to model and thus to predict the evolution with time and space of reservoir parameters, such as fluid pressure, fluid saturation, formation volume factors, solution gas-oil ratio for a given hydrocarbon recovery process. For example, in the case of a recovery by pressure depletion, gas can either migrate towards the production wells or towards the top of the reservoir to form a gas cap, or just stay in place. This depends on parameters such as the geological heterogeneity, the rapidity of the drawn down, the magnitude of both the vertical absolute permeability and the relative permeability of the rock to gas (Pennington, 2000). Each of these scenarios leads to a different time-lapse response and can be modelled by reservoir flow simulators.

Combination of rock physics and flow simulation disciplines therefore allows predicting time-lapse response at the scale of the whole reservoir. This also allows comparing results from reservoir flow simulators (fluid saturation and fluid pressure maps) with seismic data at various time steps of production to constrain and update dynamic reservoir models.
5.2: Rock properties

Rock properties of each of the 10 lithofacies used for the different flow simulation models are presented as follows. As Gassmann’s relations are used to derive both P- and S-wave velocities in each grid block of the flow simulation models, input parameters for each lithofacies are:

- the bulk modulus of the mineral making up the rock \( (K_m) \);
- the density of the mineral making up the rock \( (\rho_m) \);
- the bulk and shear moduli of the dry frame \( (K_d \text{ and } \mu_d) \) as a function of effective stress;
- the rock porosity \( (\phi) \).

Numerical values of these parameters for the 10 lithofacies are presented in Table 5.1.

Elastic properties for the fluvial sandstones (lithofacies 3 and 4) and for the shallow marine sandstones (lithofacies 5, 6 and 7) are those of the loosely consolidated sandstone from Lochaline derived from laboratory experiments (Chapters 2 and 3). The small presence of clay estimated in lithofacies 3, 4, 6 and 7 is taken into account in the computation of both the elastic moduli and the density of the rocks from the properties of clean sandstones (Mavko et al., 1998). Elastic properties for the heterolithics (lithofacies 2) are estimated from Han et al. (1986).

As shales (lithofacies 1) and coal (lithofacies 8) are both modelled as dead cells in the Eclipse files, their porosity is set at 0, and the bulk and shear moduli of their rock frame are assumed non stress-sensitive. They are estimated, as well as their mineral bulk modulus and density, from Simmons and Backus (1994) for the shales, and from Harvey (1993) and Leith (1999) for the coal. Identical elastic properties, in the case of shales and coal are taken for both 2450m and 1950m-depth models.
<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Bulk modulus of the rock mineral (GPa)</th>
<th>Density of the rock mineral (kg/m³)</th>
<th>Porosity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale (lithofacies 1)</td>
<td>25.0</td>
<td>2380</td>
<td>0.00</td>
</tr>
<tr>
<td>Hetherolithics (lithofacies 2)</td>
<td>33.0</td>
<td>2570</td>
<td>0.05</td>
</tr>
<tr>
<td>Castlegate (lithofacies 3)</td>
<td>38.1</td>
<td>2648</td>
<td>0.20</td>
</tr>
<tr>
<td>Desert (lithofacies 4)</td>
<td>38.2</td>
<td>2646</td>
<td>0.20</td>
</tr>
<tr>
<td>Upper shoreface (lithofacies 5)</td>
<td>38.0</td>
<td>2650</td>
<td>0.20</td>
</tr>
<tr>
<td>Middle shoreface (lithofacies 6)</td>
<td>38.8</td>
<td>2644</td>
<td>0.20</td>
</tr>
<tr>
<td>Lower shoreface (lithofacies 7)</td>
<td>39.0</td>
<td>2635</td>
<td>0.20</td>
</tr>
<tr>
<td>Coal (lithofacies 8)</td>
<td>19.0</td>
<td>1880</td>
<td>0.00</td>
</tr>
<tr>
<td>Well-cemented sandstone (lithofacies 9)</td>
<td>38.0</td>
<td>2650</td>
<td>0.05</td>
</tr>
<tr>
<td>Unconsolidated sand (lithofacies 10)</td>
<td>38.0</td>
<td>2650</td>
<td>0.33</td>
</tr>
</tbody>
</table>

**Table 5.1:** Bulk modulus and density of the mineral making up the rock, with porosity of the lithofacies of the flow simulation models.

Bulk and shear moduli of the dry frame ($K_d$ and $\mu_d$) for each lithofacies are derived as a function of effective stress using the parameters $A_1$, $A_2$, $B_1$, $B_2$, $D_1$ and $D_2$ of the empirical relationships presented in Section 3.7 (Equation 3.25). Values of these parameters are presented in Table 5.2.
Table 5.2: Parameters of the empirical relationship of the elastic moduli as a function of effective stress, for the rock frame of the lithofacies of the flow simulation models.

<table>
<thead>
<tr>
<th></th>
<th>$A_1$</th>
<th>$B_1$</th>
<th>$D_1$</th>
<th>$A_2$</th>
<th>$B_2$</th>
<th>$D_2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale</td>
<td>16.90</td>
<td>0.00</td>
<td>0.0000</td>
<td>7.40</td>
<td>0.00</td>
<td>0.0000</td>
</tr>
<tr>
<td>(lithofacies 1)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heterolithics</td>
<td>15.21</td>
<td>1.69</td>
<td>0.0049</td>
<td>12.99</td>
<td>3.82</td>
<td>0.0058</td>
</tr>
<tr>
<td>(lithofacies 2)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Castlegate</td>
<td>12.25</td>
<td>9.19</td>
<td>0.0156</td>
<td>14.18</td>
<td>10.29</td>
<td>0.0092</td>
</tr>
<tr>
<td>(lithofacies 3)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Desert</td>
<td>12.28</td>
<td>9.21</td>
<td>0.0152</td>
<td>13.81</td>
<td>10.03</td>
<td>0.0090</td>
</tr>
<tr>
<td>(lithofacies 4)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upper shoreface</td>
<td>12.22</td>
<td>9.16</td>
<td>0.0160</td>
<td>14.54</td>
<td>10.56</td>
<td>0.0094</td>
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<tr>
<td>(lithofacies 5)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Middle shoreface</td>
<td>12.46</td>
<td>9.34</td>
<td>0.0130</td>
<td>11.81</td>
<td>8.58</td>
<td>0.0077</td>
</tr>
<tr>
<td>(lithofacies 6)</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lower shoreface</td>
<td>12.54</td>
<td>9.40</td>
<td>0.0120</td>
<td>10.91</td>
<td>7.92</td>
<td>0.0071</td>
</tr>
<tr>
<td>(lithofacies 7)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>18.89</td>
<td>0.00</td>
<td>0.0000</td>
<td>3.63</td>
<td>0.00</td>
<td>0.0000</td>
</tr>
<tr>
<td>(lithofacies 8)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well-cemented sandstone</td>
<td>32.55</td>
<td>0.70</td>
<td>0.0150</td>
<td>34.97</td>
<td>14.17</td>
<td>0.0120</td>
</tr>
<tr>
<td>(lithofacies 9)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unconsolidated sand</td>
<td>5.11</td>
<td>4.80</td>
<td>0.0013</td>
<td>3.20</td>
<td>2.79</td>
<td>0.0027</td>
</tr>
<tr>
<td>(lithofacies 10)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

5.3: Fluid acoustic properties

Seismic waves are sensitive to density and to elasticity of porous medium. Therefore both density and P-wave velocity of fluids held by reservoir rocks (shear wave does not travel through fluids) affect the seismic signature and therefore the time-lapse response. Their derivation is explained as follows.

Batzle and Wang (1992) have used empirical trends derived from laboratory experiments and thermodynamic laws to establish relationships between both density and P-wave velocity and fluid properties. These fluid properties depend on the reservoir pressure ($P$) and temperature ($T$), and on fluid composition parameters such as:

- the salinity ($S$) of the brine;
the oil gravity number (API), the formation volume factor ($B_o$), the solution gas-oil ratio ($R_s$) and the gravity of the dissolved gas ($G$) of the live oils;

- the specific gravity ($G$) and the compressibility factor ($z$) of the gas.

In this present study, the relations presented as follows are used to compute the properties (density and bulk modulus) of the reservoir fluids at various time steps of the flow simulation process.

### 5.3.1: Brine

#### 5.3.1.1: Density

Brine density $\rho_b$ (g/cm$^3$) is given by:

$$\rho_b = \rho_w + S (0.0668 + 0.44S + A \times 10^{-4}),$$

(5.1)

where

$$\rho_w = 1 + 1 \times 10^{-6} \left( B - 2TP + 0.016T^2P - 1.3 \times 10^{-3}T^3P - 0.002TP^2 \right),$$

$$A = 300P - 2400PS + T(80 + 3T - 3300S - 13P + 47PS),$$

$$B = -80T - 3.3T^2 + 0.00175T^3 + 489P - 0.333P^2,$$

with $P$ the pressure (MPa), $T$ the temperature ($^\circ$C) and $S$ the salinity ($10^4$ ppm).

#### 5.3.1.2: P-wave velocity

Brine P-wave velocity $V_b$ (m/s) is given by:

$$V_b = V_w + SC + S^{1.5} \left( 780 - 10P + 0.16P^2 \right) - 820S^2,$$

(5.2)

where
\[ C = 1170 - 9.6T + 0.055T^2 - 8.5 \times 10^{-5}T^3 + 2.6P - 0.0029TP - 0.0476P^2, \]

\[ V_w = \sum_{i=0}^{4} \sum_{j=0}^{1} w_{ij}T^iP^j \text{ (P-wave velocity of water),} \]

with \( P \) the pressure (MPa) and \( T \) the temperature (°C).

Dimensionless coefficients \( w_{ij} \) are presented in Table 5.3.

| \( w_{00} \) | 1402.85 |
| \( w_{01} \) | 4.871 |
| \( w_{02} \) | -0.04783 |
| \( w_{03} \) | 1.487x10^4 |
| \( w_{04} \) | 2.197x10^7 |
| \( w_{10} \) | 1.524 |
| \( w_{11} \) | -0.0111 |
| \( w_{12} \) | 2.747x10^4 |
| \( w_{20} \) | -6.503x10^7 |
| \( w_{21} \) | 7.987x10^10 |

Table 5.3: Coefficients \( w_{ij} \) for the computation of the P-wave velocity of water (from Batzle and Wang, 1992).

### 5.3.2: Live oil

#### 5.3.2.1: Density

Live oil density \( \rho_{ol} \) (g/cm³) is given by:

\[ \rho_{ol} = \frac{\rho_{pg}}{\left[ 0.972 + 3.81 \times 10^{-4}(T + 17.78)^{1.175} \right]}, \]  

where

\[ \rho_{pg} = \rho_{og} + \left(0.00277P - 1.71 \times 10^{-7}P^3\right)\left(\rho_{og} - 1.15\right)^2 + 3.49 \times 10^{-4}P, \]

\[ \rho_{og} = \frac{\rho_o + 0.0012GR}{B_o}, \]
\[ \rho_o = \frac{141.5}{A + 131.5} \]

with \( P \) the pressure (MPa), \( T \) the temperature (°C), \( A \) the API number (deg. API), \( B_o \) the formation volume factor (m³/m³), \( R_s \) the solution gas-oil ratio (m³/m³) and \( G \) the gas specific gravity (dimensionless).

For dead oil, Equation (5.3) is valid by setting \( \rho_{og} \) at \( \rho_o \).

### 5.3.2.2: P-wave velocity

Live oil P-wave velocity \( V_o \) (m/s) is given by:

\[ V_o = 2096 \left( \frac{\rho^*}{2.6 - \rho^*} \right)^{0.5} - 3.7T + 4.64P + B, \quad (5.4) \]

where

\[ B = 0.0115 \left[ 4.12 \left( 1.08 \rho^{* -1} - 1 \right)^{0.5} - 1 \right] TP, \]

\[ \rho^* = \frac{\rho_o}{B_o} \left( 1 + 0.001R_s \right)^{-1}, \]

\[ \rho_o = \frac{141.5}{A + 131.5}, \]

with \( P \) the pressure (MPa), \( T \) the temperature (°C), \( A \) the API number (deg. API), \( B_o \) the formation volume factor (m³/m³), \( R_s \) the solution gas-oil ratio (m³/m³) and \( G \) the gas specific gravity (dimensionless).

For dead oil, Equation (5.4) is valid by setting \( \rho^* \) at \( \rho_o \).
5.3.3: Gas

5.3.3.1: Density

Gas density $\rho_g$ (g/cm$^3$) is given by:

$$\rho_g \equiv \frac{28.8GP}{zRT_s},$$

where

$$T_s = T + 273.15 \, (\text{absolute temperature}),$$

with $P$ the pressure (MPa), $T$ the temperature (°C), $G$ the gas specific gravity (dimensionless) and $z$ the compressibility factor (dimensionless). $R$ is the universal gas constant (8.31441J/g.mole.°C).

5.3.3.2: Bulk modulus

The adiabatic bulk modulus $K_g$ (MPa) is given by:

$$K_g = \frac{P \gamma_o}{\left(1 - \frac{P_{pr}}{z} \frac{\partial z}{\partial P_{pr}}\right)},$$

where

$$\gamma_o = 0.85 + \frac{5.6}{(P_{pr} + 2)} + \frac{27.1}{(P_{pr} + 3.5)^2} - 8.7 \exp\left[-0.65(P_{pr} + 1)\right],$$

$$z = \left(0.03 + 0.00527(3.5 - T_{pr})\right)P_{pr} + \left(0.642T_{pr} - 0.007T_{pr}^4 - 0.52\right) + E,$$

$$\left(\frac{\partial z}{\partial P_{pr}}\right)_T = 1.2E \left\{ 0.45 + 8 \left(0.56 - \frac{1}{T_{pr}}\right)^2 \frac{P_{pr}^{0.2}}{P_{pr}} \right\} + 0.03 + 0.00527(3.5 - T_{pr})^3,$$

$$E = 0.109(3.85 - T_{pr})^2 \exp\left\{ -0.45 + 8 \left(0.56 - \frac{1}{T_{pr}}\right)^2 \frac{P_{pr}^{1.2}}{P_{pr}} \right\},$$
P_{pr} = \frac{P}{4.892 - 0.4048G} \text{ (pseudoreduced pressure)},

T_{pr} = \frac{T}{94.72 + 170.75G} = \frac{T + 273.15}{94.72 + 170.75G} \text{ (pseudoreduced temperature)},

with P the pressure (MPa), T the temperature (°C), G the gas specific gravity (dimensionless).

5.3.4: Application to the Blaze Canyon outcrop models

Figures 5.1 to 5.3 present the evolution of the density, bulk modulus and P-wave velocity with pressure for the four types of fluids used in the flow simulation models (brine, live oil 1, live oil 2, and gas). Their properties, presented in Section 4.4.3 are as follows:

- salinity S of 50,000ppm for the brine;
- API number of 40 degrees and 20 degrees, for respectively live oil 1 and 2;
- gas specific gravity G of 0.7 for the gas.

The temperature of the reservoir is assumed to be constant and is set at 100°C. These three figures highlight that the density, the bulk modulus and the P-wave velocity of the brine are larger than those of the live oils, which are themselves larger than those of the gas. These figures also show that the properties of the two types of live oils decrease as pressure decreases for pressure values above the bubble point pressure level (19.1MPa). They then increase as pressure decreases due to gas coming out of solution, the oils becoming stiffer as a result of the decrease of their oil formation volume factor. In contrast, the density, the bulk modulus and the P-wave velocity of the brine and the gas decrease as pressure decreases for the whole range of pressure values.
Figure 5.1: Density of the fluids (brine, live oils and gas) used in the flow simulation models versus pressure.

Figure 5.2: Bulk modulus of the fluids (brine, live oils and gas) used in the flow simulation models versus pressure.

Figure 5.3: P-wave velocity of the fluids (brine, live oils and gas) used in the flow simulation models versus pressure.
Moreover, Figure 5.4 illustrates the large contrast between the bulk moduli of the brine and the gas (\(K_p/K_g\) ratio), compared to the contrast between the bulk moduli of the brine and the live oils (\(K_p/K_{o1}\) and \(K_p/K_{o2}\) ratios).

![Figure 5.4: Bulk modulus ratios (\(K_{\text{brine}}/K_{\text{gas}}, K_{\text{brine}}/K_{o1}\) and \(K_{\text{brine}}/K_{o2}\)) versus pressure.](image)

**5.4: Fluid mixture at the sub-seismic scale**

This section focuses on the determination of both the density and the bulk modulus of a fluid mixture at the sub-seismic scale (macroscopic scale). These properties are then incorporated into Gassmann's equations to derive elastic wave velocities of fluid-saturated rocks. The approach is similar to Section 3.2.4.3 that focuses on the same issue at the sample scale (microscopic scale). Differences however exist concerning the determination of the bulk modulus, due to the contrast of wave frequency content between seismic waves (low frequency content) and ultrasonic waves (high frequency content).
5.4.1: Concept and critical size of fluid patches

Section 3.2.4.3 has illustrated the impact of heterogeneous saturation distribution on ultrasonic P-wave velocities at the microscopic scale. This concept of patchy saturation also exists at a larger scale. Fluid saturation can be also heterogeneously distributed at the sub-seismic scale, due to reservoir heterogeneity, gravity and capillary pressure contrasts (White, 1975). For example, Dvorkin and Nur (1998) have reported that clay content variations may have a small effect on the rock frame elastic moduli but can greatly affect permeability and capillary pressure curves, and therefore fluid saturation distribution within reservoirs. This is illustrated by Figure 5.5, which highlights that for an identical capillary pressure level, fluid saturation may vary with rock permeability.

![Figure 5.5: Schematic capillary pressure curves for a low-permeability and a high-permeability rock (from Dvorkin and Nur, 1998).](image)

Patchy saturation at the macroscopic scale influences seismic and well log wave velocities (Knight et al., 1998; Dvorkin and Nur, 1998) in a similar way that patchy saturation at the microscopic scale influences laboratory ultrasonic wave velocities. Acoustic signatures of fluid saturation distribution at the macroscopic scale are also function of the critical diffusion length ($L_c$). However, for seismic data, due to their low wave frequency content (<100Hz) compared to the frequency content of ultrasonic
laboratory data (0.5-1MHz), the size of the critical fluid patch ($L_c$) is larger. It is not of
the order of the millimetre-centimetre as in the case of laboratory ultrasonic waves, but
it can be of the order of the decimetre-metre. Table 5.4 presents such critical fluid patch
sizes, separating the uniform saturation domain from the patchy saturation domain in
the case of the lithofacies of the Blaze Canyon outcrop reservoir models. Values are
computed using Equation 5.7 (Knight et al., 1998), for a seismic wave frequency of
50Hz:

$$L_c = \sqrt{\frac{10kK_f}{fr\eta_f\phi}}.$$  \hspace{1cm} (5.7)

with $k$ the absolute permeability, $K_f$ and $\eta_f$ respectively the bulk modulus and the
viscosity of the most viscous fluid phase, $\phi$ the porosity and $f$ the wave frequency.

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>$L_c$ (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heterolithic</td>
<td>0.2</td>
</tr>
<tr>
<td>(lithofacies 2)</td>
<td></td>
</tr>
<tr>
<td>Castlegate</td>
<td>2.8</td>
</tr>
<tr>
<td>(lithofacies 3)</td>
<td></td>
</tr>
<tr>
<td>Desert</td>
<td>1.7</td>
</tr>
<tr>
<td>(lithofacies 4)</td>
<td></td>
</tr>
<tr>
<td>Upper shoreface</td>
<td>0.7</td>
</tr>
<tr>
<td>(lithofacies 5)</td>
<td></td>
</tr>
<tr>
<td>Middle shoreface</td>
<td>0.5</td>
</tr>
<tr>
<td>(lithofacies 6)</td>
<td></td>
</tr>
<tr>
<td>Lower shoreface</td>
<td>0.5</td>
</tr>
<tr>
<td>(facies 7)</td>
<td></td>
</tr>
<tr>
<td>Well-cemented sandstone</td>
<td>0.4</td>
</tr>
<tr>
<td>(lithofacies 9)</td>
<td></td>
</tr>
<tr>
<td>Unconsolidated sand</td>
<td>2.4</td>
</tr>
<tr>
<td>(lithofacies 10)</td>
<td></td>
</tr>
</tbody>
</table>

Table 5.4: Critical diffusion length values of the lithofacies of the flow
simulation models (seismic frequency).
Moreover, it is important to notice that fluid patches leading to patchy saturation acoustic signature of seismic waves are sub-seismic scale patches. They are larger than \( L_p \), but they are also small enough so that they are not seismically resolvable. Effective medium theory is therefore applicable to derive the elasticity of the corresponding fluid-saturated rocks. Sizes of such patches have therefore to be much smaller than the seismic wavelength, at least 10 times (Knight et al., 1998). As an order of magnitude, typical sizes (d) of these patches are therefore comprised between a thickness close to \( L_p \) (lower value) and 10 meters (upper value), assuming a P-wave velocity of 5000 m/s and a seismic wave frequency centred at 50 Hz.

### 5.4.2: Density

The density \( \rho_r \) of a fluid mixture is independent of the type of saturation distribution (homogeneous or patchy). It is given by the same relation (Equation 3.9) as expressed in the case of the microscopic scale (Section 3.2.4.3.1):

\[
\rho_r = \sum_i S_i \rho_i. \tag{5.8}
\]

### 5.4.3: Bulk modulus

#### 5.4.3.1: Reuss lower and Voigt upper bounds

The bulk modulus \( K_r \) of a fluid mixture to be used as input into Gassmann's equations for fluid substitution depends on the type of saturation distribution (homogeneous or patchy). Patchy saturation distribution always leads to higher (or equal) bulk modulus values than uniform saturation distribution.
In the case of a homogeneous saturation distribution, the harmonic average (Reuss lower bound) is used to compute the bulk modulus of a fluid mixture (Mavko and Mukerji, 1998):

\[ K_r = \frac{1}{\sum \frac{S_i}{K_i}}. \quad (5.9) \]

In the case of a patchy saturation distribution, the arithmetic average (Voigt upper bound) is used to compute the bulk modulus of a fluid mixture (Mavko and Mukerji, 1998):

\[ K_r = \sum S_i K_i. \quad (5.10) \]

Equation 5.10 is based on the assumption that, for low frequency waves, the bulk modulus \( K_r \) of a fluid \( f \) is much smaller than the dry frame modulus \( M_d \) of the rock, as stated by Mavko and Mukerji (1998):

\[ K_r << M_d = K_d + \frac{4}{3} \mu_d. \quad (5.11) \]

This approximation is valid for both loosely consolidated and well-cemented sandstones from Lochaline. It is however not borne out for the unconsolidated sands, and Equation 5.10 is therefore likely to overestimate their fluid-saturated bulk modulus in the case of a patchy saturation distribution (Mavko and Mukerji, 1998).

### 5.4.3.2: Connate and residual saturations

At the macroscopic scale, Equation 5.10 which is used to compute the bulk modulus of a fluid mixture in the case of a patchy saturation distribution has to be slightly modified to take into account both connate and residual saturation levels (Mavko, 1998). Indeed, considering the pore space of a rock filled by two non-miscible fluids, if displacing one
fluid by the other, it is not possible to reduce the saturation of the displaced fluid to zero. This introduces the concept of both connate saturation and residual saturation.

As reservoir rocks were originally filled by water (brine) before hydrocarbon migration, it always remains a small amount of water within reservoir rocks, before production and at any production stage. This amount corresponds to the connate water saturation ($S_{wc}$). In an oil-water system, it also remains a minimal amount of oil when oil is displaced by water. This amount corresponds to the residual oil saturation ($S_{orw}$). Similarly, in an oil-gas system, it remains a connate gas saturation level ($S_{gc}$), generally very small (Ahmed, 2000), when gas is displaced by oil, and a residual oil saturation level ($S_{org}$), when oil is displaced by gas.

There is thus always a mixture of non-miscible fluids at the scale of the pores: saturation distribution is therefore heterogeneous at this scale. However, the heterogeneity of fluid saturation at both connate and residual saturation levels is at the pore scale, scale much smaller than the critical diffusion length for seismic wave frequencies, as illustrated by Table 5.4. Therefore, seismic waves, contrary to ultrasonic waves used on core samples for laboratory experiments, perceive this heterogeneous distribution at the pore scale as uniform. At the macroscopic scale, the correct model to use to compute the bulk modulus of a fluid mixture, at both connate and residual saturation levels, is therefore the iso-stress model. This means that a patchy saturation distribution at the sub-seismic scale never lead to a pure patchy saturation acoustic signature, but consists in a combination of both patchy and uniform distribution signatures. The Voigt upper bound, used to derive the evolution of the bulk modulus of a patchy fluid mixture, has therefore to be adapted to the low frequencies of seismic waves to take into account these connate and residual saturation levels, as stated by Mavko (1998).
5.4.3.3: Adapted Voigt upper bound

The arithmetic average (Voigt upper bound) is thus adapted to the sub-seismic scale, to take into account both connate and residual saturation levels. The bulk modulus of a fluid mixture ($K$), function of the oil saturation ($S_o$) in a patchy saturation case is computed as follows:

$$K_f(S_o) = K_o \left( \frac{S_o^* - S_o}{S_o^* - S_o^-} \right) + K_o^+ \left( \frac{S_o - S_o^-}{S_o^* - S_o^-} \right),$$  \hspace{1cm} (5.12)

where parameters $K_o^-, K_o^+, S_o^-$, and $S_o^+$ is dependent upon the type of fluid system.

5.4.3.3.1: Oil-water system

In an oil-water system, in which both oil and water are movable, parameters $K_o^-, K_o^+, S_o^-$ and $S_o^+$ are interdependent. They are computed as follows:

$$K_o^- = \frac{1}{1 - S_o^- + S_o^- K_o},$$ \hspace{1cm} (5.13a)

$$K_o^+ = \frac{1}{1 - S_o^+ + S_o^+ K_o},$$ \hspace{1cm} (5.13b)

$$S_o^- = S_{ow},$$ \hspace{1cm} (5.13c)

$$S_o^+ = 1 - S_{wc}.$$ \hspace{1cm} (5.13d)

5.4.3.3.2: Oil-gas system

In an oil-gas system, with a level of water connate saturation ($S_{wc}$), in which both oil and gas are movable, parameters $K_o^-, K_o^+, S_o^-, S_o^+, S_g^-$ and $S_g^*$ are also interdependent. They are computed as follows:

$$K_o^- = \frac{1}{S_{wc}^- + S_g^+ + S_o^- K_o},$$ \hspace{1cm} (5.14a)
\[ K_o^+ = \frac{1}{\frac{S_{wc}}{K_w} + \frac{S_g^+}{K_g} + \frac{S_o^+}{K_o}} \quad (5.14b) \]

\[ S_o^- = 1 - S_{wc} - S_g^+ \quad (5.14c) \]

\[ S_o^+ = 1 - S_{wc} - S_g^- \quad (5.14d) \]

\[ S_g^- = (1 - S_{wc}) \times S_{gc} \quad (5.14e) \]

\[ S_g^+ = (1 - S_{wc}) \times (1 - S_{org}) \quad (5.14f) \]

5.4.3.3.3: Examples

Taking into account both connate and residual saturation levels to compute the bulk modulus of a fluid mixture \( (K_r) \) at the sub-seismic scale actually allows reducing the gap between the bounds corresponding to both the uniform and the patchy saturation distribution cases. This is illustrated by the examples as follows, where \( K_r \) is computed as a function of oil saturation \( (S_o) \) using the iso-stress average (Reuss lower bound), the iso-strain average (Voigt upper bound), and the adapted Voigt upper bound. This process is performed for an oil-water system and for an oil-gas system. Bulk moduli of the individual fluids (brine, live oil 2 and gas) are computed using Batzle and Wang's equations for a temperature of 100°C and a pressure of 30MPa. Connate water saturation \( (S_{wc}) \) is set at 0.2. Connate gas saturation \( (S_{gc}) \) is set at 0, in one case, and at 0.02 in another case to evaluate the influence of this parameter on the adapted Voigt upper bound. Residual oil saturation \( (S_{orw}) \) in the oil-water system is set at 0.2 whereas residual oil saturation \( (S_{org}) \) in the oil-gas system is set at 0.23 (23% of the movable fluid volume). Results are presented in Figures 5.6 to 5.10.
Figure 5.6: Bulk modulus of a fluid mixture versus oil saturation (oil-water system). Influence of the connate and residual saturation levels on the patchy distribution bound.

Figure 5.7: Bulk modulus of a fluid mixture versus oil saturation (oil-gas system). Influence of the connate and residual saturation levels on the patchy distribution bound ($S_g C$ is set at 0).

Figure 5.8: Bulk modulus of a fluid mixture versus oil saturation (oil-gas system). Influence of the connate and residual saturation levels on the patchy distribution bound ($S_g C$ is set at 0.02).
These figures show that the connate and residual saturation levels dramatically reduce the uncertainty on the bulk modulus of a fluid mixture when relating it to the fluid saturation level if the fluid saturation distribution is unknown. They also highlight that this reduction of uncertainty is very much dependent on the accuracy of the estimation of the connate and residual saturation levels for both oil-water and oil-gas systems. As these saturation levels vary from rock to rock, they have to be determined case by case from laboratory experiments (such as core flooding) or alternatively estimated from empirical relationships.
5.4.4: Application to the Blaze Canyon outcrop models

From this section and for all the following sections of this thesis, all patchy saturation models at the sub-seismic scale are computed using the adapted Voigt upper bound.

5.4.4.1: Connate and residual saturations

Table 5.5 presents the values of the parameters $S_{wc}$, $S_{gc}$, $S_{orw}$ and $S_{org}$ for the lithofacies used in the reservoir models based on the Blaze Canyon outcrop. Parameters $S_{wc}$ are those used by Stewart (1998) and depend on the nature of the lithofacies. Parameters $S_{gc}$, $S_{orw}$ and $S_{org}$ are estimated from Honarpour et al. (1986) and Ahmed (2000). $S_{gc}$ and $S_{orw}$ are respectively set at 0 and 0.2. $S_{gc}$ is set at 0 in the flow simulation models in which gas is involved (hydrocarbon recovery by pressure depletion or gas injection). $S_{org}$ is set at 0.23, except for lithofacies 2 (heterolithics) and lithofacies 9 (Lochaline well-cemented sandstone) for which $S_{org}$ is set at 0.6 (Bowen, 1999).

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>$S_{wc}$</th>
<th>$S_{gc}$</th>
<th>$S_{orw}$</th>
<th>$S_{org}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heterolithics (2)</td>
<td>0.60</td>
<td>0.00</td>
<td>0.20</td>
<td>0.60</td>
</tr>
<tr>
<td>Castlegate (3)</td>
<td>0.11</td>
<td>0.00</td>
<td>0.20</td>
<td>0.23</td>
</tr>
<tr>
<td>Desert (4)</td>
<td>0.15</td>
<td>0.00</td>
<td>0.20</td>
<td>0.23</td>
</tr>
<tr>
<td>Upper shoreface (5)</td>
<td>0.32</td>
<td>0.00</td>
<td>0.20</td>
<td>0.23</td>
</tr>
<tr>
<td>Middle shoreface (6)</td>
<td>0.38</td>
<td>0.00</td>
<td>0.20</td>
<td>0.23</td>
</tr>
<tr>
<td>Lower shoreface (7)</td>
<td>0.38</td>
<td>0.00</td>
<td>0.20</td>
<td>0.23</td>
</tr>
<tr>
<td>Well-cemented sandstone (9)</td>
<td>0.60</td>
<td>0.00</td>
<td>0.20</td>
<td>0.60</td>
</tr>
<tr>
<td>Unconsolidated sand (10)</td>
<td>0.10</td>
<td>0.00</td>
<td>0.20</td>
<td>0.23</td>
</tr>
</tbody>
</table>

Table 5.5: Connate and residual saturation values of the lithofacies of the flow simulation models.
5.4.4.2: The link between the bulk modulus of a fluid mixture and the size of flow simulator grid blocks

Two main types of flow simulation models have been built to describe the Blaze Canyon outcrop. These models are fine grid and coarse grid models, with different size of grid blocks. Cell dimensions used for the fine grid models are 10m wide by 1m high, whereas they are 50m wide by 10m high for the coarse grid models. According to Table 5.4, fluid saturation distribution is thus likely to be perceived as homogeneous by seismic waves in each grid block forming the fine grid models, associated to lithofacies for which fluid substitution effects are likely to be detected. Therefore, from the output data given by the flow simulator (pressure, water saturation, oil saturation and gas saturation) for each time step and in each single cell of the fine grid model, there is no uncertainty when computing the bulk modulus of the fluid mixture. It is unique and is given by the Reuss lower bound. However, it is not unique within the cells of the coarse grid models. For these models, any possible fluid saturation heterogeneity at a scale smaller than the vertical size of the cell is actually artificially averaged and smoothed at the scale of the grid block. The real saturation distribution pattern inside each cell is therefore unknown. It can be either homogeneous or patchy, and the bulk modulus of the fluid mixture in these coarse cells lies somewhere between both Reuss lower and Voigt upper bounds. By comparing results between these two types of models with different grid block sizes (fine and coarse), it is assessed in Section 5.6, which of these two bounds is the most appropriate to compute the bulk modulus of a fluid mixture in the cells of the coarse grid models. Analysis is carried out for different hydrocarbon recovery processes.
5.5: Results and interpretation

For each fine grid model, 2-D sections of elastic attributes have been computed with artificial random added-noise (±1% of the computed P- and S-wave velocities) before hydrocarbon production and at several production steps. These attributes include P- and S-wave velocities, P- and S- impedances, $V_p/V_s$ ratio, and P-P reflectivity sections (at 0° and 30° of incidence angle). They are then compared for different time steps to estimate and quantify the corresponding time-lapse effects (Kirstetter et al., 2000). The impacts on the time-lapse response of the reservoir production scenario, the reservoir lithofacies, the reservoir depth, the contrast of fluid properties and the coal layer are assessed. The potential of time-lapse AVO to decouple pressure from fluid saturation effects is also illustrated. Uncertainties on the overall time-lapse response due to the uncertainty on the fluid saturation distribution within the cells of the coarse grid models are quantified, and the influence that this latter may have for interpreting time-lapse data is finally estimated.

5.5.1: Lithofacies type and hydrocarbon recovery process

Main results are presented in Figures 5.11 to 5.18. Comparisons of the results from models $Z_A$, $Z_C$, and $Z_D$ (water injection with no major associated pressure changes) show that the largest time-lapse response occurs within the unconsolidated sands. They are negligible in the case of the well-cemented sandstones as their rock frame elastic moduli are much larger and their connate water saturation level is high (0.6). Intermediate changes are occurring within the fluvial and shallow marine sandstones, whose elastic properties and sensitivity to effective stress are those of the loosely consolidated sandstones from Lochaline (Figures 5.11 and 5.12). Similar observations are made in the case of pressure depletion, by comparing results from models $Z_A$, $Z_C$, $Z_D$. 
and ZD₄ (Figures 5.13 to 5.15) and in the case of gas injection, by comparing results from models ZA₄, ZC₄ and ZD₄ (Figures 5.16 to 5.18). This confirms that the weaker the rock, and/or the higher its porosity, the larger the time-lapse response. It is also noticed that the gas cap extends considerably below the coal barrier in the case of model ZD₄ (Figure 5.18) compared to models ZA₄ and ZC₄ (Figures 5.16 and 5.17). This therefore contributes to a larger time-lapse response.

Table 5.6 summarises the main results for the 2450m-depth models. It presents the values of P-impedance changes after 34 years of production computed from the fine grid models (uniform saturation distribution within each grid block).

<table>
<thead>
<tr>
<th></th>
<th>P-impedance changes (%)</th>
<th>P-impedance changes (%)</th>
<th>P-impedance changes (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Water injection (after 34 years)</td>
<td>Gas injection (after 34 years)</td>
<td>Pressure depletion (after 34 years)</td>
</tr>
<tr>
<td>Fluvial sandstones</td>
<td>4.20</td>
<td>-5.50</td>
<td>-3.40</td>
</tr>
<tr>
<td>Shallow marine sandstones</td>
<td>2.60</td>
<td>-5.50</td>
<td>-3.40</td>
</tr>
<tr>
<td>Unconsolidated sand</td>
<td>18.30</td>
<td>-24.00</td>
<td>-10.00</td>
</tr>
<tr>
<td>Well-cemented sandstone</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 5.6: P-impedance changes after 34 years of production (fine grid models).
Figure 5.11: P-impedance changes (model ZA₁). (a) After 7 years. 
(b) After 34 years.

Figure 5.12: P-impedance changes after 7 years. (a) Model ZC₁. 
(b) Model ZD₁.

Figure 5.13: P-impedance changes (model ZA₃). (a) After 7 years. 
(b) After 34 years.
Figure 5.14: P-impedance changes (model ZC₃). (a) After 7 years. (b) After 34 years.

Figure 5.15: P-impedance changes (model ZD₃). (a) After 7 years. (b) After 34 years.

Figure 5.16: P-impedance changes (model ZA₄). (a) After 7 years. (b) After 34 years.
5.5.2: Reservoir depth

This section illustrates both the importance of the understanding of the evolution with effective stress of the elastic moduli of the rock frame, as discussed in Chapters 2 and 3, and the dependence of the time-lapse response on the initial reservoir effective stress value. Pore pressure is identical for both types of models, 1950m-depth models are thus overpressured reservoirs (initial effective stress of 11MPa) compared to the 2450m-depth models (initial effective stress of 22MPa). Figures 5.19 to 5.21 highlight the influence of the reservoir depth on the time-lapse response. P-impedance changes are
indeed larger for the 1950m-depth models than for the 2450m-depth models, for a given hydrocarbon recovery process. This is observed for hydrocarbon recovery by water injection (model ZA₃), pressure depletion (model ZA₇) and gas injection (model ZA₈). Similar results are observed when comparing the $V_p/V_s$ ratio between models ZA₁ and ZA₅ (Figure 5.22). This illustrates that the deeper the reservoir, the smaller the fluid substitution effects and the pressure effects on the time-lapse response.

(a) color scale (%): -1.96 to 6.80

(b) color scale (%): -3.08 to 10.60

Figure 5.19: P-impedance changes after 7 years. (a) Model ZA₁.

(b) Model ZA₅.

(a) color scale (%): -5.19 to 2.10

(b) color scale (%): -1.95 to 8.80

Figure 5.20: P-impedance changes after 34 years. (a) Model ZA₃.

(b) Model ZA₇.
### Figure 5.21: P-impedance changes after 34 years.

(a) Model ZA₄.  
(b) Model ZA₅.

### Figure 5.22: Vᵣ/Vₛ changes after 7 years.

(a) Model ZA₁.  
(b) Model ZA₃.

#### 5.5.3: Fluid properties

Comparing results from models ZA₁ and ZA₂ highlights that the larger the contrast between fluid properties, the larger the time-lapse response. Larger P-impedance changes are indeed occurring in the ZA₁ model than in the ZA₂ model. This is due to the lower bulk modulus (lower API degree) of live oil 1 compared to this of live oil 2 (Figure 5.23). The influence of the oil properties on the time-lapse response is however in these cases less significant than the influence of the reservoir depth reported in Section 5.5.2.
5.5.4: Coal layer

The coal layer acts as a transmissibility barrier. Its influence on the fluid flow is illustrated in the case of hydrocarbon recovery by gas injection. For such a production scenario, the presence of the coal layer within the reservoir leads, in addition to the formation of a gas cap at the top of the reservoir, to the formation of a second gas cap by fluid gravity segregation just below the coal layer (Figure 4.18). This is explained by the fact that the coal barrier is modelled as continuous between both injection and production wells, preventing any fluid to pass up through the barrier. Its absence leads to the formation of a single gas cap only at the top of the reservoir (Figure 4.19). Modelling the coal transmissibility barrier or not therefore leads to different time-lapse responses, as illustrated by Figure 5.24, as the coal layer leads to the formation of a second major reflectivity contrast within the reservoir. This illustrates the importance of the geological modelling on the fluid flow and therefore on the time-lapse response. The analysis presented in this section also applies in the case of reservoir depletion. The coal layer does not have any impact on the time-lapse response when the reservoir production scenario is water injection, as no main fluid segregation due to density contrasts occurs.
Figure 5.24: P-impedance changes after 34 years. (a) Model ZA₄ (with coal layer). (b) Model ZB₄ (without coal layer).

5.5.5: Time-lapse AVO

In the case of hydrocarbon recovery by pressure depletion, major pressure changes occur, in addition to saturation changes. Therefore, the total amount of P-impedance decrease due to the gas coming out of solution is reduced by the increase of rock frame stiffness due to the increase of effective stress. This is illustrated in the case of model ZA₃ (Figure 5.20a). In the case of model ZA₇, pressure effects are larger than saturation effects and the overall P-impedance increase with production (Figure 5.20b). In this case, both the top and bottom of the reservoir are respectively illuminated by effective stress and saturation contrasts with the overburden and underburden (contrasts due to pressure changes being dominant). However, the formation of gas caps within the reservoir leads at their bottom to acoustic contrasts due to fluid saturation contrasts only.

Figures 5.25 and 5.26 present, in the case of model ZA₇, sections of P-P reflectivity differences after 7 years and 34 years, for incidence angles of respectively 0° and 30°. These figures show that the polarity of the time-lapse response at both bottom and top of the reservoir reverses with the angle of incidence. In contrast, the time-lapse
response at the bottom of the gas cap below the coal layer is not dependent on the angle of incidence, and its polarity therefore does not reverse. This highlights the potential use of time-lapse AVO to distinguish pressure effects from saturation effects by comparing P-P reflectivity differences for different angles of incidence.

![Figure 5.25: P-P reflectivity difference at 0° incidence angle (model ZA_7).](image)

(a) After 7 years. (b) After 34 years.

![Figure 5.26: P-P reflectivity difference at 30° incidence angle (model ZA_7).](image)

(a) After 7 years. (b) After 34 years.

5.5.6: Quantification of the fluid saturation distribution uncertainty on the time-lapse response

Coarse grid models, by opposition to the fine grid models, are the flow simulation models for which the fluid saturation distribution within grid blocks is unknown. This
section therefore deals with the coarse grid models only. The uncertainty on the time-lapse response, due to the fluid saturation distribution unknown within grid blocks of the coarse grid models is assessed with the computation of both ratios \( R_1 \) and \( R_2 \) defined as follows:

\[
R_1 = 100 \frac{\Delta K_{sl}}{K_{sh1}},
\]

\[
R_2 = 100 \frac{\Delta K_{sl}}{|\Delta T L_{0\rightarrow1}|},
\]

(5.15a)

(5.15b)

where \( \Delta K_{sl} \) is the difference of fluid-saturated bulk modulus of the rock between the patchy and the uniform saturation cases at time step 1, \( K_{sh1} \) is the fluid-saturated bulk modulus at time step 1 (assuming a uniform saturation distribution), and \( \Delta T L_{0\rightarrow1} \) is the amount of variations of bulk modulus of the rock due to fluid saturation changes only (assuming a uniform saturation) between time steps 0 and 1. These definitions of \( R_1 \) and \( R_2 \) suggest that the higher these two ratios, the higher the uncertainty on the time-lapse response.

Figures 5.27 to 5.28 present reservoir model 2-D sections of ratio \( R_1 \) after 7 years of production. They illustrate that ratio \( R_1 \) is more likely to be high in both cases of pressure depletion and gas injection (up to 2%) than in the case of water injection, for which it is almost negligible. This means that when there is gas in the reservoir, the uncertainty on the saturation distribution might lead to misinterpretation when trying to quantitatively relate the overall time-lapse response to fluid saturation. This is confirmed by Figure 5.29, which presents sections of ratio \( R_2 \) after 7 years of production for both models \( Z A_3 \) and \( Z A_4 \). They highlight that the uncertainty on the saturated bulk modulus due to the saturation distribution unknown is of a similar order of magnitude than the expected time-lapse response. This illustrates the importance of determining which type of saturation distribution is likely to be in the reservoir to quantitatively
derive the time-lapse response from flow simulators, especially in presence of gas. This is the purpose of the analysis presented in Section 5.6.

**Figure 5.27:** Ratio $R_1$ after 7 years. (a) Model ZA$_1$. (b) Model ZA$_4$.

**Figure 5.28:** Ratio $R_1$ (model ZA$_3$). (a) After 7 years. (b) After 34 years.

**Figure 5.29:** Ratio $R_2$ after 7 years. (a) Model ZA$_3$. (b) Model ZA$_4$. 
5.6: Fluid saturation distribution estimation

Section 5.5.6 has highlighted the significant difference of bulk modulus value that may occur between two identical rocks confined under an identical effective stress and filled by identical fluids with an identical overall fluid saturation level but with a different type of saturation distribution. This difference may actually lead to large uncertainty when trying to relate seismic information to fluid saturation from flow simulators, especially when gas is present in the reservoir. This issue does not concern fine grid models but coarse grid models only, as fluid properties (pressure and saturation) are artificially averaged and therefore smoothed within coarse grid blocks, as discussed in Section 5.4.4.2. In this section, it is assessed which type of fluid saturation distribution (uniform or patchy or a combination of both) within the cells of the coarse grid models is likely to model the acoustic signature computed from the corresponding fine grid models. For this analysis, the following process is carried out for several reservoir model cases.

At a given time step, in a given cell of a coarse grid model, fluid pressure and saturation (brine, oil and gas) are combined with the rock frame and mineral properties of the rock forming the cell into Gassmann's equation to compute the bulk modulus of the saturated rock. Two different values are calculated: one assuming a uniform saturation distribution, the other assuming a patchy saturation distribution. They respectively provide the lowest and the highest values of the saturated bulk modulus for a given oil saturation level. By repeating this process at different time steps, a whole range of saturation is covered and both lower and upper bounds of the saturated bulk modulus are computed as a function of oil saturation.

Independently, a similar process is carried out on the fine grid model representing the same reservoir (identical reservoir depth, identical hydrocarbon recovery process). The
cell of the coarse grid model (50m wide by 10m thick) within which the process described above has been performed is spatially represented by 50 cells (10m wide by 1m thick) in the corresponding fine grid model. In each of these 50 cells, for a given time step, oil saturation is given by the flow simulator, and the elastic moduli is calculated by Gassmann's equation, assuming a uniform saturation distribution. From these two sets of values, the averages of oil saturation ($S_o$) and saturated bulk modulus ($K_s$) are then computed at the scale of the coarse grid model, following the approach used by Sengupta and Mavko (1998) described below. The oil saturation ($S_o$) is computed by Equation 5.16 whereas the corresponding bulk modulus ($K_s$) is computed by Equation 5.17 derived from Hill (Hill, 1963):

$$S_o = \frac{\sum_{i} N \phi_i S_{oi}}{\sum_{i} \phi_i},$$

(5.16)

$$K_s = \left[ \sum_{i} \left( \frac{x_i}{K_i + \frac{4}{3} \mu_i} \right) \right]^{-1} - \frac{4}{3} \sum_{i} x_i \mu_i,$$

(5.17)

where $N$ is the number of cells (50), $\phi_i$ is the porosity of the $i^{th}$ cell, $S_{oi}$ is its oil saturation, $x_i$ is its volume fraction, and $K_i$ and $\mu_i$ are respectively its saturated bulk and shear moduli computed by Gassmann's relations.

Equation 5.17, which allows scaling-up of the saturated bulk modulus from the fine grid model cells to the coarse grid model cell is based on the assumption that all the $N$ constituents of the considered medium have the same shear modulus. This assumption is borne out as each of the selected 50 cells of the fine grid model represent the same type of lithofacies. Their dry shear moduli are therefore identical, and Gassmann's relations predict there is no change in the shear modulus between both dry and saturated rocks. As for the coarse grid models, this process is repeated at several time steps to
cover a large range of saturation. The trend of the calculated saturated bulk modulus with oil saturation derived from the fine grid model is then compared to both lower and upper bounds derived from the coarse grid model. This finally allows assessing whether the real fluid saturation distribution of the fine grid model is likely to be acoustically modelled as uniform (lower bound) or as patchy (upper bound) at the scale of a cell of a coarse grid model.

This process is carried out on five different zones of the reservoir models, each zone corresponding to one cell of the coarse grid model and to 50 cells of the fine grid model. Two of these zones are situated just under the coal layer, whereas the three other zones are situated at the top of the reservoir. These zones are chosen as being located in areas likely to generate the largest elastic impedance changes and therefore likely to control the overall time-lapse seismic response. "Zone 1" is made of Desert Sandstone, "zone 2" is made of upper shoreface sandstone (well-cemented sandstone for type C models, unconsolidated for type D models), "zone 3" and "zone 4" are made of Castlegate Sandstone. "Zone 5" is modelled by the Castlegate Sandstone in the case of the coarse grid models. In the case of the fine grid models, zone 5 is modelled by the association of Castlegate Sandstone (90% of the volume) and upper shoreface sandstone (10% of the volume) to ensure an identical covered area than in the coarse grid model case. These two lithofacies (Castlegate Sandstone and upper shoreface sandstone) have different absolute permeability, relative permeability and capillary pressure functions. They therefore have different connate water saturation values, respectively 0.11 and 0.32. However, the assumption of Equation 5.17 is respected, as these two lithofacies have similar dry shear modulus values (Table 5.2). Figures 5.30 shows the position of these 5 zones within the coarse grid reservoir model. Main results are presented as follows for each type of reservoir production scenario (water injection, pressure depletion and gas injection).
5.6.1: Water injection

Injecting water to sweep oil in a water-wet reservoir is defined as a recovery process by imbibition. Figures 5.31 and 5.32a highlight that the evolution of the saturated bulk modulus with oil saturation follows a uniform saturation distribution (Reuss lower bound). This is in agreement with laboratory experiments performed according to an imbibition technique, as illustrated in Section 3.2.4.3.4. This evolution is observed for water sweeping both types of live oils used in the models (live oil 1 and 2) and appears in this case to be independent of the mobility ratio (mobility ratio is defined in Appendix 2). Considering the case of brine displacing oil 1, the mobility ratio is indeed lower than 1 (≈ 0.3) whereas it is larger than 1 (≈ 2) in the case of brine displacing oil 2. This range of different mobility ratio does not influence the type of fluid saturation distribution.
In contrast, Figures 5.32b and 5.33 highlight an evolution of the saturated bulk modulus with oil saturation following a mixed saturation distribution trend. Zones where are noticed such an evolution are situated at the top of the reservoir (zones 3, 4 and 5), whereas uniform distribution are observed within zones situated just under the coal barrier (zones 1 and 2). This illustrates that for a given reservoir, in the case of a displacement by imbibition (water injection), some areas are likely to exhibit a pure uniform saturation distribution but some others are not.

To summarise, results highlight that fluid saturation distribution, in the case of water injection, can be either uniform or mixed, but is never completely patchy. Moreover, as both connate and residual saturations have allowed a significant reduction of the gap between the lower and the upper bounds (as illustrated by Section 5.4.3.3.3), this difference of saturation distribution does not have a large influence on the computation of the saturated bulk modulus. The difference of values between these two cases (uniform and mixed) does not exceed 2%. These statements might be different in the case of water injection in oil-wet or mixed-wet reservoirs.
Figure 5.31: Saturated bulk modulus versus oil saturation. (a) Zone 1, lithofacies 4, model A_1. (b) Zone 1, lithofacies 4, model A_2.

Figure 5.32: Saturated bulk modulus versus oil saturation. (a) Zone 2, lithofacies 10, model D_1. (b) Zone 4, lithofacies 3, model A_2.

Figure 5.33: Saturated bulk modulus versus oil saturation. (a) Zone 5, lithofacies 3, model A_1. (b) Zone 3, lithofacies 3, model C_1.
5.6.2: Pressure depletion

Pressure depletion is a hydrocarbon recovery process that generates first a decrease of oil pressure. Then, if oil pressure reaches the bubble point pressure of the live oil and then keeps on decreasing, gas comes out of solution. This hydrocarbon recovery process is therefore characterised by both pressure and fluid saturation changes. It is thus necessary to decouple preliminary these two effects to study the single effect of the fluid saturation distribution on the saturated bulk modulus. This is illustrated by Figures 5.34 and 5.35.

These figures present the evolution of the saturated bulk modulus as a function of oil saturation in the various zones of interest after scaling-up of the bulk modulus from the cells of the fine grid models for both models ZA3 and ZA7. On these figures are plotted respectively the bulk modulus resulting from both pressure and fluid saturation changes, and the bulk modulus resulting from the fluid saturation changes only. The latter has been obtained by setting constant the pore fluid pressure when calculating the saturated bulk modulus using Gassmann’s relations. Figures 5.34 and 5.35 highlight that pressure effects play a major role on the evolution of the bulk modulus as a function of oil saturation; they might even contribute to hysteresis effects. They add up to the effects of fluid saturation changes, and therefore make difficult to interpret these latter if both pressure and saturation effects are not decoupled.

These figures also illustrate that a decrease of pore pressure leads simultaneously to the two following opposite effects on the saturated bulk modulus. It leads indeed to a decrease of the bulk modulus of the oil for pressure larger than the bubble point pressure, and also to an increase of the rock frame bulk modulus, due to the increase of effective stress. Depending on the relative magnitude of these two pressure effects, the
overall saturated bulk modulus can either increase or decrease. It actually decreases in the case of the 2450m-depth models. This is explained by the fact that the effective stress value before production is large enough that an increase of effective stress due to production only leads to minor increase of the rock frame bulk modulus. The effect of the bulk modulus of the fluid is therefore larger (Figure 5.34). In contrast, in the case of the 1950m-depth models, the increase of effective stress has a larger effect that the decrease of the oil bulk modulus (Figure 5.35). This leads to an overall increase of saturated bulk modulus. These figures shows how critical it is to have a complete understanding of the pressure-sensitivity of the rock frame and to identify the effective stress of the reservoir before production, especially if the hydrocarbon recovery process is likely to lead to large pressure changes.

(a) (b)

**Figure 5.34:** Saturated bulk modulus versus oil saturation. Influence of pressure effects (model A3). Arrows indicate the direction of the trend for the first amount of gas coming out of solution. (a) Zone 3. (b) Zone 5.
Figure 5.35: Saturated bulk modulus versus oil saturation. Influence of pressure effects (model \( A_7 \)). Arrows indicate the direction of the trend for the first amount of gas coming out of solution. (a) Zone 3. (b) Zone 5.

The following results are computed by artificially keeping the pore pressure constant in order to consider only the effect of the fluid saturation on the saturated bulk modulus. By keeping the pore pressure constant when calculating the saturated bulk modulus in both fine and coarse grid models, comparisons are made between the scaled-up bulk modulus from the cells of the fine grid model and both the lower and upper bounds from the corresponding coarse grid model cell. Figures 5.36 and 5.37 illustrate the main results. In all cases, the scaled-up bulk modulus follows a complete uniform saturation evolution for the first amount of gas coming out of solution (about 4% of the total pore volume). These first bubbles of gas thus produce a sharp decrease of the saturated bulk modulus. Then, the evolution separates from the uniform saturation bound for lower oil saturation values and follows a linear trend located between both the lower and upper bounds, with a smaller gradient.
The interpretation of such an evolution is as follows. When the first bubbles of gas come out of solution, gas is not moving, as the relative permeability to the gas is set at zero, for gas saturation levels lower than the critical gas saturation level. Therefore, gas is uniformly distributed within the cells and the evolution of the saturated bulk modulus as a function of oil saturation follows the Reuss lower bound. Then, when gas saturation begins to exceed the critical gas saturation level, gas becomes free to escape and begins to move towards the top and towards the production wells. This is due to fluid gravity segregation, as gas is much lighter than the oil. This interpretation is confirmed when carrying out an identical process after setting artificially the value of the critical gas saturation level at zero in the gas relative permeability curves of the oil-
gas system within the Eclipse files. Results are presented in the case of model ZA3 in Figure 5.38, and highlight that the bulk modulus evolution with oil saturation deviates significantly towards the patchy upper bound for the first amount of gas coming out of solution.

![Diagram showing saturated bulk modulus versus oil saturation](image)

**Figure 5.38**: Saturated bulk modulus versus oil saturation. Influence of the critical gas saturation level (zone 3, lithofacies 3, model A3).
5.6.3: Gas injection

Injecting gas to sweep oil in water-wet reservoirs corresponds to a hydrocarbon recovery process by drainage (Section 3.2.4.3.3). Due to the low viscosity of the gas compared to the viscosity of the oil, the mobility ratio $M$ is higher than in the case of water injection (it is larger than 100).

Main results are presented in Figures 5.39 to 5.41 for the case of gas injection. They illustrate that the evolution of the saturated bulk modulus as a function of oil saturation follows a trend corresponding to a mixed saturation, situated between both the lower and upper bounds. Moreover, the trend does not follow the lower bound for the first bubbles of gas coming out of solution, as it is the case for hydrocarbon recovery by pressure depletion. Saturation distribution is therefore more heterogeneous in the case of gas injection: a small amount of gas leads to a small decrease of saturated bulk modulus compared to the case of pressure depletion. However, these results are not in total agreement with the rock physics experiments performed on core samples in the case of drainage, these latter have exhibited indeed a complete patchy trend (Figure 3.12). This illustrates discrepancies of acoustic signatures of fluid saturation distribution between laboratory and field scales, and consequently the need of modelling studies at the reservoir scale.

Interestingly, zone 5, which is the only zone which possesses an intrinsic degree of heterogeneity (in terms of petrophysical properties only) exhibits the bulk modulus trend the closest to the complete patchy distribution type (Figure 5.41b). This illustrates the impact that small geological heterogeneities have at the sub-seismic scale on the saturation distribution and therefore on the saturated bulk modulus.
Figure 5.39: Saturated bulk modulus versus oil saturation. (a) Zone 3, lithofacies 3, model A. (b) Zone 4, lithofacies 3, model C.

Figure 5.40: Saturated bulk modulus versus oil saturation. (a) Zone 3, lithofacies 3, model BT. (b) Zone 1, lithofacies 4, model BT.

Figure 5.41: Saturated bulk modulus versus oil saturation. (a) Zone 2, lithofacies 10, model D. (b) Zone 5, lithofacies 5, model B.
However, Figure 5.42 highlights two examples for which the trend of the scaled-up bulk modulus of the saturated rock follows the Reuss lower bound. These are the only two examples reported in this study illustrating such a uniform distribution in the case of gas injection. Both examples correspond to zones situated below the coal barrier (zones 1 and 2). Moreover, in these two cases, the zone of study where the saturation is uniformly distributed is represented by the lithofacies with the lowest absolute permeability value among all the lithofacies situated nearby the area of interest. Indeed, zone 2 (unconsolidated sand) in model D4 exhibits a patchy distribution type whereas zone 1 (Desert Sandstone) of the same model exhibits a more uniform distribution type. This is respectively illustrated by Figures 5.41a and 5.42b. Similarly, zone 1 (Desert Sandstone) exhibits a more heterogeneous distribution than zone 2 (upper shoreface sandstone) in model A4, as respectively illustrated by Figures 5.43a and 5.42a. This illustrates the influence of the nature of the nearby rocks on the type of fluid saturation distribution within lithofacies. Similar observations are drawn when comparing results within zone 1 (Desert Sandstone) for models A4, C4 and D4 (respectively Figures 5.43a, 5.43b and 5.42b). In these three models, the recovery process is identical (gas injection), and zone 1 is respectively surrounded by shallow marine loosely consolidated sandstone, well-cemented sandstone (with a lower absolute permeability) and unconsolidated sands (with a higher absolute permeability). These figures illustrate that both the variations of type of saturation distribution and the variations of oil sweeping efficiency in zone 1 depend on the type of lithology of the nearby rocks.

Finally, it is interesting to notice that in the case of gas injection, setting the critical gas saturation level at zero in the relative gas permeability curve of the oil-gas system does not have the same impact as in the case of pressure depletion. It does not lead to any changes of the trend of the saturated bulk modulus as a function of oil saturation towards the upper bound, at low gas saturation levels.
5.6.4: Discussion

It results from the analysis of the type of saturation distribution, in the case of three different hydrocarbon recovery processes carried out in Section 5.6.1 to 5.6.3, that both Reuss lower and adapted Voigt upper bounds act as two extreme bounds. The upper bound is thus never reached by the scaled-up bulk modulus of the saturated rock. The lower bound is reached in some zones when hydrocarbon recovery is carried out by water injection, and in all the zones for the first amount of gas coming out of solution in the case of pressure depletion. However, in most of the cases, and especially for
hydrocarbon recovery by gas injection, these two extreme bounds are never completely reached, and the evolution of the bulk modulus is modelled by a combination of uniform and patchy saturation distributions. This means that the saturation distribution of a mixture of fluids is generally neither totally uniform nor heterogeneous, at the sub-seismic scale.

Moreover, rock wettability has been assumed as water-wet in this study. However, wettability can vary throughout a reservoir and even through a piece of rock, due to mineralogy and surface chemistry heterogeneities (McDougall and Sorbie, 1997; McDougall, 1999). Non-uniform rock wettability at sub-seismic scales might also favour the saturation distribution to be mixed and not totally uniform or patchy. Results also reveal that saturation distribution is dependent on the location within the reservoir: patchy and uniform saturation distributions can co-exist in different areas of a given reservoir. Fluid saturation distribution within a reservoir zone is also dependent on the nature of the nearby rocks, especially in the case of gas injection. This is probably due to permeability contrasts influencing pattern distribution of the fluid flows. Geological heterogeneity at the sub-seismic scale is a source of patchy saturation, as pointed out by Knight et al. (1998) and illustrated by Sengupta et al. (2000). This is illustrated in the case of gas injection by the patchy saturation trend within zone 5, made of two different lithofacies with different petrophysical properties. More work is needed to better understand the causes of this possible uniform saturation distribution in the case of gas injection.

It is finally important to emphasise the importance of both the connate and residual saturation levels at the pore scale that constrain the patchy upper bound. They lead to a significant reduction of the difference of saturated bulk modulus between both uniform and patchy saturation distribution cases. The higher both connate and residual
saturation levels, the closer the lower and upper bounds. However, recent studies have illustrated that residual saturation levels are dependent of a large number factors, including for example the saturation history (Kantzas et al., 2000), or the spreading coefficient in the case of three-phase models (Araujo et al., 2001). These factors therefore also influence the computation of the patchy distribution bound, which thus varies from case to case.

5.7: Conclusions

This chapter has illustrated that time-lapse response is dependent on a large number of parameters. These factors include the elasticity of the rock frame, the reservoir depth, the fluid properties and their contrasts, the hydrocarbon recovery process. It has also revealed the importance to decouple the pressure effects from the saturation effects to interpret the overall time-lapse response in terms of fluid saturation changes. Fluid saturation distribution (uniform or patchy) also controls the time-lapse response. Poor understanding of the distribution of saturation may lead to significant uncertainties when trying to quantitatively relate seismic information to fluid saturation levels derived from the coarse grid models for flow simulation. As noticed in the experiments performed at the laboratory scale (Chapter 3) and as pointed out by Sengupta and Mavko (1998), patchy saturation effects on P-wave velocities are more likely to occur at the reservoir scale in the presence of gas.

However, uncertainty on the saturation distribution does not necessarily prevent quantitatively analysis to be performed, as conclusions concerning the saturation distribution have been drawn in the case of coarse grid models. Figure 5.44 presents a schematic recapitulation of conclusions summarising the main trends of the saturated bulk modulus as a function of fluid saturation for different hydrocarbon recovery
processes. In the case of water injection, the saturation distribution is likely to be uniform or mixed, depending on the location within the reservoir. Both lower and upper bounds are very close, they have a similar evolution with oil saturation. In the case of pressure depletion, the bulk modulus follows the Reuss lower bound until the critical gas saturation is reached and then follows a linear trend towards the residual oil saturation level. Therefore for these two cases, the evolution of the saturated bulk modulus can be predicted and accurately modelled. Using a coarse grid reservoir model does not prevent quantitative analysis of the time-lapse response in terms of fluid saturation changes for these two production scenarios. In the case of gas injection, the type of saturation distribution within cells of a coarse grid model is more difficult to estimate. Its tendency is to follow a linear trend between both lower and upper bounds, but this can vary. This depends on the lithology of the nearby rocks. For this type of recovery process, it seems important to build a fine grid model to capture these fluid heterogeneity distributions in order to relate quantitatively fluid saturation to seismic signature.
Figure 5.44: Schematic of the evolution of the bulk modulus of a saturated rock as a function of saturation (coarse grid model).
Chapter 6: Conclusions and Recommendations for Further Work

This chapter summarises the main conclusions drawn from the areas investigated in the course of this study and suggests recommendations for further work. It is subdivided into two main parts: a section on rock physics, and a section on reservoir modelling for time-lapse analysis. It finally presents a summary of the whole workflow followed in this study to model time-lapse effects.

6.1: Rock physics

Rock physics measurements have been performed on dry and fluid-saturated loosely consolidated, well-cemented sandstones, and unconsolidated sands collected from the same location, namely, Lochaline mine. These measurements have contributed to the laboratory part of a virtual feasibility analysis for a seismic reservoir monitoring study. They allowed generation of a unique data set as grain-to-grain contact areas and porosity were the only petrophysical properties varying among the samples. Three major conclusions have been derived from the analysis of these laboratory data. They are reported as follows.

1. The process of cementation increases the sample stiffness more than the process of consolidation, especially at low effective stress levels. This conclusion results from the combined analyses of the pressure-sensitivity of the compressional and shear wave velocities of the rock frame and of the pressure-sensitivity of the porosity of the samples. Evolution of both bulk and shear moduli with effective stress were
similar in the case of the loosely consolidated sandstone on one hand, and in the case of the unconsolidated sand on the other hand. However, in the case of the well-cemented sandstone, the bulk modulus was constant as a function of effective stress whereas the shear modulus increased exponentially. Both degrees of consolidation and cementation have been quantified in terms of stiffness by introducing the concept of stiffness parameter, based on an effective medium approach. This methodology has been tested on a pure cemented sandstone, the Clashach Sandstone, with an ambient porosity value bounded by those of the loosely consolidated and well-cemented sandstones from Lochaline. Similar values of the stiffness parameter were found for both the Clashach Sandstone and the well-cemented sandstone from Lochaline, illustrating the higher influence on the sample stiffness of cementation compared to this of consolidation.

2. The normalised trends of excess compliance of the unconsolidated sands are less stress dependent than those of both the loosely consolidated and the well-cemented sandstones. This has been illustrated after transformation of both the bulk and shear moduli of the rock frame into normal and tangential excess compliances, after compensation for host matrix softening due to porosity evolution with effective stress. This has highlighted that grains forming the unconsolidated sands are free to slide and rotate into more stable, stiffer configurations when effective stress increases. This statement has been supported by the excellent fit of the experimental data with granular medium theory after calibration based on the assumption of a regular increase of grain-to-grain-contact number with effective stress.

3. The evolution of the compressional velocity at constant pore pressure as a function of saturation follows the Reuss lower bound in the case of fluid injection by imbibition, whereas it follows the Voigt upper bound when drainage is carried out.
This has been tested by injecting water into a dry sample for the imbibition case, and by injecting gas into an oil-saturated sample in the case of drainage. The analysis of the evolution of compressional wave velocity with saturation on partially fluid saturated sandstones has thus allowed estimating the type of fluid distribution within the samples depending on the type of fluid injection, either uniform (modelled by the Reuss lower bound) or patchy (modelled by Voigt upper bound. Fluid substitution effects have moreover been found to be the largest in the case of the unconsolidated sands.

The following items are suggested as possible topics for further work to complete the rock physics part of the study. As the evolution of the closure of grain-to-grain contacts controls the stress-sensitivity of the sample elasticity, it is recommended to carry out S.E.M. analysis on samples under different confining pressure levels in order to visualise and better understand the process of the closure of cracks and contacts with increasing pressure. Moreover, the temperature-sensitivity of the rock frame in these laboratory experiments has not been considered. In the scope of time-lapse analysis, temperature changes can occur. Temperature effects on fluids are generally taken into account but temperature effects on the elasticity of the rock frame are not. This influence would be worth investigation on such a set of core samples with different consolidation and cementation degrees. Finally, it is important to notice that wave attenuation has not been considered within this rock physics study. Derivation of quality factors from waves measured on the set of core samples from Lochaline, for different effective stress and fluid content levels, is then recommended in order attempting to relate them with consolidation and cementation.
6.2: Reservoir modelling for time-lapse analysis

Dynamic reservoir models have been built by integrating both rock physics and flow simulation disciplines for time-lapse response analysis. The building of reservoir models representing the Blaze Canyon outcrop using the elastic properties measured on the Lochaline core samples has allowed assessing the influence of the main parameters and variables to consider for quantitative analysis of time-lapse effects. These parameters include the rock frame properties of the samples, the PVT and acoustic properties of the fluids, the geological description of the model, the type of hydrocarbon recovery process and the size of the grid blocks of the models. Four major conclusions have been derived from the results of the reservoir modelling analysis. They are reported as follows.

1. The parameters with the largest effect on the time-lapse response are the elasticity of the rock frame and its pressure sensitivity. This has been illustrated by the large difference of time-lapse response, which respectively decreases, between the unconsolidated sands, the loosely consolidated and the well-cemented sandstones, and by the decrease of the elastic changes with reservoir depth (i.e. with confining pressure). Results have shown that, for a given production scenario, elastic changes are also affected by the fluid type and fluid properties, but at a least degree. The effects of all these different parameters on the time-lapse response are therefore not of equal importance, but the process of considering each of them contributes to the most accurate prediction of the overall elastic changes.

2. The recovery process corresponding to the most efficient hydrocarbon recovery does not necessarily create the largest time-lapse response. This suggests that improving reservoir hydrocarbon recovery efficiency in a long term scheme does not
compulsorily require a maximum recovery at the early stage of production. It implies it is probably more appropriate to use a production scenario that allows improving and updating the reservoir characterization in the course of production even if this production scenario does not lead to the best hydrocarbon recovery in a short term. This statement might be important to consider for reservoir management.

3. Time-lapse response modelling is strongly influenced by the size of the grid blocks of the flow simulation models, especially when gas is present in the reservoir. This has been illustrated by comparing time-lapse results between models differentiating only from the size of their grid blocks. At the sub-seismic scale, the use of grid blocks with a vertical size larger than the critical diffusion length can thus lead to significant uncertainties as a result of the lack of determination of the fluid saturation distribution within the coarse cells. It has been highlighted that these uncertainties can however be reduced, by taking into account both connate and residual saturation levels in the computation of the upper bound modelling a patchy saturation distribution.

4. Gas injection process requires fine scale modelling whereas water injection and pressure depletion scenarios can be modelled at a coarser scale. This major result has been derived by comparing both the fluid-saturated bulk modulus computed from the fine grid models after appropriate scaling-up to the size of the coarse grid model as a function of oil saturation, and the fluid-saturated bulk modulus directly derived from the coarse grid models. This has been carried out after decoupling pressure effects from saturation effects on the time-lapse response. This approach has allowed determining the type of bound (Reuss or Voigt) modelling the bulk modulus at the scale of the coarse grid cell and also the type of fluid saturation
distribution (uniform or patchy) within the cells of the coarse grid models. It has resulted from this sensitivity analysis that the evolution of the fluid-saturated bulk modulus as a function of oil saturation depends on the nature of the recovery process. In the case of water injection, saturation distribution type at the sub-seismic scale can be represented by either a uniform or a mixed fluid saturation distribution model. However, as both lower and upper bounds are close, both types of saturation distribution lead to similar results. In the case of gas depletion, both lower and upper bounds are distinct, but the saturated bulk modulus evolution is unique. For gas saturation smaller than the critical gas saturation level, the trend fits the lower bound and then is linear towards the residual oil saturation level for gas saturation larger than the critical gas saturation level. In the case of gas injection, the trend is globally linear, below and parallel to the upper bound. It is therefore suggested to take into account these types of saturation distribution when quantifying time-lapse effects by introducing a weight factor relating both the lower and upper bound in the computation of the bulk modulus of a fluid mixture. However, examples of trends of fluid-saturated bulk modulus close to or even fitting the lower bound have also been noticed in the case of gas injection, depending on the location within the reservoir and on the type of lithology of the reservoir rocks. This implies that for a production scenario by gas injection, the linear trend can be a wrong estimation, and that this process, contrary to water injection and pressure depletion scenarios, requires fine scale modelling.

Further work is suggested to complete the reservoir modelling part of the study. It is definitely needed to investigate and determine the causes of the homogeneous saturation distribution, reported in a minority of examples in the case of gas injection. Moreover, results presented in this thesis may also be influenced by the low flow rate used in the model; a sensitivity analysis based on flow rate variations is therefore recommended to
complete the analysis. Independently, it must be pointed out that the results of the time-lapse response have been computed following a purely deterministic approach. However, each of the input parameters is associated with an uncertainty, and therefore the final results are related to a global uncertainty. As the order of magnitude of the time-lapse effects can be small, it is suggested, when comparing results from the modelling with real data, to quantify the global uncertainty of the modelling process in terms of probability. The domain of acoustic and elastic impedances is suggested for such comparison, as it acts as a common domain between the modelling results on one hand, and the seismic data after stratigraphic inversion on the other hand.
6.3: Summary of the workflow for time-lapse prediction

Figure 6.1 summarises the main steps of the workflow proposed in this integrated study to predict time-lapse effects with the specific area investigated in the course of this thesis. Such a workflow is now suggested for application on a real reservoir case.

**Rock Physics**
- Elastic moduli dependence on effective stress and fluid saturation
- Porosity and permeability dependence on effective stress
- Fluid density and bulk modulus dependence on pressure

**Consolidation and cementation**

**Flow simulation**
- Geological description
- PVT properties
- Upscaling of petrophysical properties
- Production scenario
- Pressure and fluid saturation as a function of time

**Grid block size**

**Elastic modelling**
- Gassmann’s relation for fluid substitution
- Scaling-up of the elastic moduli
- Time-lapse response quantification
- Pressure and saturation effects decoupling

**Figure 6.1**: Schematic of the workflow for time-lapse prediction.
References


King, G., 1996. 4-D seismic improves reservoir management decisions, part 2. World Oil, Vol. 217, No. 4, pp. 79-86.


Appendix I: Coefficient of correlation

Considering two series of parameters \((x_i)\) and \((y_i)\), their correlation coefficient \((R)\) linking these two series is defined as follows:

\[
R = \frac{\text{Cov}}{S_x S_y},
\]

where

\[
\text{Cov} = \left(\frac{1}{n} \sum_{i=1}^{n} x_i y_i\right) - \left(\frac{1}{n} \sum_{i=1}^{n} x_i\right) \left(\frac{1}{n} \sum_{i=1}^{n} y_i\right),
\]

\[
S_x = \sqrt{\left[\left(\frac{1}{n} \sum_{i=1}^{n} x_i^2\right) - \left(\frac{1}{n} \sum_{i=1}^{n} x_i\right)^2\right]},
\]

\[
S_y = \sqrt{\left[\left(\frac{1}{n} \sum_{i=1}^{n} y_i^2\right) - \left(\frac{1}{n} \sum_{i=1}^{n} y_i\right)^2\right]}.
\]
Appendix II: Mobility Ratio

The mobility ($\lambda_f$) of a fluid $f$ is defined as the ratio of the rock effective permeability ($k_r$) of the fluid $f$ to its viscosity ($\mu_f$), as stated by Archer and Wall (1986):

$$\lambda_r = \frac{k_r}{\mu_r} = \frac{kk_{rf}}{\mu_r},$$

where $k$ and $k_{rf}$ are respectively the absolute permeability and the relative permeability of the rock to the fluid $f$.

The mobility ratio is defined as the ratio of the mobility of the displacing fluid behind the front to the mobility of the displaced phase ahead of the front (Mian, 1992).

Therefore in the case of water displacing oil, the mobility ratio $M$ is expressed by:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{\left(\frac{k_{rw}}{\mu_w}\right)}{\left(\frac{k_{ro}}{\mu_o}\right)}_{S_{orw}}.$$