Imaging Reservoir Quality of the Triassic-Jurassic succession of Bjarmeland Platform, Norwegian Barents Sea
Examples from Wisting, Norvarg and Ververis discoveries

Manvydas Saltis
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Manvydas Saltis

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Department of Geosciences
Faculty of Mathematics and Natural Sciences

University of Oslo

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This thesis is part of the Trias-North (reconstructing the Triassic northern Barents shelf) project and is submitted to the Department of Geosciences, University of Oslo (UiO), in candidacy of the M.Sc. degree in Petroleum Geology and Petroleum Geophysics.

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Abstract

The Barents Sea is a prospective but challenging area in terms of hydrocarbon exploration. High technical success rate and projected future resources, with around half of Norway’s estimated undiscovered hydrocarbons expected to lie here, are in contrast to the region’s complex geological history. Some of the main concerns in terms of exploration and development are associated with complicated depositional environments, with high lateral facies variations, significant Cenozoic uplift and erosion, and its associated effects on the petroleum systems, dominance of gas discoveries, with a relatively large distance from potential markets, and environmental concerns, among others.

The Triassic (Kobbe and Snadd) and Jurassic (Stø) Formations located on the southern part of the Bjarmeland Platform, in SW Barents Sea are the focus of this study. The Jurassic Stø Formation is known to have good reservoir quality in the SW Barents Sea, but is thin (∼28 m) and not laterally extensive in the study area. The Triassic Kobbe and Snadd Formations are several hundred meters thick, but their reservoir quality is significantly poorer.

The main objective was to characterize reservoir properties within these formations. Geo-physical well logs from 8 exploration wells constitute the main database for the study, which is supplemented by published literature.

Petrophysical analysis shows only thin reservoir intervals are present in the Kobbe Formation (up to 18 m), with poor reservoir properties (shale volume up to 37%, effective porosity up to 16%). However, most of the reservoir intervals within the formation have some amount of gas. The Snadd Formation is found to have numerous reservoir intervals, with intra-Snadd channel sandstone bodies having the largest thicknesses (up to 58 m) and good reservoir properties, albeit with relatively high shale volume (shale volume up to 36%, effective porosity up to 24%). Unfortunately, most of the Snadd Formation reservoirs are brine saturated, and only a few show traces of hydrocarbons. The Stø Formation sandstones are found to have the best reservoir qualities (shale volume up to 26%, effective porosity up to 26%), compared to the other formations. A significant oil accumulation and a significant gas accumulation exist in the Stø Formation in the study area.

Rock physics diagnostics was used to estimate the degree of consolidation. Reservoirs of the Kobbe Formation are found to have 1-5% quartz cement, the Snadd Formation reservoirs are found to have 0-5%, and the Stø Formation reservoirs are found to have 0-2% quartz cement. Correlation with thin section analyses should be done to better constrain the interpretation. $V_p/V_s$ versus AI and Lambda-Mu-Rho plots work well in discriminating lithology and fluid effects, although cementation, relatively high shale volumes and variance in mineralogy are thought to obscure the fluid effects, especially in the deeper reservoirs.

Forward AVO modelling, combined with fluid substitution, showed that hydrocarbon saturation has the effect of producing significant AVO responses, well outside the background trend for most of the reservoirs. The sandstones in most of the reservoirs are found to have lower impedances than the overlying shales. Some of the deeper buried Kobbe reservoirs, however, are probably too consolidated to yield meaningful AVO results.
Abbreviations

AI – acoustic impedance
AVO – amplitude variation with offset
BHT – bottom hole temperature
CC – chemical compaction
frac – fraction
GPa – giga Pascal
GR – gamma ray
g/cc – grams per cubic centimetre
KBSF – kilometres below sea floor
kPa – kilo Pascal
m – meters
MBSF – meters below sea floor
MC – mechanical compaction
MDKB – measured depth from Kelly Bushing
MPa – mega Pascal
ND – neutron-density log combination
RPT – rock physics template
\( I_{GR} \) – gamma ray index
\( S_w \) – water saturation
\( V_p, \) P-wave – compressional wave velocity
\( V_S, \) S-wave – shear wave velocity
\( V_{cl} \) – clay volume
\( V_{sh} \) – shale volume
\( \kappa \) – bulk modulus
\( \lambda \) – incompressibility (in ‘Rock physics diagnostics’)
\( \lambda \) – wavelength (in ‘AVO modelling’)
\( \mu \) – shear modulus
\( \rho \) – density
\( \phi_e \) – effective porosity
\( \phi_t \) – total porosity
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CHAPTER 1

Introduction

1.1. BACKGROUND

The Barents Sea has an area of about 1.3 million km$^2$ and average water depth of about 300 m. It is bordered by the northern Norwegian and Russian coasts to the south, the archipelagos of Novaya Zemlya to the east, Franz Josef Land to the north east, Svalbard to the north west, and the eastern margin of the deep Atlantic Ocean (Doré, 1995).

The United States Geological Survey (USGS) has estimated that about 30% of the world’s undiscovered gas and 13% of the world’s undiscovered oil may be in the Arctic, mostly offshore and under less than 500 meters of water (Gautier et al., 2009).

The first geophysical investigations by the Norwegian authorities in the Barents Sea began in 1969 but were limited to seismic surveys and early NGU (Norwegian Geological Survey) aeromagnetic surveys until the 1980’s. The main offshore sedimentary basins were delineated with the help of reflection seismic data and the first acreage offered to companies in 1980. The first discoveries (the Alke and Askeladden gas fields) were made the following year. Permian, Triassic and Middle Jurassic successions were the main target for exploration (Doré, 1995; Lundschien et al., 2014).

Despite more than 40 years of exploration activities, the knowledge of the Barents Sea geological history, basin evolution and petroleum potential is limited. Exploration in this geographically large area is still considered as being in its early stage and, despite some disappointments, the expectation for petroleum discoveries remains high (Smelror et al., 2009).

Substantial reserves of natural gas have been found in the Barents Sea. As pointed out by Doré (1995), the excitement for finding new discoveries and gaining new economic prospects should be balanced with considerations about the environmental sensitivity of the Arctic area, being one of the few untouched natural wilderness areas on the globe. Sooner or later, however, the depletion of easily accessible reservoirs and a potential interest in gas as a means to achieve lower greenhouse gas emissions should turn the attention to areas such as the Barents Sea for the purpose of meeting global energy needs.
1.2. Motivation

The Lower to Upper Triassic play on the Bjarmeland Platform has been little explored. Out of approximately 10 wildcat wells drilled so far, 3 gas discoveries have been made, with the Norvarg discovery (well 7225/3-1) being the largest. Although a couple of the discoveries were significantly lower than expected, the Norvarg gas discovery and estimates of undiscovered resources is encouraging continued exploration in the Bjarmeland Platform (Halland et al., 2013). A major problem for exploration in the Barents Sea is associated with the complex geology, uplift and erosion effects, which are thought to have led to poor reservoir quality and lack of commercial amounts of hydrocarbons.

Jurassic reservoirs have a much better reservoir quality in the region compared to Triassic, which generally display high shaliness, lower porosities, and high lateral variability. However, Jurassic successions in the study area display very low thicknesses, compared to Triassic, which are, comparatively, much thicker. It is therefore inevitable that, if exploration and development is to continue in the future, a lot of work will have to be done to understand and predict the reservoir properties and the presence of hydrocarbons in these types of reservoir rocks.

This study explores the possibility to characterize Triassic and Jurassic formations of Kobbe, Snadd and Stø using common geophysical techniques and attempts to deal with some of the difficulties associated with the complexities specified above.

1.3. Research objectives

The main objective of this research is to image the reservoir quality of the Triassic and Jurassic Kobbe, Snadd and Stø Formations on the Bjarmeland Platform, Norwegian Barents Sea, with the help of geophysical well log data from 8 exploration wells. Petrophysical analysis, rock physics diagnostics and amplitude variation with offset (AVO) modelling techniques are integrated to study how the various reservoir parameters and geological processes affect the geophysical measurements. The major steps of the workflow are presented below:

- Study the published literature in order to understand the major geologic events that shaped the evolution of the study area, with focus on the three selected Triassic-Jurassic Formations (Kobbe, Snadd and Stø).
- Employ petrophysical analysis to estimate reservoir properties of the formations (lithology, shale volume, porosity, saturation, net-to-gross, among others).
- Use rock physics diagnostics to study the effect of the estimated reservoir parameters on seismic properties (P-, S-wave velocities and density, or any derivatives of these) and to estimate the degree of compaction/cementation.
- Use forward AVO modelling to predict possible AVO signatures and to classify the reservoir sands.
- Discuss the uncertainties and limitations associated with each method used.
1.4. Study area

The study area stretches across the southern part of the Bjarmeland platform, from the Hoop Fault Complex in the western part, to the Norvarg Dome in the central part, and towards the western margin of the Nordkapp Basin in the eastern part (Figure 1.1). Well log data from 8 exploration wells (7324/7-1S, 7324/8-1, 7324/10-1, 7225/3-1, 7225/3-2, 7226/1-1, 7228/2-1S) was used to study reservoir quality of Triassic and Jurassic sandstones. Average water depth in the study area is approximately 400 m.

Figure 1.1: Map of the study area in the Barents Sea showing the main structural elements, studied wells and major discoveries (modified after NPD, 2016). HFC – Hoop Fault Complex; NFC – Nysleppen Fault Complex; MFC – Måsøy Fault Complex; TIFC – Thor Iversen Fault Complex. Red square indicates the study area.
1.5. Database and software

The available data includes well logs from 8 exploration wells. Four wells contained hydrocarbons, namely 7324/8-1 (Wisting oil discovery), 7225/3-1, 7225/3-2 (Norvarg gas discovery and appraisal) and 7226/2-1 (Ververis gas discovery). Three wells had hydrocarbon shows – 7324/7-1S, 7324/10-1, 7228/2-1S, and one well was dry – 7228/1-1. Overview of available well log data is given in Table 1.1.

Table 1.1: Summary of available geophysical well data. Wells are arranged from west (left) to east (right).
Petrophysical analysis was performed using Interactive Petrophysics (Version 4.2.2015.61 (Update 5); Senergy Software Limited). Rock physics diagnostics and forward AVO modelling employed Hampson-Russell Suite (Version 10.0.1; CGG Jason). Finally, well log correlations were done using the Petrel software platform (Version 2015.3; Schlumberger Limited).

1.6. Chapter descriptions

This thesis has been subdivided into 7 different chapters. A summary of each chapter is given below:

Chapter 1 – ‘Introduction’ (this chapter) provides a background for the study. The reader is introduced to the study area, motivation and aims of the research, available data and software packages, and the limitations which can be addressed in future work.

Chapter 2 – ‘Geological setting’ summarizes some of the published literature concerning the geological development of the south-western Barents Sea, with emphasis on the study area and the studied Triassic-Jurassic Formations (Kobbe, Snadd and Stø). Tectonic evolution, depositional systems, uplift and erosion, and its effects on the petroleum systems are addressed.

Chapter 3 – ‘Methodology and theoretical background’ discusses and summarizes the geophysical methods employed during the study. Published theory is supplemented with examples (illustrations and quantitative results) from interpretation of the available geophysical data.

Chapter 4 – ‘Petrophysical analysis’ presents the quantitative results of the petrophysical analysis. Each formations is assessed for its reservoir properties (lithology, shale volume, total end effective porosities, fluid saturation and net-to-gross) and potential reservoir intervals are determined. The estimated reservoir properties and their variation between wells is discussed in terms of the controlling geological processes.

Chapter 5 – ‘Rock physics diagnostics’ links the estimated reservoir properties to their effect on the seismic properties. Various rock physics crossplots ($V_S$ versus $V_P$; $V_P(V_S)$ versus $\phi$; $V_P/V_S$ versus AI; Lambda-Mu-Rho) are used to study the effects of lithology, compaction/cementation, fluids, porosity, among others. Shear wave estimation and the degree of cementation are computed. The results are discussed with reference to the geological development.

Chapter 6 – ‘AVO modelling’ deals with forward AVO modelling. To begin with, some of the commonly chosen parameters (wavelet selection, log blocking and fluid substitution) are discussed and their effect on the AVO modelling studied. Next, AVO forward modelling is performed on selected reservoir intervals within the studied formations. Results are discussed with reference to the petrophysical and rock physics analyses, as well as the geological development.

Chapter 7 – ‘Summary and Conclusions’ summarizes the findings of this study. Results of the three major methods employed in this study (petrophysical analysis, rock physics diagnostics and AVO modelling) are discussed in concert. The findings are compared with several previous studies and suggestions for future work are made.
1.7. Limitations

- Due to time restriction, seismic data, sedimentological analysis and petrographical study of cores and cuttings were not considered in this study.

- The study was restricted to 3 formations of the Triassic-Jurassic successions (Kobbe, Snadd and Stø).

- The data was restricted to well logs from only 8 exploration wells, spread out over a relatively large area (see Figure 1.1).

- S-wave velocity data was not acquired in wells 7324/10-1 and 7228/2-1S, was missing in the Stø Formation in well 7225/3-1, and was only partially available in the Stø Formation in well 7324/7-1S and in the Snadd Formation in well 7225/3-1.

- P-wave velocity was missing over the Stø Formation in well 7225/3-1, and was only partially available over the Stø Formation in well 7324/7-1S, and over the Snadd Formation in well 7225/3-1 (see Appendix B).

- Other types of well log data were missing in some of the wells (see Table 1.1).

- Poor well log data quality resulting from overgauge hole over the Stø Formation in well 7324/7-1S, and over the Kobbe and Snadd Formations in wells 7324/10-1 and 7228/2-1S (see Section 3.2 in the ‘Methodology and theoretical background’ chapter).
CHAPTER 2

Geological setting

2.1. Summary of the regional tectonic and geologic evolution

The distribution of reservoir and source rocks from Late Palaeozoic to Palaeogene in the greater Barents Sea have been related to three major tectonic phases: (i) Caledonian Orogeny causing uplift to the west and distributing sediments across the shelf to the east, towards carbonate platforms; (ii) Uralide orogeny causing uplift to the east and reversing the sediment distribution pattern; and (iii) Late Mesozoic-Cenozoic rifting events (Figure 2.1) and subsequent crustal breakup in the western Barents Sea producing the current basin configuration (Henriksen et al., 2011b).

Figure 2.1: Main structural elements in the Barents Sea. The colours represent major rifting events. Red rectangle indicates the study area (modified from Glørstad-Clark et al., 2010).
The Caledonian orogeny culminated around 400 Ma ago, consolidating the Laurentian (Greenland, North America) and the Baltic plates (Scandinavia, western Russia) into the Laurasian continent and closing the Iapetus ocean, a major seaway, which occupied a similar position to the present northeast Atlantic ocean. The collision between the Laurasian continent and Western Siberia culminated around 240 Ma ago, fusing most of the world’s land into the supercontinent Pangaea. The Uralian mountain chain and and Novaya Zemlya, mark the suture zone of this closure (Doré, 1995).

Extensional tectonic events dominated in the Late Palaeozoic and Mesozoic, firstly due to the collapse of the Caledonian and Uralian mountain belts, and later due to the progressive break-up of the supercontinent Pangaea. These events are recognised in the Early-Middle Devonian, Carboniferous, Permian, Triassic and late Jurassic-Early Cretaceous successions in the Barents Sea, with varying significance depending on specific location. They were responsible for the creation of the major rift basins and the intervening series of platforms and structural highs in the region (Doré, 1995).

Marine depositional environments were the most dominant from the late Palaeozoic to the present day (Heafford, 1988). The depositional environment was strongly influenced by changing climatic factors. Distinct sets of lithologies represent the drift of the Barents shelf northwards during Carboniferous-Triassic from a palaeolatitude of about 20°N to 55°N, and gradually towards its current position of approximately 75°N. Carbonates and evaporites were deposited over large areas in the Devonian, Carboniferous and Permian times, which then changed to clastics from the Triassic times onwards, due to more humid and temperate conditions (Worsley, 1986).

In more recent geological history, since the opening of the Norwegian-Greenland sea around 50 Ma ago, the Barents Sea has been subjected to significant uplift. The mechanisms that caused the initial tectonic uplift are likely related to the mechanisms that caused the opening of the Norwegian-Greenland Sea. Today, huge depositional fans are observed in the western Barents Sea that show large amounts of sediment having been transported to the western and northern margins. Studies have shown that nearly 2/3 of these sediments were deposited during the last 2.3 Ma, which indicates very rapid erosion during this time. The high erosion rates are linked to the glaciation occurring in the Barents Sea during the same period (Dimakis et al., 1998).

2.2. Main structural elements

Roughly, the Barents Shelf can be subdivided into two major geological provinces - Western and Eastern, separated by a monoclinal structure in the centre (Smelror et al., 2009). The largest sedimentary basins are located in the Eastern Barents Sea while the Western Barents Sea is characterised by a much more complex mosaic of platform areas and smaller basins (Figure 2.2). In the following, only the structural elements relevant for this study are discussed. For a regional geologic profile, see Figure 2.3.

2.2.1. Bjarmeland platform

General description. The Bjarmeland Platform is part of an extensive platform area which lies between the Hammerfest and Nordkapp Basins to the south and southeast,
the Sentralbanken and Gardarbanken Highs to the north and the Fingerdjupet Subbasin and Loppa High to the west. All of the wells available in this study, with the exception of 7228/2-1S, lie within the Platform. Minor highs and sub-basins, mostly formed by salt tectonics, form the platform in the southern and western parts. Tertiary uplift has caused the platform sediments to dip gently to the south with progressively older sediments subcropping to the north at base Quaternary unconformity (Gabrielsen et al., 1990; Halland et al., 2013).

A thick Triassic succession of the Early-to-Late Triassic Ingøydjupet Group (Havert,
Klappmyss, Kobbe and Snadd Formations) characterises the Platform, with a largest drilled thickness of 2862 m, while the thickness of the Late Triassic - Middle Jurassic Realgrunnen Group (Fruholmen, Tubåen, Nordmela and Stø Formations) is much more modest – between 100 and 200 m (Halland et al., 2013).

Age. The Platform has been relatively stable since the Late Palaeozoic times (Gabrielsen et al., 1990).

Origin. The Platform was established in the Late Carboniferous and Permian times. Palaeogene tectonism tilted the Paleozoic and Mesozoic sequences towards the south resulting in presently unconsolidated Pleistocene sediments overlying successively older rocks to the north (Gabrielsen et al., 1990; Halland et al., 2013).

2.2.2. Hoop Fault Complex

None of the available wells fall within the Hoop Fault Complex area. However, well 7324/8-1 lies just west of the complex and the associated Wisting oil field is thought to extend into the complex area. The description of the Hoop Fault Complex below is taken from Gabrielsen et al. (1990):

General description. The Hoop Fault Complex is a NE-SW trending lineament which cuts across the Loppa High and the Bjarmeland Platform between 72°50’N, 21°50’E and 74°N, 26°E. It is composed of many normal faults cutting the Bjarmeland Platform in the northern part and a narrow graben on the Loppa High in the southern part.

Age. The complex has been an active zone of weakness since at least the Late Carboniferous, possibly controlling Late Carboniferous to Permian sedimentation patterns in the central part. Reactivations of the zone are recognized in the Middle Triassic, Late Jurassic to Early Cretaceous and possibly Tertiary ages.
CHAPTER 2. GEOLOGICAL SETTING

**Origin.** Subsidence of the Maud Basin in Late Carboniferous to Permian time caused block faulting in the central part. Later reactivations took place along listric faults due to salt movements in the Maud Basin.

2.2.3. Norvarg dome

The Norvarg Dome lies in the central part of the study area and is penetrated by wells 7225/3-1 and 7225/3-2. The description of the Norvarg Dome below is taken from Gabrielsen et al. (1990):

**General description.** The Norvarg Dome is located on the Bjarmeland Platform next to the north-eastern margin of the Swaen Graben. In map view, it is circular to elliptic shape, approximately 25 km across. A lenticular evaporite body is found at the core of the dome and structural closure is defined from Carboniferous to Cretaceous above the evaporites.

**Age.** The evaporite body is thought to be of Carboniferous age and covered by Late Carboniferous to Permian carbonates. Pre-Cretaceous doming is inferred from thinning of the Triassic and Jurassic sequences above the dome. The crest of the dome is truncated by a Quaternary erosional unconformity, hinting to a reactivational event of Late Cretaceous or Tertiary age.

**Origin.** No primary rim synclines are observed and it is unclear how the structure should be interpreted. A possible explanation is that of an anticline located above a salt lens activated by local or regional compression.

2.2.4. Nordkapp basin

The Nordkapp Basin lies in the easternmost part of the study area and its western flank is penetrated by well 7228/2-1 S.

**General description.** The basin is 350 km long, 30-80 km wide and has a general NE-SW trend and a E-W orientation in the central part. The basin margins are defined by the Thor Iversen, Måsøy and Nysleppen Fault Complexes. Numerous major salt structures (walls and diapirs, and salt pillows on the basin margins) are found within the basin, surrounded by flat-lying platforms. The salt in the Nordkapp Basin is of Late Carboniferous to Asselian (earliest Permian) age. The basin was a major site for Triassic deposition (Jensen and Sørensen, 1992; Gabrielsen et al., 1990).

**Age and origin.** Nordkapp Basin was initiated during regional rifting in Late Devonian to Carboniferous and is the most prominent of the Late Palaeozoic rift basins. It has been reactivated during the Late Jurassic to Early Cretaceous and Tertiary times (Jensen and Sørensen, 1992).

2.3. Triassic-Jurassic Stratigraphy and depositional systems

The western Barents Sea region has more or less continuous representations of sedimentary successions from the Upper Palaeozoic through to the Cenozoic (Figure 2.4). However, significant gaps and erosion in stratigraphy is present in some parts of the area (Glørstad-Clark et al., 2010).

The Late Permian - Early Triassic transition is marked by a significant extensional
Figure 2.4: Lithostratigraphy and major tectonic events of the western Barents Sea (from Glørstad-Clark et al., 2010).
event, which triggered the onset of Triassic basin formation in the Western Barents Sea. However, Triassic to Early Jurassic period in the western Barents Sea is considered to have been a tectonically relatively quiet period, associated with passive regional subsidence (Glerstad-Clark et al., 2011).

During the Early Triassic, the Barents Sea was an underfilled epicontinental basin, stretching several hundred kilometres in width. The Stappen and Loppa Highs experienced some tilting and salt tectonics influenced deposition in the Nordkapp and Maud basins, and minor movements occurred on the Bjarmeland and Finnmark platforms during this time. Parts of the Bjarmeland Platform may have been exposed, possibly forming islands with minor local sediment transport systems. After Olenekian, the Western Barents Sea was filled in by prograding deltas, with sediment source areas being in the east to south-east. The organic rich, phosphatic shales of the Botneheia and Steinkobbe Formations represent deposits of the deep shelf area in the west, while the Kobbe and Snadd Formations represent the delta-front area in the east (Smelror et al., 2009; Glerstad-Clark et al., 2011; Gabrielsen et al., 1990).

In Mid-Triassic times, the Barents Sea was made up of a central marine shelf, surrounded by land areas to the northwest, east and south with a probable open marine connection to the North Atlantic rift system in the southwest. Sands sourced from the Urals and the Fennoscandian Shield were deposited in the southwestern shelf area along the NE-SW trending coastline. In the Early to Middle Anisian, northeast trending clinoforms extended to the Bjarmeland Platform. Sands, siltstones and shales of the Kobbe Formation were deposited in delta front to shoreface environments along the coastline (Smelror et al., 2009).

The boundaries of the Middle and Upper Triassic Formations are diachronous (older in the south-east compared with the north-west) due to progressively larger areas being covered by shallow shelf and paralic deposits (Riis et al., 2008). Despite several transgressions, the basin gradually became narrower and was bounded by the paleo-Loppa High to the west and the prograding platform-edges to the east (Glerstad-Clark et al., 2011). During the earliest Late Triassic Carnian times, overall regression took place in the Arctic and is characterised by an extensive westward progradation of coastal depositional environments. The southwestern Barents Sea saw the sedimentation of sandstones with interbedded mudrocks in estuarine to fluvial settings. The sediments form multistorey - multilateral sheets of amalgamated channelised deposits, overlain by Upper Carnian - Lower Norian coal-bearing coastal-plain sediments, interfingering with more marine strata in the west (Smelror et al., 2009).

Sediment sources during the Triassic are thought to primarily be from the Uralian mountains. Thick siliciclastic deposits in both the Norwegian and Russian sectors suggest an orogenic source (Glerstad-Clark et al., 2010). Triassic depositional environments are summarized in Figure 2.5.

During the transition between Late Triassic - Early Jurassic, most of the Barents shelf was uplifted and eroded, resulting in the absence of sedimentary rocks over large parts of the region. The western part of the western Barents Sea was periodically flooded during the Hettangian. Here, sands of the Tubåen Formation, associated
Figure 2.5: Palaeogeographic evolution of the Barents Shelf including Svalbard during the a) Early Triassic, b) Middle Triassic and c) Late Triassic (modified from Lundschen et al., 2014). Red rectangle indicates study area.
with tidal inlets, estuaries and lagoons, were deposited. The northwest prograding Tubåen Formation interfingers with marine shales towards the west and northwest (Glørstad-Clark et al., 2010). More humid conditions in the latest Triassic and Jurassic may have caused a higher production of organic material and thus the amount of organic acids. The presence of smectite in the Upper Triassic deposits is thought to indicate a transitional phase between semiarid and semihumid conditions (Bergan and Knarud, 1992).

During the Toarcian (latest Early Jurassic), eustatic sea level rise resulted in the creation of shallow marine conditions in the western and eastern parts of the Barents Sea. In the southwestern Barents Sea, depositional environments changed from floodplain to prograding coastal settings. Stacked shoreface deposits of the Stø Formation were deposited. The formation consists of sandstones, siltstones and minor shale, and displays very good reservoir qualities in most of the areas where it has been drilled (Smelror et al., 2009).

During the Bajocian (Middle Jurassic), a significant drop in sea level again exposed large areas of the western Barents Sea, resulting in a depositional gap. Shallow marine sandstones of the Stø Formation are found in the Nordkapp and Hammerfest Basins (Smelror et al., 2009).

During the Tithonian (latest Late Jurassic), sea level rise resulted in the flooding of most of the Barents Shelf, with water depths of around 200-300 m over large areas. Barriers and basins created by the Cimmerian tectonic movements allowed for dysaerobic to anoxic conditions to exist. This, combined with low sedimentation rates and high organic productivity, led to significant accumulations of organic matter in the sediments. In the western and northwestern parts of the Barents Shelf, black shales of the Hekkingen Formation were deposited. The formation is now one of the most prolific and important source rocks in the western Barents Sea (Smelror et al., 2009).

The Triassic-Jurassic lithology in the western Barents Sea consists of the Sassendalen, Kapp Toscana groups and of the Fuglen and Hekkingen Formations of the Adventdalen group. The lithology, geophysical well log response and depositional environment of each formation has been summarized by Dalland et al. (1988) and are briefly listed here:

2.3.1. Sassendalen Group

2.3.1.1. Havert Formation

**Age.** The Havert Formation is of Griesbachian to Dienerian age (approx. 251-249.7 Ma).

**Lithology.** The formation consists of medium to dark grey shales with minor interbedded pale grey siltstones and sandstones, which comprise two generally coarsening upwards sequences. Elsewhere, the unit is a more continuous silty shale, with a very weak upwards coarsening trend. Core photographs of the Havert Formation are shown in Figure 2.6.

**Well log response.** The base is defined by increasing gamma ray and decreasing density log responses. The unit overlies a limestone bed and is therefore easily
recognisable.

Depositional environments. The formation has been interpreted to have been deposited in marginal to open marine environments and coastal environments to the south and southeast.

![Figure 2.6: Core photographs of the Havert Formation (4189-4194 m MDKB – left; 4194-4198 m MDKB – right) from well 7228/2-1S (from NPD, 2016).](image)

2.3.1.2. Klappmyss Formation

Age. The Klappmyss Formation is of Smithian to Spathian age (approx. 249.7-245 Ma).

Lithology. The formation consists of medium to dark grey shales, passing upwards into interbedded shales, siltstones and sandstones.

Well log response. The base is defined by an increase in gamma ray, interval transit time and neutron porosity readings. The base represents a sequence boundary caused by an Early Smithian transgressive pulse.

Depositional environments. The formation was deposited in marginal to open marine environments, with renewed northwards coastal progradation following the mentioned Early Smithian transgression.

2.3.1.3. Kobbe Formation

Age. The Kobbe Formation is of Anisian age (approx. 245-237 Ma).
Lithology. The formation consists of a shale unit passing up into interbedded shale, siltstone and carbonate cemented sandstone.

Well log response. Upwards increasing gamma ray, interval transit time and neutron porosity responses are seen in the lower shale unit and are much more varied above.

Depositional environments. The base of the unit marks a transgressive pulse, which is followed by a build-out of clastic marginal marine regimes from southern coastal areas.

![Figure 2.7: Core photographs of the Kobbe (1777-1782 m MDKB) and Snadd (1411-1414 m MDKB) Formations from well 7324/10-1 (from NPD, 2016).]

The Kobbe Formation is special in that the first field to produce oil in the Barents Sea – the Goliat field – consists of two separate siliciclastic reservoirs, one of which is in the Kobbe Formation. The other reservoir is located within the Middle Jurassic Realgrunnen Subgroup (the Kapp Toscana Group). Both reservoirs contain oil with an overlaying gas cap (Arrigoni, 2015). Core photographs of the Kobbe Formation are shown in Figure 2.7.

2.3.2. Kapp Toscana Group

2.3.2.1. Snadd Formation

The Snadd Formation is of Middle Triassic Ladinian to Late Triassic early Norian age. The formation is widely distributed across the Barents Shelf, with common thicknesses in excess of 1000-1200 m. It was deposited during one of the later stages of Early Mesozoic infilling of the Barents Sea Basin. The sediments were expressed as a siliciclastic wedge, prograding from the southeast, where they were shed from the Uralide Orogeny (Klausen et al., 2015; Ryseth, 2014).
The formation was deposited in a shallow basin (100 - 500 m), with the progradation reaching its peak at the Svalbard Archipelago where time equivalent Botneheia and De Geerdalen formations are exposed. The sequence is interpreted to represent depositional environments ranging from offshore shale through shallow marine to fluvial, arranged in discrete stratigraphic sequences. The lithology has been described as grey shales, coarsening upwards into shales interbedded with siltstones and sandstones; interbedding by limestones and calcareous units in the lower and middle parts and thin coal lenses in the upper parts of the unit are described (Klausen et al., 2015; Dalland et al., 1988).

The depositional elements of the Snadd Formation vary both spatially and temporally in relation to the sediment source province and the position of the shoreline. The formation is defined by characteristically thick and widespread river deposits with a significant reservoir potential, while their marine equivalent is characterized by shallow marine beach ridge sets, shelf edge clinoforms and distal marine mudstone, which has source rock potential. During the units deposition, the Barents Sea was located at approximately 44°–49° paleolatitude. A shift from arid to humid climate took place in the study area during the Carnian (~ 237-227 Ma). The Snadd Formation is capped by a regional flooding event, which marks the onset of the Fruholmen Formation (Klausen et al., 2015).

Core photographs of the Snadd Formation are shown in Figure 2.7.

2.3.2.2. Fruholmen Formation

Age. The base of the Fruholmen Formation is Early Norian, while the top, in general, represents the Triassic-Jurassic transition.

Lithology. The formation consists of grey to dark grey shales passing upwards into interbedded sandstones, shales and coals. It is subdivided into three members: Akkar, Reke and Krabbe.

Well log response. The base of Akkar is defined by a significant increase in gamma ray and neutron porosity logs and moderate increases in interval transit time and bulk density logs. The Rekke member has a lower gamma ray signature. At the base of Reke there is a significant decrease in the separation between density and porosity logs, which increases again at the base of the Krabbe Member. Reke and Krabbe Members are characterised by funnel-shaped gamma ray responses.

Depositional environments. The Akkar Member consists of open marine shales, passing into coastal and fluvial sandstone dominated sequences of the Reke Member. The Reke Member is thought to represent northward prograding fluviodeltaic sediments with a depocentre to the south. The central and southern parts of the basin saw mostly flood-plain deposition as the main deltaic sedimentation shifted laterally, while the northern part experienced more marine environments.

2.3.2.3. Tubåen Formation

Age. The Tubåen Formation is Late Rhaetian to Early Hettangian age.

Lithology. The formation is dominated by sandstones with some shales and minor coal deposits, which are most common near the southeastern basinal margins and discontinue in the northwest. The upper and lower sand rich units are separated by a
more shaly interval.

*Well log response.* The base is defined by blocky to bell shaped patterns of the gamma ray log, which is in contrast to the irregular high responses on the underlying unit. A change in separation pattern between the neutron porosity and bulk density is observed.

*Depositional environments.* The Formation has been deposited in high energy marginal marine conditions. To the northwest, shales show a more distal marine environment, while in the southeast the coals and shales were deposited in protected back-barrier lagoonal environments.

Core photographs of the Tubåen Formation are shown in Figure 2.8.

![Core photographs of the Tubåen and Stø Formations from well 7228/2-1S (from NPD, 2016).](image)

**Figure 2.8:** Core photographs of the Tubåen (1384-1387 m MDKB) and Stø (1286-1291 m MDKB) Formations from well 7228/2-1S (from NPD, 2016).

### 2.3.2.4. Nordmela Formation

*Age.* The Nordmela Formation is of Sinemurian to the Late Pliensbachian age. Its top may be diachronous, younging eastwards into the Toarcian.

*Lithology.* The formation consists of interbedded siltstones, sandstones, shales and claystones with minor coals; the sandstones are more common towards the top.

*Well log response.* The base is defined by a sharp increase in gamma ray response to high, irregular, patterns and an increase in bulk density. The gamma ray response contrasts with blocky to bell-shaped pattern of the underlying unit.
Depositional environments. The Formation is thought to have been deposited in tidal flat to flood plain environments, with individual sandstone units representing estuarine and tidal channels.

2.3.2.5. Stø Formation

Age. The Stø Formation is of Late Pliensbachian to Bajocian age (approx. 182.7-170.3 Ma). The base is diachronous, younging from west to east in the Hammerfest Basin.

Lithology. The formation consists of moderately to well-sorted sandstones, with thin units of shale and siltstone. Phosphatic lag conglomerates are found in some wells, especially in upper parts of the unit.

Well log response. The base is defined by a sharp transition to blocky-to-smooth cylindrical patterns, which contrast with the underlying unit. Density readings gradually decrease upwards over the boundary.

Depositional environments. The sands are interpreted to have been deposited in prograding coastal environment. Shale and siltstone intervals represent regional transgressive events. During the Early Toarcian (Toarcian – approx. 174.1-182.7 Ma) transgression in the southwestern Barents Sea, the depositional environment changed from flood-plain to prograding coastal settings. During the Late Toarcian, shallow marine depositional environments were present over most western basins in the Barents Sea. During this time, sandstones, siltstones and minor shale of the Stø Formation were deposited on the Bjarmeland Platform and in the Hammerfest, Nordkapp and Bjørnøya Basins. In the Bajocian (approx. 168.3-170.3 Ma) the Middle Jurassic regression had reached a maximum, exposing large parts of the shelf to erosion, creating a depositional gap over most of the western Barents Shelf (Smelror et al., 2009).

Core photographs of the Stø Formation are shown in Figure 2.8.

2.3.3. Adventdalen Group

2.3.3.1. Fuglen Formation

Age. The Fuglen Formation is of Late Callovian to Oxfordian age.

Lithology. The formation consists of pyritic dark brown shales with interbedded white-to-brownish grey limestones.

Well log response. The base is defined by a sharp increase in gamma ray and density responses and a decrease in interval transit time.

Depositional environments. The formation is thought to have been deposited in a marine environment during a highstand with ongoing tectonic movements.

Core photographs of the Fuglen Formation are shown in Figure 2.9.

2.3.3.2. Hekkingen Formation

Age. The Hekkingen Formation is of Late Oxfordian-Early Kimmeridgian to Ryazanian age.

Lithology. The formation consists of brownish-grey to very dark grey shale and claystone with occasional thin interbeds of limestone, dolomite, siltstone and sandstone.

Well log response. The base is defined by a sudden increase in interval transit time
and a sudden decrease in bulk density responses.

**Depositional environments.** The formation has been deposited in deep marine environments under anoxic conditions. Local barriers to circulation by Kimmerian movements caused the anoxic conditions.

Core photographs of the Hekkingen Formation are shown in Figure 2.9.

Figure 2.9: Core photographs of the Fuglen Formation (1370-1375 m MDKB) from well 7321/9-1 (left); and Hekkingen Formation (1167-1168 m MDKB) from well 7226/11-1 (right). Note that both wells fall outside the study area. Well 7321/9-1 is located in the southern part of the Fingerdjupet Sub-basin, while well 7226/11-1 is located on the southeastern part of Norsel High (from NPD, 2016).
2.4. Petroleum systems

As described by Magoon and Dow (1994), the petroleum system is a level of hydrocarbon investigation between that of a sedimentary basin and a play. For a Petroleum system to exist, a pod of active source rock, all related hydrocarbons and all the essential elements (source rock, reservoir rock, seal rock, overburden rock) and processes (trap formation, generation-migration-accumulation of hydrocarbons) must be present. The source rock may presently be inactive or depleted. The mentioned essential elements and processes must be correctly placed in time and space so that a petroleum accumulation can occur. Identification of a petroleum system begins with the discovery of hydrocarbons, regardless of the amount, and continues with the determination of the stratigraphic, geographic, and temporal extent of the system.

2.4.1. Source rocks

A rock that has generated, is generating, or may generate hydrocarbons is a source rock. This definition can be broken down to include more detail, viz., (i) an effective source rock has or is presently generating and expelling hydrocarbons, regardless of the amount; (ii) a potential source rock has enough organic matter for hydrocarbon production, but has neither reached thermal maturity, nor is generating bacterial gas; (iii) an active source rock is generating and expelling hydrocarbons at the critical moment; (iv) an inactive source rock is not generating hydrocarbons, but has the potential to do so. This is possible if the source rock has been uplifted; and (v) spent oil source rock is overmature for oil generation, but is capable of generating wet and dry gas (Peters and Cassa, 1994).

According to Ohm et al. (2008), source rocks at all stratigraphic intervals from the Carboniferous to the Cretaceous have been identified in the Norwegian Barents Sea. Hydrocarbon generation must have occurred over a long geologic history and therefore the province may represent an overfilled petroleum system. However, uplift and erosion during the Cenozoic is believed to have caused depletion of petroleum accumulations in the region. A summary of significant source rocks in the southwestern Barents Sea is given in Table 2.1. In the following, the Early-Middle Triassic and Late Jurassic marine source rocks are discussed.

2.4.1.1. Triassic source rocks

The Middle Triassic Botneheia Member consists of black phosphatic shale on Spitsbergen. Equivalents of this unit have been found in the southern Norwegian Barents Sea (Doré, 1995). This source rock is widespread and mature enough for oil generation in most places, except for the Hammerfest and Nordkapp Basins, where it is thought to be mature for gas generation. Upper Triassic delta plain shales of the Snadd Formation may also locally be of source quality in the Norwegian sector (Johansen et al., 1993).

2.4.1.2. Jurassic source rocks

Anoxic shales of the Upper Jurassic are thought to be the major oil source, while coals and carbonaceous shales of the Lower Jurassic are the major source for gas (Doré,
The Upper Jurassic Hekkingen Formation organic rich shale is the most widely distributed and best quality unit. Unfortunately, it is believed to have matured enough for oil and gas production only in a small area at the western margin of the Hammerfest Basin and along the western edge of the Loppa High. This unit is immature to the east, and overmature to the west (Ohm et al., 2008; Doré, 1995).

2.4.2. Reservoir rocks

The largest proportion of hydrocarbons proven in the Barents Sea lie within Jurassic age strata. The largest hydrocarbon discoveries (Snøhvit, Albatross, Askeladden) have a main reservoir in the Lower-Middle Jurassic Stø Formation (see Section 2.3.2.5). Within the Hammerfest Basin this has been found to have high porosity and permeability (Doré, 1995).

Fluvial, deltaic, shallow marine, tidal and estuarine sandstones of the Snadd, Kobbe and Klappmyss Formations have Triassic reservoir rocks, with several hydrocarbon discoveries: Goliat field (oil and gas in Kobbe Fm. and the Realgrunnen group); Tornerose (gas/condensate in Upper Triassic sandstone), Nucula Obesum (oil and gas in Triassic sandstone) and Caurus (gas in Snadd Fm.; oil and gas in Kobbe Fm.) discoveries. Due to the large distance from the source (Novaya Zemlya), Triassic deposits in the Norwegian sector are sand-poor, discontinuous and generally do not make good reservoirs (Lerch et al., 2016; Doré, 1995).

2.4.3. Hydrocarbon plays

Hydrocarbon plays in the southwestern Barents Sea have been summarised by Lerch et al. (2016) and are presented in Table 2.1. Below, only the Triassic and Jurassic plays are described in more detail.

2.4.3.1. Triassic plays

Triassic plays are widely distributed. They have been found in the Bjørnøya, Hammerfest and Nordkapp Basins and on the Loppa High, Bjarmeland and Finnmark Platforms. In areas where the Jurassic sandstones are missing, too thin or too shallow, the Triassic has been targeted. Main trap types are fault bounded, but many stratigraphic traps have also been mapped and postulated. The main limitations for Triassic units are the lack of clean sandstones and a reduction of porosity and permeability through diagenesis (Doré, 1995; Lerch et al., 2016).

2.4.3.2. Jurassic plays

Jurassic plays are widely distributed. Lower to middle Jurassic plays have been found in the Hammerfest, Tromsø, Norkapp Basins, Troms-Finnmark-Fault-Complex and the Bjarmeland platform. Large gas and some oil resources have been found within the Jurassic play in the Norwegian Barents Sea. The source rocks are Lower-Middle Triassic Steinkobbe Fm., Upper Jurassic Hekkingen Fm., and shales of Carnian age in the Nordkapp Basin, while the reservoir rocks are the sandstones of the Tubåen and Stø Formations (Fjaeran and Spencer, 1991; Lerch et al., 2016).
| Table 2.1: Petroleum Plays in the southwestern Barents Sea. Abbreviations: Fm. = Formation; TFFC = Troms-Finnmark Fault Complex (from Lerch et al., 2016) |
|----------|-----------------|-----------------|---------------------------------|
| Age      | Area             | Reservoir rock  | Depositional environment       |
|          | Discoveries     | Source rock     | Type                           |
|          | in Wells        | in Wells        |                                |
| Late Jurassic to Early Cretaceous | Mainly distributed in the western part of the western Barents Sea | Sandstones of the Knurr and Kolje Formations | Shallow to moderately deep |
|          | Wells 7120/1-2, 7120/2-2, 7120/2-3S and 7220/10-1 | Upper Jurassic Hekkingen Fm | Stratigraphic pinch-out, structural |
|          |                  |                |                                |
| Early to Middle Jurassic | Hammerfest Basin, TFFC, Tromsø Basin, Bjarmeland Platform, Nordkapp Basin | Sandstone of the Tubåen and Stø Formations | Fluvial, deltaic, estuarine tidal and shallow marine |
|          |                  |                | Rotated fault blocks and horst structures, stratigraphic traps related to salt diapirs in the Nordkapp Basin |
|          |                  |                |                                |
| Lower-Middle Triassic | Steinkobbe Fm, Upper Jurassic Hekkingen Fm, shales of Carnian age in the Nordkapp Basin | Lower-Middle Triassic | Stratigraphic, structural |
|          |                  |                |                                |
| Triassic | Loppa High, Bjarmeland, and Finnmark Platforms | Sandstones of the Snadd, Kobbe and Klappmyss Formations | Fluvial, deltaic, shallow marine, tidal and estuarine |
|          |                  |                | Stratigraphic, combination of stratigraphic and structural is possible |
| Carboniferous to Early Permian | Loppa High, Finnmark Platform | Limestones, dolomites, spiculites/cherts, silicified carbonates and sandstones | Marine, temperate water and marginal to shallow marine |
|          |                  |                | Combination of reef and platform, shelves and deeper Carboniferous coal and carbonaceous shales |
|          |                  |                |                                |
| Mississippian | Loppa High, Finnmark Platform | Sandstone and conglomerates | Fluvial and alluvial, river and floodplain deposits |
|          |                  |                | Structural and stratigraphic |
|          |                  |                |                                |
2.5. Effects of uplift and erosion on petroleum systems

The Barents Sea has experienced severe uplift and erosion during the Cenozoic (Figure 2.10), which is considered as being the most significant problem for oil exploration. This is especially relevant to the Norwegian sector (Doré, 1995). In some wells, residual oil shows were found at or below the present spill-point of the trapping structures, which may indicate originally completely filled reservoirs with large amounts of saturated oil (Skagen, 1993).

![Figure 2.10: Uplift estimation map illustrating the total amount of uplift based on vitrinite data (from Ohm et al., 2008). Red rectangle indicates the study area.](image)

Two distinct periods of uplift and erosion have been identified. The first may be linked to the opening of the Norwegian-Greenland Sea. The second - with the post Miocene glaciations. The bulk of the erosion took place during Late Neogene (Nyland et al., 1992).

The results of hydrocarbon exploration in the Barents Sea have been somewhat disappointing, with the lack of commercially attractive reserves attributed mostly to the mentioned Cenozoic uplift and erosion. However, a larger part of the world’s current hydrocarbon resources have been found onshore. Most of these areas have seen recent uplift and erosion (since erosion is commonly a geologically rapid process, uplift must be faster than erosion in order for the land to remain emergent). Such simple observations oppose the notion that upliftment necessarily causes negative effects on hydrocarbon potential (Doré and Jensen, 1996).

Both positive and negative effects of the late Cenozoic uplift and erosion on hydrocarbon exploration offshore Norway have been summarized by Doré and Jensen (1996)
and are briefly listed below.

### 2.5.1. Negative effects

- **Changes in structural attitude.** The amount of uplift in the Barents Sea has been estimated using various techniques (Nyland et al., 1992; Walderhaug, 1992; Rasmussen and Fjeldskaar, 1996; Ohm et al., 2008; Baig et al., 2016) and shows uplift values ranging from 0 to 3000 m. Maximum values have been obtained in the Northwest, towards the Stappen High and in the south next to onshore Norway. Minimum values have been obtained in the axial parts of the Hammerfest and Tromsø Basins. It is therefore argued that pre-existing petroleum accumulations in hinge areas would have been tilted, causing substantial spillage, especially in low relief structures. Uplift may also have created new structural traps not present in the past. In cases where upliftment caused petroleum generation to cease, such traps would be empty (Doré and Jensen, 1996).

- **Gas expansion and exsolution from oil.** Erosion of overburden causes a pressure drop and a subsequent gas expansion and/or gas exsolution from liquid hydrocarbons (Figure 2.11). Structures that were filled to spill would in such cases expel petroleum, resulting in shorter oil legs and/or less dense gas accumulations. These effects are thought to have occurred in the Snøhvit Field and in other nearby gas fields in the Hammerfest Basin, such as Askeladden and Albatross Fields (Doré and Jensen, 1996; Nyland et al., 1992).

![Figure 2.11](image)

**Figure 2.11:** Illustration showing the effects of uplift on cap-rock properties and the fill-spill mechanism. a) Tight cap rock scenario. Gas expands due to uplift, forcing the oil to remigrate updip into the second trap. There, it separates into a gaseous and liquid phase, the gas expands again, forcing the oil to remigrate further updip. b) Brittle cap rock model. Gas expands due to uplift, forcing the oil to remigrate updip into the second trap. Cracks in the cap rock cause leaking of gas, but retains oil. In the final trap, erosion of the cap rock leads to loss of hydrocarbons. Green = oil; red = gas (from Lerch et al., 2016)

- **Seal failure.** According to (Sales, 1993), a shale’s strength (which is a function of compaction and dewatering) should match the overburden stress and, when uplifted, retain the strength inherited during maximum burial. Several scenarios may contribute to seal failure during uplift: (i) a seal may pass from plastic...
through shear and into tension-failure strength fields, which would increase
the chance of failure; (ii) if uplift is uniform, hydraulic failure may occur due
to the decrease in overburden pressure; (iii) tilting may cause overpressure in
the deeper parts of a pressure compartment. As overburden is being eroded
away from the marginal parts of this compartment, susceptibility to hydraulic
fracturing increases; and (iv) deformation may create additional stresses.

First glaciation can be expected to remove most overburden, but the ice may
partially substitute for the weight removed. Therefore, the greatest stress on seals
could occur during the first deglaciation. This has possibly happened in some
parts of the Barents shelf (Sales, 1993).

- **End of petroleum generation.** Temperature is the most sensitive factor for hydrocar-
bon maturation (Tissot et al., 1987). Uplifted source rocks would therefore likely
have cooled down and no new hydrocarbons could have been generated which
would be able to fill into previously depleted traps (Doré and Jensen, 1996).

On the other hand, unexpelled oil in the source rocks could theoretically have
exsolved gas due to loss of pressure. It is possible, therefore, that late-stage gas
charging of structures could have occurred in the Barents Sea (Doré and Jensen,
1996).

- **Overmature source rocks.** In contrast with the previous, source rocks which cur-
rently appear to be at depths suited for oil generation may have previously been
buried deep enough to have passed the *oil window* and experienced *gas window*
temperatures. In addition, oil reservoirs may have experienced temperatures
high enough for oil cracking (Doré and Jensen, 1996).

- **Reservoir deterioration.** Diagenetic processes (grain deformation and fracturing,
precipitation of cement, development of stylolites) generally reduce the porosity
and permeability and uplifted rocks show a diagenetic state which reflects their
maximum burial depth. Quartz cementation is controlled by temperature. It starts
at about 70-80°C and increases by a factor of about 1.7 for every 10°C temperature
increase. Cementation continues during uplift as long as the temperature is above
70-80°C and any new fractures formed due to elastic expansion caused reduced
stress will likely be filled with cement (Bjørlykke and Jahren, 2015). Uplifted
reservoir rocks should therefore have lower reservoir quality than expected at
that depth if no uplift had occurred (Doré and Jensen, 1996).

- **Biodegradation of oil.** No oil accumulated in a trap can preserve it’s original
composition and properties for a long amount of time, because it is subject to
constant secondary alteration processes. One of these processes that may affect
the oil is biodegradation, which is known to be able to reduce the quality of
petroleum in reservoirs greatly (Blanc and Connan, 1994). Around half of the
oil and residual oil found at shallow depths in the Barents Sea is biodegraded
(Henriksen et al., 2011a). Therefore it is important to understand if and how
upliftment in the Barents Sea could have influenced biodegradation. A study
by Wilhelms et al. (2001), for example, suggests that petroleum reservoirs which
have been heated to temperatures above around 80-90°C may be sterilized and unaffected by biodegradation.

2.5.2. Positive effects

- **More mature source rocks.** Source rocks in areas that have undergone upliftment should have source rocks which are more mature than normally expected, because they will have been buried deeper in the past. Therefore, measurements of uplift in areas where source rocks are above the expected oil window can be very important (Doré and Jensen, 1996).

- **Redeposition.** Areas adjacent to uplifted areas could have seen rapid deposition of erosion products, causing accelerated maturation of source rocks. Such effects are known elsewhere on the Norwegian continental shelf and it is believed that a substantial proportion of Norwegian petroleum reserves has been generated and distributed due to burial by Late Cenozoic erosion products (Doré and Jensen, 1996).

- **Methane exsolution from formation water.** Many petroleum basins globally have formation brines containing high concentrations of dissolved methane, which forms as a result of thermal maturation of organic matter and is dissolved in the water. Exsolution of this methane from brine during uplift due to decrease in pressure could result in large gas accumulations. Very large gas resources may thus be present in the Barents Sea, awaiting the economic incentive to drill for them (Doré and Jensen, 1996).

- **Uplift effect on sealing capabilities.** Despite considerable uplift, many shale seals found around the globe are known to have retained their sealing capacity. Other seals, such as evaporites, are known to retain their sealing capacity through practically any deformation as long as the layer is not breached. In the southeastern Norwegian sector, Late Carboniferous to Early Permian evaporites are known from the Nordkapp Basin and are thought to be more extensive. These could have preserved petroleum generated from Palaeozoic source rocks (Doré and Jensen, 1996).

Weaker Class 1 traps may be converted to Class 2 during uplift and start to leak gas before their oil is flushed. Class 2 traps may decrease their gas cap as the gas gradient steepens and increase their oil column, because Class 2 traps have excess sealing capacity for oil (Sales, 1993). Effect of good versus bad cap rock quality on the hydrocarbon retention is shown in Figure 2.12.

- **Fracturing of reservoirs.** Fracturing within reservoirs creates additional porosity and permeability and may enhance interconnectivity by dilatational effects along faults. Reservoir rocks are normally considerably more susceptible to brittle fracturing than cap rocks. Therefore it is possible to enhance the quality of reservoirs during uplift, while at the same time preserving the sealing capacity of cap rocks (Doré and Jensen, 1996).
• Remigration. Hydrocarbons lost from structures due to the failure of cap rocks, spillage and expansion have the possibility to remigrate to shallower structures (Doré and Jensen, 1996).

Figure 2.12: Effect of good versus bad cap rock quality on hydrocarbon phase in the traps along migration avenue towards basin periphery. Strong seal rock that can hold significant volumes of gas will favour gas accumulation and oil spillage. Cap rocks with poorer sealing quality may allow gas to escape but retain oil. A similar effect can be expected for uplifted traps (from Ohm et al., 2008).
CHAPTER 3

Methodology and theoretical background

3.1. Workflow

The main objective of this project has been to image the reservoir qualities of the Triassic and Jurassic Kobbe, Snadd and Stø Formations on the Bjarmeland Platform, Norwegian Barents Sea. The first step involved the study of published geological literature, in order to get acquainted with the geological developments both on the larger scale, involving the entire Barents Sea region, and on the smaller scale, including depositional environments of specific formations and the diagenetic processes that they were subjected to. Geophysical literature was then studied and appropriate methods selected to be used on the available geophysical data. Results of the study were then interpreted and discussed along with the analysis of the major uncertainties. Finally, recommendations were made concerning the means of study that may be employed for future analysis and to get a better understanding of the reservoir quality, petroleum potential and issues concerning exploration and development, among other things. A summary of the workflow used during this study is given overleaf (Figure 3.1).

3.2. Quality control assessment of well log data

The caliper tool measures the size and shape of the borehole. Perhaps the most important use of the tool is for quality control of other logs. Intervals in the borehole that have much larger diameter than the drilling bit are ‘caved’ or ‘washed out’. This sometimes happens when the borehole walls cave in due to the turning drill pipe or the circulation of the drilling fluid, and is typical for unconsolidated shales. Mud weight less than the pore pressure and/or improper bit jet velocity may also cause an overgauge hole. Other lithology types, such as coal beds, organic shale layers and others can also cave in. In places with serious caving, the logging tools are no longer in contact with the borehole wall and their readings start to become more indicative of the drilling fluid than the actual formations. Log readings in such cases may need excessive corrections and may be completely unreliable (Rider and Kennedy, 2011).

The first step in well log quality control was to note significant borehole cavings or washouts as indicated by the caliper log. The biggest problems occurred in well 7228/2-1S, where nearly the full interval of Kobbe and Snadd Formations showed significant cavings. The neutron, density and sonic logs were visually strongly affected by the cavings, however, it was difficult to assess whether or not the gamma ray log...
CHAPTER 3. METHODOLOGY AND THEORETICAL BACKGROUND

Future work

Petrophysical analysis

Rock physics diagnostics

Forward AVO modelling

Reservoir characterization

Geological & Geophysical literature study

Petroleum systems

Tectonic evolution

Study of geophysical methods

Depositional systems & stratigraphy

Structural elements

Recent evolution

QC of well log data

Lithology & shale volume estimation

Rock physics model creation

Uncertainty analysis

Net to gross

Reservoir & pay zone identification

Porosity estimation

Saturation estimation

Shear wave estimation

Effective medium models

Rock physics templates

Generation of synthetic seismics

Fluid substitution

Forward AVO modelling

Discussion of depositional environments

Uncertainty analysis

Preparation of well log data

Lithology & fluid discrimination

Compaction, cement & sorting trends

Fluid sensitivity analysis

Effect of choice of various parameters of synthetic seismics

Seismic interpretation

Sedimentological analysis & petrographical study of cores and cuttings

Source rock study

Thin section analysis

Uncertainties associated with uplift and erosion

Source rock study

Figure 3.1: Workflow chart describing the main steps followed in this study along with recommendations for future work. QC = quality control.
was affected. The observed issues with well log data quality are presented in Table 3.1. Interpretation of these intervals may be strongly affected by data quality and less reliable.

Table 3.1: Intervals with significant cavings.

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Bit size (in)</th>
<th>Caliper range (in)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Stø</td>
<td>9.87</td>
<td>9.87-12.03</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Snadd</td>
<td>N/A</td>
<td>12.2-25.9</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>N/A</td>
<td>8.2-16.0</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Snadd</td>
<td>N/A</td>
<td>13.9-26.0</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>N/A</td>
<td>14-26.3</td>
</tr>
</tbody>
</table>

An example of significant caving in well 7228/2-1S is shown in Figure 3.2 below:

Figure 3.2: Example of poor data quality over Kobbe and Snadd Formations in well 7228/2-1S. Note the strong kicks in the density and neutron logs associated with borehole caving.
3.3. Uncertainties related to uplift and erosion

Porosity and permeability are considered to be the most important reservoir properties, critical for the extraction of hydrocarbons. Two main domains influence these sandstone properties: (i) sedimentological conditions, which are influenced by provenance area, climate, transport and depositional environments, among others, and control the mineralogical composition, grain size and texture; and (ii) the diagenetic processes occurring both near the surface and during burial (Bjørlykke and Jahren, 2015).

The study area has been subjected to significant uplift and erosion during the Cenozoic. This means that the reservoirs were buried much deeper than their present depth. Reservoir properties may therefore be expected to be significantly affected by the effects of burial (compaction and consolidation).

This section introduces theory related to the processes affecting sediments during increasing burial (namely, mechanical and chemical compaction). The effects of burial on the velocity-depth trends in the study area are then observed and discussed, referring to published literature on the uplift and erosion in the SW Barents Sea.

3.3.1. Mechanical compaction

Mechanical compaction of sediments occurs due to increased effective stress from the overburden and starts immediately after sediment deposition. There is an overall drive towards lower porosities with depth, which in the mechanical compaction window is achieved by the reorientation and crushing of grains. This allows for a more compact packing. The reduction in bulk volume here is equal to the loss of porosity. The initial grain size, sorting and grain framework strength control the loss of volume during mechanical compaction. Well sorted, smaller grain size sands tend to resist compaction better than coarse grained sands. Where rapid sedimentation occurs, the pore fluids may be trapped by an impermeable overlying layer, which could prevent the loss of fluids. In such cases, the fluids resist increasing overburden pressure and mechanical compaction is hindered, resulting in overpressured zones (Bjørlykke, 2015).

The overall loss in porosity results in increased density. The average contact points per grain also increases with better packing, strengthening the rock matrix. This results in increased density and P-wave log responses. Although the P-wave velocity is inversely proportional to the sediment density, the increase in shear and bulk density with decreasing porosity is more rapid, resulting in higher $V_P$ values.

3.3.2. Chemical compaction

Chemical compaction regime represents a chemically closed system and involves dissolution, precipitation and cementation of the grain framework. The boundary between mechanical and chemical compaction occurs at around 70-80°C. Quartz cementation begins at this temperature and does not stop until nearly all of the porosity is lost, or the temperature drops below the threshold. The depth at which this process occurs depends on the geothermal gradient of the sedimentary basin. For quartz cementation to occur, nucleation surfaces must be present. Other types of cement or
chlorite coating can prevent quartz cementation, even at high temperatures. The rate of quartz cementation increases with temperature, therefore chemical compaction is a function of thermodynamics and kinetics (Bjørlykke, 2015).

The first 2–4% of quartz cement greatly increases the strength of the rock framework and practically stops further mechanical compaction (Bjørlykke and Jahren, 2015). Such rapid increase in rock stiffness rapidly increases the sonic velocity, which is commonly seen in a depth versus velocity log as a sudden increase in velocity values.

3.3.3. Estimations of uplift and erosion in study area

It is well known that rock density and P-wave velocity tend to increase, and porosity tends to decrease with increasing burial depth. Well log data is therefore expected to follow a certain general trend with burial depth. Divergence from the trend can occur due to variations in lithology, fluid type and pore pressure. At the onset of chemical compaction (70-80°C), the first few percent of cement have a strong grain framework stiffening effect. This can often be seen in a depth versus velocity plot as a sudden increase in velocity values.

Distinguishing between the mechanical and chemical compaction zones is useful for the purpose of uplift estimation. A common procedure involves plotting the depth versus velocity data together with one or several published compaction trends. If we assume that the mechanically compacted sediments within the study area followed a certain trend, similar to one of the published trends, a comparison between the actual velocity-depth trend and the empirically derived trend can be made to estimate the amount of uplift.

Several important uncertainties associated with this type of study should be mentioned:

• The published trends provide empirical information, which strictly only applies to the rocks that were studied and the conditions of the study.

• Many uncertainties are involved in determining the chemical compaction boundary. The knowledge of the study area and experience of the interpreter are very important. If, for example, the amount of uplift is high, only a thin section of mechanically compacted sediments may be preserved or they can be completely eroded. In this case, chemically compacted sediments may be wrongly interpreted as belonging to the chemical compaction window.

• It is necessary to confirm that a sudden increase in velocity is not related to a change in lithology. Carbonates and evaporites, for example, can have much larger velocities than surrounding sandstones and shales. It may be beneficial to compare the velocity log with other logs, such as density, resistivity, gamma ray or others. The onset of cementation rapidly increases the rock stiffness, but is not expected to show a strong increase in density. Other lithologies, such as carbonates, often have higher densities and velocities than surrounding rocks. A sudden increase in velocities may therefore be related to the presence of carbonates. Salt also has high velocities, but a low density.
Having reviewed the velocity trends in all wells, 7228/1-1 and 7228/2-1S were selected for uplift estimation (Figure 3.3). These wells appeared to show relatively thick intervals of mechanically compacted sediments and a clear change in velocity-depth trends, which were associated with the shift from mechanical to chemical compaction (for velocity depth trends in all available logs, please see Appendix A).

![Diagram](image)

**Figure 3.3:** Transition zone and uplift estimations for wells 7228/1-1 – a), b); and 7228/2-1S – c), d). MC – mechanical compaction; CC – chemical compaction; KMBSF – kilometres below sea floor. Transition zone estimations were performed using all velocity data a), c); uplift estimations were performed for data points that were considered to represent shale b), d).

Many experimental compaction curves have been published, which show velocity-depth trends. In this study, uplift was estimated by comparing the observed velocity-depth trends with those published by Storvoll et al. (2005); Mondol et al. (2007); Mondol (2009); Marcussen et al. (2010). Transition zone was estimated from the entire velocity data set in each well, while uplift estimations were performed for data points that were considered to represent shale. The gamma ray log was used as lithologic control to estimate the volume of shale. The shale boundary was set to >190 API for well 7228/1-1 and >80 API for well 7228/2-1S.
Figure 3.4: Net exhumation estimate map (modified from Baig et al., 2016) – left; and net erosion estimate map (modified from Henriksen et al., 2011a) – right. The approximate well locations from this study are marked by red dots. A – 7324/7-1S, B – 7324/8-1 (Wisting), C – 7324/10-1, D – 7225/3-1 (Norvarg), E – 7225/3-2 (Norvarg), F – 7226/2-1 (Ververis), G – 7228/1-1, H – 7228/2-1S.

The velocity depth trends in both wells appear to have the best fit with the empirical compaction curve published by Storvoll et al. (2005). Approximate amount of uplift, estimated by comparison with the Storvoll et al. (2005) compaction curve, is 1600 m in well 7228/1-1 and 1800 m in well 7228/2-1S. Although many uncertainties are involved in this type of study, the results are similar to the work by other authors. Several studies have dealt with the uplift and erosion estimations of the Barents Sea. Figure 3.4 shows uplift and erosion estimation maps produced by Henriksen et al. (2011a) and Baig et al. (2016). Approximately 1500-1600 m uplift is estimated in the study area by Baig et al. (2016). In comparison, Henriksen et al. (2011a) estimate between 1500-2200 m erosion in the study area.

Zone of transition between mechanically and chemically compacted sediments was estimated to be at approximately 600 m in well 7228/1-1 and 800 m in well 7228/2-1S. In order to reduce the uncertainty concerning the discrimination of this zone, the inferred transition zone depth was corrected for uplift and compared to an estimate of the depth at which it is expected to occur, assuming the current geothermal gradient.

The geothermal gradient can be estimated from the bottom hole temperature using the equation $G = \Delta T / \Delta z$, where $G$ – geothermal gradient, $\Delta T$ – change in temperature, $\Delta z$ – change in depth. The change in temperature has been estimated by assuming that the sediment temperature at sea bottom is 4°C. No bottom hole temperature was available for well 7228/1-1, therefore the geothermal gradient was interpolated from the gradient of the neighbouring wells 7225/3-2 and 7228/2-1S.

As previously mentioned, chemical compaction in sandstones is thought to begin at around 70-80°C, while the theoretical temperature range for the onset of chemical compaction in mudrocks is between 70-100°C (Mondol et al., 2007; Thyberg et al., 2010). The latter range, combined with the calculated geothermal gradient, was used to
Table 3.2: Current versus estimated transition zone depths. Uplift – approximate uplift by comparison with the compaction curve by Storvoll et al. (2005); G – geothermal gradient; TZ curr. – current depth at which the transition zone is observed; TZ adj. – transition zone adjusted for uplift; TZ est. estimated depth range of the onset of chemical compaction with current geothermal gradient. *Due to missing bottom hole temperature data, the geothermal gradient in well 7228/1-1 was interpolated from the neighbouring wells 7225/3-2 (34°C) and 7228/2-1S (32°C).

<table>
<thead>
<tr>
<th>Well</th>
<th>Uplift (m)</th>
<th>G (°C)</th>
<th>TZ curr. (m)</th>
<th>TZ adj. (m)</th>
<th>TZ est. (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7228/1-1</td>
<td>1600</td>
<td>33*</td>
<td>600</td>
<td>2200</td>
<td>2000-2909</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>1800</td>
<td>32</td>
<td>800</td>
<td>2600</td>
<td>2058-2993</td>
</tr>
</tbody>
</table>

predict the depth at which chemical compaction should begin in each individual well. Results are shown in Table 3.2. The uplift-corrected estimated transition zone falls toward the lower range of expected onset of chemical compaction in well 7228/1-1, and slightly towards the higher range in well 7228/2-1S.

We see that the study area has been subjected to significant uplift and erosion. The studied reservoirs were subjected to much higher depth than that at which they are presently found. It can therefore be expected that the degree of compaction and consolidation of these reservoirs may be much higher than expected from just the present depths and temperature gradients. This must always be kept in mind when performing geophysical analyses in the study area and the SW Barents Sea in general.
3.4. PETROPHYSICAL ANALYSIS

Petrophysics is the study of the physical properties of rocks, or, more precisely, how the physical properties of rocks are affected by the amount and arrangement of various minerals of which they are comprised and the fluids they store. In practice, the reverse problem is most often considered, i.e. using the measured physical properties to determine the composition of rocks in the subsurface (Kennedy, 2015).

The origins of petrophysics lie with the petroleum industry, therefore most of the tools and techniques that are available have been developed to describe porous sedimentary rocks. Specifically, the problem of determining what the rock is made of is often reduced to finding three properties: porosity (capacity of the rock to store fluid), saturation (of brine and hydrocarbons) and permeability (how difficult it is to extract). These are often called petrophysical properties. The methods developed to find these properties can also be used for finding other important information, such as identifying mineralogy or modelling seismic response between certain rock interfaces (Kennedy, 2015).

Before quantification of porosity or water saturation can be made, reservoir lithology and formation water resistivity must be known. Ideally these would be known from fluid samples, core samples and/or cuttings. However, due to high cost and other challenges, this is not often the case. Geophysical log data can be used to estimate gross lithology as part of porosity interpretation, while formation water resistivity can be estimated using the range of available resistivity tools (Cannon, 2015).

Petrophysical evaluation is commonly performed in the following sequence: shale volume, porosity, water saturation. The shale volume is used as input for the evaluation of effective porosity, shaly-sand saturation and other equations. Saturation is defined as a certain percentage of porosity, and therefore can only be computed after porosity (Kennedy, 2015). In the following sections of this chapter, the methodology and theory behind the petrophysical analysis is discussed in the same order as it has been performed during the project.

3.4.1. Shale volume estimation

The determination of shale volume within a reservoir is very important as it may strongly affect the estimates of reserves and producibility. As described by Ellis and Singer (2008), the clay minerals present in shale can have several important implications:

- Even low amounts of clay minerals within the pore volume can strongly affect permeability.
- Permeability may be further reduced by introducing improper fluids to the reservoir, without the consideration for the clay minerals present.
- The presence of clay affects nearly all well log responses and thus the estimates of various properties computed from these logs. For example, the presence of hydrogen in clay minerals causes overestimations of porosity derived from the neutron log. Clay minerals may also reduce the resistivity reading, leading to underestimation of hydrocarbon saturation.
CHAPTER 3. METHODOLOGY AND THEORETICAL BACKGROUND

The terms shale and clay are often used interchangeably. To be more precise, a shale is defined as a fine-grained rock having a significant fraction of clay minerals, the remainder being made up of silt or sand-sized grains of quartz, other silicates, carbonates and organic matter. In fact, shales commonly contain 60-80% clay by volume. On the other hand, sandstones commonly contain some amount of clay, so that clay volume in sandstone will be more than 0% even when no shale is present. This small amount of clay may compensate for the non-clay component of the shale in shaly sandstones, which may allow using the terms clay and shale interchangeably, even though this is not strictly correct (Kennedy, 2015). Where log measurements are concerned, the average properties of silt resemble those of sand, while the properties of clay are distinctly different, so that it is difficult to discriminate the silt fraction from the logs (Ellis and Singer, 2008).

Pure clay beds are uncommon and thus well log readings in a pure clay bed in a particular area are unlikely to be measured. Shale beds, on the other hand, are very common, therefore log readings in pure shale can easily be determined. The most commonly used and widely applicable methods for the evaluation of shale volume are the gamma ray (including spectral gamma ray) and the neutron-density combination (Kennedy, 2015). Both methods were used in this thesis project and their application is discussed below.

3.4.1.1. Shale volume from Gamma Ray

The gamma ray log measures a formation’s natural gamma radiation. This radiation emanates essentially from three elemental sources: the radioactive isotopes of the elements potassium, thorium and uranium. Their half-lives – $^{40}$K: $1.3 \times 10^9$ years, $^{232}$Th: $1.4 \times 10^{10}$ years, and $^{238}$U: $4.4 \times 10^9$ years – are comparable with the age of the earth, which allows for a significant amount of the original material to be present in the earth’s crust, while decaying at a measurable rate (Ellis and Singer, 2008; Rider and Kennedy, 2011).

Potassium is significantly more abundant in the earth’s crust compared with the other two elements. However, its contribution to the overall radioactivity relative to its weight is small. The opposite is true for Thorium and Uranium - while only trace amounts occur in sedimentary rocks, their contribution to the overall radioactivity is of the same order of magnitude (Rider and Kennedy, 2011) (see Table 3.3).


<table>
<thead>
<tr>
<th></th>
<th>K</th>
<th>Th</th>
<th>U</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relative abundance in the earth’s crust</td>
<td>2.59 %</td>
<td>12 ppm</td>
<td>3 ppm</td>
</tr>
<tr>
<td>Gamma rays per unit weight</td>
<td>1</td>
<td>1300</td>
<td>3600</td>
</tr>
</tbody>
</table>

The common assumption of the gamma ray log being a good shale volume indicator is not backed by a strong scientific argument as explained in the next section (Section 3.4.1.2). Nevertheless, in practice it is common that a higher gamma ray count
corresponds to an increase in shale volume (Kennedy, 2015).

The simplest method for estimating shale volume from the gamma ray log is one that assumes a linear relationship. It is taken that the values for pure shale in any one area, well or zone of a well are constant, even though generally the gamma ray values for shales may vary significantly. On this presumption, the maximum average gamma ray log value is taken to represent 100% shale and the minimum average value to represent 0% shale. The shale volume can be calculated from the following equation (Rider and Kennedy, 2011):

\[ I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \]  

Where, \( I_{GR} \) – gamma ray index; \( GR_{log} \) – gamma ray log value in area of interest; \( GR_{min} \) – minimum gamma ray reading (no shale); \( GR_{max} \) – maximum gamma ray reading (pure shale).

The assumption of a linear relationship has no scientific basis and, in general, tends to overestimate the shale volume (Rider and Kennedy, 2011). Overestimation is caused by a decrease in the depth of investigation of the gamma ray tool with increasing formation density. In a typical sand-shale system, density tends to be highest in the shales. This leads to a smaller volume of formation contributing to the overall gamma ray activity in shales than is sands, with the greatest discrepancy occurring at shale volume of around 50% (Kennedy, 2015). Several non-linear relationships, which take the latter into account, have been produced over the years. Some of the commonly used relationships are presented in Figure 3.5 and Table 3.4. All of these relationships show a lower shale volume, compared with the linear method, except at the extremities of 0% and 100% shale volume.

![Figure 3.5: Chart showing commonly used shale volume estimation corrections (modified from Mondol, 2015).](image-url)
Table 3.4: Commonly used non-linear equations for the estimation of shale volume from the gamma ray log.

<table>
<thead>
<tr>
<th>Author(s)</th>
<th>Equation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Larionov (1969) ‘Young rock’</td>
<td>( V_{sh} = 0.083 \times (2^{3.7I_{GR}} - 1) )</td>
</tr>
<tr>
<td>Larionov (1969) ‘Old rock’</td>
<td>( V_{sh} = 0.33 \times (2^{I_{GR}} - 1) )</td>
</tr>
<tr>
<td>Steiber (1970)</td>
<td>( V_{sh} = I_{GR} \div (3 - 2 \times I_{GR}) )</td>
</tr>
<tr>
<td>Clavier et al. (1971)</td>
<td>( V_{sh} = 1.7 - [3.38 - (I_{GR} + 0.7)^2]^{1/2} )</td>
</tr>
</tbody>
</table>

The linear equation is the correct model when the shale density is close to the sandstone density. It is also the recommended relationship to use, unless justifications can be made for using a non-linear model (Kennedy, 2015).

Table 3.5: Average estimated shale volume from the gamma ray method. \( GR_{min} \) – sand baseline; \( I_{GR} \) – shale base line; \( I_{GR} \) – average gamma ray index; L(Y) – Larionov (1969) ‘Young rock’; L(O) – Larionov (1969) ‘Old rock’; Steib – Steiber (1970); Clav – Clavier et al. (1971).

<table>
<thead>
<tr>
<th>Well name</th>
<th>Formation</th>
<th>( GR_{min} )</th>
<th>( GR_{max} )</th>
<th>( I_{GR} )</th>
<th>L(Y)</th>
<th>L(O)</th>
<th>Steib</th>
<th>Clav</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Stø</td>
<td>10</td>
<td>120</td>
<td>0.10</td>
<td>0.02</td>
<td>0.05</td>
<td>0.03</td>
<td>0.04</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>72</td>
<td>135</td>
<td>0.60</td>
<td>0.37</td>
<td>0.47</td>
<td>0.39</td>
<td>0.44</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>69</td>
<td>115</td>
<td>0.63</td>
<td>0.38</td>
<td>0.49</td>
<td>0.40</td>
<td>0.46</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Stø</td>
<td>35</td>
<td>145</td>
<td>0.10</td>
<td>0.03</td>
<td>0.05</td>
<td>0.04</td>
<td>0.05</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>57</td>
<td>145</td>
<td>0.54</td>
<td>0.32</td>
<td>0.41</td>
<td>0.34</td>
<td>0.39</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Stø</td>
<td>20</td>
<td>70</td>
<td>0.23</td>
<td>0.09</td>
<td>0.15</td>
<td>0.11</td>
<td>0.13</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
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<td>70</td>
<td>0.65</td>
<td>0.43</td>
<td>0.52</td>
<td>0.44</td>
<td>0.50</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>20</td>
<td>55</td>
<td>0.68</td>
<td>0.45</td>
<td>0.55</td>
<td>0.46</td>
<td>0.52</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Stø</td>
<td>15</td>
<td>120</td>
<td>0.26</td>
<td>0.11</td>
<td>0.17</td>
<td>0.13</td>
<td>0.16</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>40</td>
<td>120</td>
<td>0.53</td>
<td>0.32</td>
<td>0.41</td>
<td>0.34</td>
<td>0.39</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>70</td>
<td>150</td>
<td>0.63</td>
<td>0.38</td>
<td>0.49</td>
<td>0.40</td>
<td>0.46</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Stø</td>
<td>45</td>
<td>133</td>
<td>0.52</td>
<td>0.33</td>
<td>0.41</td>
<td>0.34</td>
<td>0.39</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>65</td>
<td>133</td>
<td>0.61</td>
<td>0.40</td>
<td>0.49</td>
<td>0.42</td>
<td>0.47</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>65</td>
<td>123</td>
<td>0.64</td>
<td>0.42</td>
<td>0.51</td>
<td>0.43</td>
<td>0.48</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Stø</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>170</td>
<td>240</td>
<td>0.55</td>
<td>0.34</td>
<td>0.43</td>
<td>0.36</td>
<td>0.40</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>145</td>
<td>195</td>
<td>0.58</td>
<td>0.34</td>
<td>0.45</td>
<td>0.36</td>
<td>0.42</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Stø</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>80</td>
<td>140</td>
<td>0.58</td>
<td>0.37</td>
<td>0.46</td>
<td>0.39</td>
<td>0.43</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>70</td>
<td>135</td>
<td>0.57</td>
<td>0.34</td>
<td>0.44</td>
<td>0.36</td>
<td>0.41</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Stø</td>
<td>35</td>
<td>95</td>
<td>0.51</td>
<td>0.28</td>
<td>0.37</td>
<td>0.30</td>
<td>0.35</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>30</td>
<td>90</td>
<td>0.53</td>
<td>0.31</td>
<td>0.40</td>
<td>0.33</td>
<td>0.37</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>25</td>
<td>80</td>
<td>0.45</td>
<td>0.20</td>
<td>0.30</td>
<td>0.23</td>
<td>0.28</td>
</tr>
</tbody>
</table>

In this study, the sand and shale baseline values have been determined by studying each formation interval on its own as well as in relation to the gamma ray response throughout the entire well. The sand baseline was determined by finding the thickest sandstone intervals within a formation. The shale parameter was decided by then
attempting to establish a shale bed that could be genetically related to the sand. Crain (2016) recommends that less than 10% of the data within the interval of investigation should fall outside the established constraints. Although there is no fundamental reason why a certain percentage of data should not fall outside the established constraints, the logic behind using statistics is to introduce precision into the choice of parameters.

Wells 7226/2-1 and 7228/1-1 had significantly higher gamma ray log values compared with the other wells. Nevertheless, the same relationships were considered to hold and the clean sand/pure shale baselines were shifted towards higher values to compensate for the higher readings. Results of shale volume estimation in each well and formation using the gamma ray method are presented in Table 3.5.

3.4.1.2. Correction of shale volume using spectral gamma ray log

In most cases, natural radioactivity is associated with the presence of shale. A typical shale contains approximately 6.5 ppm Uranium, 12 ppm Thorium and 2% Potassium. However, the presence of each radioactive isotope can vary significantly:

Potassium is a component of the chemical structure of clay minerals and, despite variations in specific clay minerals, has a rather constant presence in most shales of approximately 2%. However, it also occurs in detrital minerals such as micas and feldspars and therefore can be part of both the sand and shale in a formation. Potassium can be considered as being a moderately good indicator of shale.

Distribution of Uranium in shales is very irregular. In most shales, it contributes only around 10% - 30% of the total radioactivity, but may in certain cases, such as in condensed sections with a high amount of organic matter, increase strongly. Its distribution is not related to the volume of clay minerals but rather to secondary components, therefore it is a poor indicator of shale.

The amount of Thorium varies in clay mineral species, but in practice it has been shown to have a more or less constant value of 12 ppm in typical shales. In addition, it has a high contribution of around 40% - 50% to the overall radioactivity. In mixtures of carbonate, sand and shale, Thorium will occur mostly in the shale fraction. In contrast to the other two isotopes, Thorium is considered as being a very good indicator of shale (Rider and Kennedy, 2011).

The spectral gamma ray log can discriminate between the contributions of Uranium, Thorium and Potassium to the overall radioactivity. Using spectral gamma ray analysis it is possible to discriminate between shales and formations with unusual excess of the radioactive isotopes. For example, for a sand which contains minerals rich in Potassium, such as mica, the amount of shale could be overestimated. Another example is a fractured formation with uranium salts deposited in the fractures. Such a formation would give a high gamma ray response even if no shale is present. By removing the contribution of Uranium from the overall radioactivity reading, a much more accurate shale volume estimation can be derived (Ellis and Singer, 2008).

3.4.1.3. Shale volume from neutron-density

Another common method for calculating shale volume considers the separation between neutron porosity and bulk density logs. On a neutron-density curve combination, shale is recognised from the large positive separation, which occurs due to the
high hydrogen index of shale matrix material (Figure 3.6 a). As the volume of quartz grains in the shale increases, the neutron reading rapidly decreases. The density log curve, however, does not show such a strong change, since the matrix density of shales is similar to that of quartz. Curve separation decreases with increasing volume of quartz until it becomes slightly negative in a clean sand formation (assuming that the logging tool is calibrated against a clean limestone). The relationship is progressive and can be considered as being linear (Rider and Kennedy, 2011).

A common method to calculate the shale volume is by using the bulk density versus neutron porosity crossplot. The interpreter defines a ‘clean line’ and a ‘clay point’. The clay volume is then derived from the distance the input data falls between the two (Figure 3.6 b). The following equation was used for determining shale volume from the density versus neutron porosity crossplot:

\[
V_{\text{shND}} = \frac{(D_{C12} - D_{C11}) \times (N - N_{CI1}) - (D - D_{C11}) \times (N_{Cl2} - N_{CI1})}{(D_{C12} - D_{C11}) \times (N_{Clay} - N_{CI1}) - (D_{Clay} - D_{C11}) \times (N_{Cl2} - N_{CI1})}
\]  

(3.4.1.2)

where, \(D_{C11}, N_{CI1}\) and \(D_{C12}, N_{Cl2}\) – represent the selected values for the two ends of the clean line; \(D_{Clay}, N_{Clay}\) – are the density and neutron values for the shale point; and \(D, N\) – are the measured density and neutron values.

Shale volume estimation from the density-neutron crossplot results are presented in Table 3.6.
Table 3.6: Average estimated shale volume from the neutron-density method, together with coordinates for the clean sand line and clay point

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Clean line</th>
<th>Shale point</th>
<th>$V_{sh}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Stø</td>
<td>(-0.03,2.64;0.38,1.91)</td>
<td>(0.38,2.66)</td>
<td>0.11</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>(-0.03,2.64;0.38,1.91)</td>
<td>(0.35,2.65)</td>
<td>0.55</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>(-0.03,2.64;0.38,1.91)</td>
<td>(0.38,2.66)</td>
<td>0.69</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Stø</td>
<td>(-0.03,2.64;0.34,1.88)</td>
<td>(0.36,2.63)</td>
<td>0.09</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>(-0.03,2.64;0.38,1.90)</td>
<td>(0.31,2.62)</td>
<td>0.49</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>(0.38,2.66)</td>
<td>(0.38,2.66)</td>
<td>0.49</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Stø</td>
<td>(-0.02,2.65;0.41,1.91)</td>
<td>(0.42,2.63)</td>
<td>0.33</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>(-0.02,2.65;0.43,1.89)</td>
<td>(0.46,2.66)</td>
<td>0.54</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>(-0.02,2.65;0.41,1.90)</td>
<td>(0.39,2.65)</td>
<td>0.62</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Stø</td>
<td>(-0.03,1.55;0.07,2.27)</td>
<td>(0.39,2.59)</td>
<td>0.29</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>(-0.03,2.64;0.35,1.76)</td>
<td>(0.39,2.59)</td>
<td>0.50</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>(-0.03,2.64;0.34,1.98)</td>
<td>(0.27,2.64)</td>
<td>0.61</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Stø</td>
<td>(-0.03,2.64;0.18,2.27)</td>
<td>(0.24,2.63)</td>
<td>0.26</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
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<td>(0.24,2.63)</td>
<td>0.46</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>(-0.03,2.64;0.18,2.27)</td>
<td>(0.24,2.63)</td>
<td>0.68</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Stø</td>
<td>(0.38,2.66)</td>
<td>(0.40,2.67)</td>
<td>0.54</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>(-0.03,2.64;0.38,1.90)</td>
<td>(0.50,2.68)</td>
<td>0.67</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>(-0.03,2.64;0.27,2.13)</td>
<td>(0.42,2.62)</td>
<td>0.47</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Stø</td>
<td>(-0.02,2.65;0.31,2.05)</td>
<td>(0.42,2.61)</td>
<td>0.41</td>
</tr>
<tr>
<td></td>
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<td>(0.37,2.64)</td>
<td>0.58</td>
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<tr>
<td></td>
<td>Kobbe</td>
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<td>(0.41,2.61)</td>
<td>0.36</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Stø</td>
<td>(-0.02,2.65;0.41,1.91)</td>
<td>(0.41,2.63)</td>
<td>0.42</td>
</tr>
</tbody>
</table>

This method is strictly only accurate in brine saturated shaly sand formations where there is a mix between quartz and clay particles. If other sand forming minerals are present, some of the log separation may be caused by these minerals (Crain, 2016). In addition, gas or light oil saturation tends to reduce both the density and estimated neutron porosity, dragging data points toward the upper left side in the density versus neutron porosity plot.

3.4.1.4. Combination of shale volume curves

Having evaluated the shale method by the various methods described above, the linear shale volume equation and the shale volume estimation from the neutron-density crossplot seemed to agree best in most cases. However, the individual methods tend to err on the high side. As previously discussed, the linear gamma ray method overestimates the shale volume when the density of the shales is significantly higher than the sands. The neutron-density method will also overestimate the shale volume when heavy minerals are present. Individual methods may also err on the low side. In a bad borehole, the recorded density will be much lower than true density, which gives the effect of showing much lower shale volume in the neutron-density crossplot. The
presence of gas will also affect the neutron-density crossplot in a way that the shale volume will be underestimated (Kennedy, 2015).

To account for these effects, a slightly more elaborate method was chosen for final evaluations of shale volume. To avoid overestimations, the minimum value of the two methods (linear gamma ray and neutron-density methods) was taken at each depth point. Underestimations were accounted for by only using the gamma ray method in bad borehole intervals and in intervals containing gas.

3.4.1.5. Uncertainties in shale volume estimations

The major uncertainties associated with shale volume estimations from the gamma ray method are:

- The estimation of shaliness of a formation is subject to some confusion arising from two sources: (i) the persistent use of the terms *shale* and *clay* interchangeably, as described in Section 3.4.1; and (ii) the fact that it is the concentrations of certain radioactive isotopes and not the presence of shale or clay, that affects the gamma ray log response (see also section 3.4.1.1 (Ellis and Singer, 2008)).

- The gamma ray response may be lower where the logging tool is not in contact with the borehole wall (bad borehole) and, if possible, should be corrected using the caliper log (Mondol, 2015).

- High density drilling muds (such as barite based muds) may attenuate gamma ray signature, resulting in underestimation of shale volume, while potassium chloride based muds contribute to the overall radioactivity, resulting in overestimation (Mondol, 2015).

- Lithologies other than shale may sometimes have increased levels of gamma radioactivity. Uranium may be present in coals, dolomites and sandstones while sandstones and carbonates may contain potassium bearing minerals. Spectral gamma ray logging can be used for identifying such anomalies, as described in section 3.4.1.2 (Mondol, 2015).

The major uncertainties associated with shale volume estimations from the neutron-density method are:

- A particular separation between the neutron and density curves does not have a unique solution. For example, the two curves showing no separation may indicate a clean limestone or a shaly sandstone, which has just the right amount of shale for no separation to occur. Other log data must always be used to aid the interpretation (Rider and Kennedy, 2011).

- The method strictly only works in an oil or water saturated shaly quartz sands. Sandstones containing other (denser) minerals than quartz will cause excess separation between the curves. In the case of dolomite, anhydrite or gas zones, separation of the curves is not a function of shale (Crain, 2016).
3.4.2. Lithology determination

The concept of lithology is seemingly simplistic at first thought, however, it may have quite different meaning to different specialists. The petrophysicist needs a numerical representation of lithology, commonly only over the reservoir sections, for the purpose of eliminating its effects on calculations. The geologist requires a summary of lithology over the whole well in order to interpret the depositional environment, sequence formation, etc., and to build a geological model. A seismic geophysicist is interested in lithology mainly as far as it affects the density, compressional- and shear-wave velocities and the main boundaries or surfaces at which these parameters have a significant change (Rider and Kennedy, 2011).

Figure 3.7: Example of simple lithology estimation over an interval in the Fruholmen Formation in well 7226/2-1. 3 lithology types are used: sandstone, silt and clay. MDKB – measured depth from Kelly Bushing; RDEP – deep resistivity; RMIC – microresistivity; RwApp – apparent water resistivity; RmfApp – apparent mud filtrate resistivity; PHIT – total porosity; PHIE – effective porosity.

The major reason for performing a petrophysical analysis is to determine the presence and volume of hydrocarbons in the subsurface. This requires the calculation of porosity and water saturation and therefore the well logs were developed that are sensitive to these parameters. However, the effect of lithology on the well logs must first be evaluated. An example is that of porosity determination from the density log.
In order to compute porosity from the density log, a numerical representation of lithology must be known, that is, the density of the matrix and that of the saturating fluid (Rider and Kennedy, 2011; Ellis and Singer, 2008).

If the lithology within a studied interval is relatively simple, such as in a varying sandstone-shale ratio case, discriminating between the two can be relatively simple. As mentioned earlier, the gamma ray and the neutron-density methods can be used to identify the volume of shale. The two methods compliment each other and their combination helps reduce some of the inherent uncertainties. If the remaining volume of the rock (excluding porosity and fluids) is considered to be quartz sandstone, the interpretation process becomes simple. An example of this type of simple interpretation of lithology together with other reservoir parameters is shown in Figure 3.7.

If, however, complex mixtures of lithologies (such as a shale-sandstone-limestone or other scenarios) or complex mineralogy is present, the interpretation process may become challenging. Core sample, cuttings and equivalent outcrop study can be very helpful for the identification of lithology and mineralogy types, but are not always available. Techniques such as the ‘M-N plot’, ‘MID (matrix identification) plot’ and the incorporation of the PEF (photoelectric factor) log, attempt to remove the effects of porosity and deduce matrix parameters (Ellis and Singer, 2008).

### 3.4.3. Porosity estimation

Porosity can be described as the ratio of pore volume to bulk volume or the volume fraction of fluids within the rock. This, however, is a simplistic explanation, which causes some problems when dealing with real rocks with water in the pore space. Water may form weak chemical bonds with the surfaces of some minerals, especially clay minerals, resulting in grains being surrounded by a strongly adhering film of water. The morphology of clays also results in a high surface area, allowing them to bind relatively large amounts of water. As this water does not move under natural conditions, it may be considered as being part of the matrix. This leads to two rival ways of describing porosity: *total* and *effective* (Kennedy, 2015).

![Figure 3.8: Definition and relative amounts of the various volumes V, as used by well log interpreters. The subscripts ma = matrix, dcl = dry clay, cl = wet clay, cbw = clay boundwater, cap = capillary bound (irreducible) water, fw = free water, hyd = hydrocarbon, b = bulk, p = porosity, e = effective and t = total (from Ellis and Singer, 2008).](image)

The term *total porosity* simply refers to the total non-solid space. *Effective porosity,
on the other hand, disregards bound water and considers it as being part of the rock matrix. The latter may have slightly varying definition, depending on the user. For log analysts, effective porosity is the total porosity less clay bound water, whereas production engineers also exclude capillary-bound and isolated water, as these do not contribute to production (Ellis and Singer, 2008). Figure 3.8 summarizes the definition of various volumes used by log analysts.

There are no logs which measure porosity directly, however, it can be estimated either from sonic, neutron, density, or nuclear magnetic resonance (NMR) logs. The sonic log uses acoustic measurements, while the neutron, density, and NMR logs use nuclear measurements (Mondol, 2015). The basic principles and uncertainties of the porosity logs used in this thesis, namely sonic, neutron, and density, are discussed in the following sections.

3.4.3.1. Density Porosity

The density tool emits a continuous beam of high energy gamma rays into a formation, some of which are scattered back to a pair of gamma ray detectors. As the gamma rays collide with electrons in the formation, energy from the gamma-ray particles is lost. Gamma rays returning to the detectors are measured at two different energy levels. The interactions in the lower energy range depend on photoelectric scattering and produces the photoelectric factor (PEF) log, which may be used for lithology discrimination. The count of higher energy gamma rays, affected by Compton scattering, is proportional to the electron density of the formation, which, in turn, is related to formation bulk density through a constant (Asquith and Krygowski, 2004; Rider and Kennedy, 2011).

The bulk density of a formation is a function of matrix density, porosity and the density of the pore-filling fluid. Density porosity can then be calculated using the formula (Rider and Kennedy, 2011):

\[
\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}}
\]  

(3.4.3.1)

Where, \(\phi_D\) – density derived porosity; \(\rho_{ma}\) – matrix density; \(\rho_b\) – formation bulk density; \(\rho_{fl}\) – fluid density

The values for the matrix and fluid densities are chosen by the geoscientists. It is clear that by choosing different values, one can easily over- or underestimate the porosity. Matrix density values have a wider range than fluid density values and therefore the choice of matrix density has a larger impact on the calculated porosity (Asquith and Krygowski, 2004). Other uncertainties of estimating porosity from the density log are:

- **Heavy Minerals.** When bulk density is greater than the chosen matrix density, the calculated density porosity will have a negative value. This may be a good indication of heavy minerals within the formation, which have not been accounted for (Asquith and Krygowski, 2004).

- **Gas effect.** Gas can significantly affect the density porosity. Due to gas having a very low density, where invasion of a formation is shallow, the calculated density
porosity will be greater than true porosity (Asquith and Krygowski, 2004).

3.4.3.2. Effect of shale volume

When estimating porosity from the density log, the matrix density is often assumed to be constant throughout the interval of interest. The accuracy of this assumption depends on the types and distribution of various minerals. It is also common to account for clay minerals, because (i) shale volume is often estimated as part of well log analysis; (ii) clay minerals often have high densities and therefore are likely to shift the overall grain density significantly; and (iii) clays may contain significant amounts of water as part of their structure, which needs to be accounted for to estimate the effective porosity (Kennedy, 2015).

Including the shale volume term into Equation 3.4.3.1 gives:

\[
\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} - \frac{V_{sh}(\rho_{ma} - \rho_{sh})}{\rho_{ma} - \rho_{fl}}
\] (3.4.3.2)

where, \(\phi_D\) – density derived porosity; \(\rho_{ma}\) – matrix density; \(\rho_b\) – formation bulk density; \(\rho_{fl}\) – fluid density; \(V_{sh}\) – shale volume; \(\rho_{sh}\) – shale density.

If the wet shale density is selected as input for the shale density (\(\rho_{sh}\)), then the effective porosity is calculated. If the dry shale density is selected as input, then the total porosity is calculated. It is much easier to determine the wet shale density by reading the value from the logs, therefore effective porosity is commonly calculated first and total porosity second (Kennedy, 2015).

Even more elaborate equations exist, which attempt to reduce the effect of hydrocarbon effects on porosity estimation. One such equation is presented below:

\[
\phi_{De} = \frac{\rho_{ma} - \rho_b - V_{cl} \times (\rho_{ma} - \rho_{cl})}{\rho_{ma} - \rho_{fl} \times S_{XO} - \rho_{HyAp} \times (1 - S_{XO})}
\] (3.4.3.3)

where, \(\phi_{De}\) – effective density porosity, \(\rho_{ma}\) – matrix density, \(\rho_b\) – log reading of the bulk density, \(V_{cl}\) – wet clay volume, \(\rho_{cl}\) – wet/dry clay density, \(\rho_{fl}\) – filtrate density, \(\rho_{HyAp}\) – apparent hydrocarbon density, \(S_{XO}\) – flushed zone water saturation.

3.4.3.3. Neutron Porosity

Neutron logging tools create neutrons by means of a chemical source, which are then sent into a formation and the number of neutrons that are scattered back towards the tool is measured. Upon collision with the nuclei of the formation, the neutrons lose some of their energy. With enough collisions, the neutron is absorbed by a nucleus and a gamma ray is emitted. The hydrogen atom, due to its mass being almost equal to the mass of the neutron, is very efficient at absorbing these neutrons. Thus, the neutron log, in principle, measures the amount of hydrogen atoms within a formation. Since hydrogen within a formation is often in the form of water or hydrocarbons and tends to occur in pore spaces, the correlation between neutron count and porosity can be made (Asquith and Krygowski, 2004; Rider and Kennedy, 2011).

The measure of porosity is expressed mathematically as (Rider and Kennedy, 2011):
\[
\log_{10} \varnothing = aN + B \quad (3.4.3.4)
\]

where, \( \varnothing \) is the true porosity, \( a \) and \( B \) are constants, and \( N \) is the neutron tool count rate.

Neutron tools are usually calibrated against a clean, fresh water filled limestone, in which case the neutron porosity is equal to the true porosity. In all other cases, the neutron log value must be corrected for (Rider and Kennedy, 2011). Uncertainties associated with the porosity estimation from the neutron log are:

- **Hydrocarbon effects.** Many oils have a very similar hydrogen index to water, therefore the relationship between neutron log porosity and true porosity in a clean formation holds. However, in the presence of gas, the neutron porosity will underestimate the true porosity, as gas has a very low density and therefore a lower hydrogen index than water or oil. The same effect may occur in the presence of heavy oil, as it contains a lot of unsaturated compounds, which have a much lower hydrogen index than light oils (Rider and Kennedy, 2011).

- **Shale effect.** There are several ways in which the presence of shale affects the log reading. The most important is the fact that clay minerals contain a significant amount of hydrogen as part of their crystal structure. Some admixture of clay in the reservoir matrix will therefore affect the neutron porosity, leading to overestimations of porosity. Other causes include the higher density of most dry clay minerals, compared with limestone or sandstone and the fact that thermal neutron absorbers are more common in shales than other lithologies. Both these factors cause higher absorption of neutron rays and overestimation of neutron derived porosity (Rider and Kennedy, 2011).

More elaborate equations exist, which attempt to address some of the uncertainties associated with the porosity estimations from the neutron tool. An example of one such equation is given below:

\[
\phi_N = \frac{\phi_{\text{neu}} - V_{\text{cl}} \times \text{NeuCL} + \text{NeuMatrix}}{S_{\text{x0}} + (1 - S_{\text{x0}}) \times \text{NeuHyHI}} \quad (3.4.3.5)
\]

where, \( \phi_N \) – corrected neutron porosity; \( \phi_{\text{neu}} \) – neutron porosity reading; \( \text{NeuCL} \) – neutron log reading in wet clay; \( \text{NeuMatrix} \) – neutron reading in specific mineral matrix being studied (dependent on the matrix density and the mineral model); \( S_{\text{x0}} \) – flushed zone water saturation; \( \text{NeuHyHI} \) – apparent neutron reading in hydrocarbons (attempts to correct for the hydrocarbon effect).

Elaborate equations like Equation 3.4.3.3 and Equation 3.4.3.5 include additional parameters, which attempt to reduce some of the inherent uncertainties. However, it is important to understand that this introduces additional complexity, which, if not properly understood, may lead to errors in the interpretation. In this study, both simplistic and more elaborate equations were attempted and compared for both the neutron and density porosity methods. Results are presented in Table 3.7.
3.4.3.4. Porosity from neutron-density combination

Since neutron logs have many peripheral sensitivities and rarely measure porosity, the log is almost exclusively used, in open hole conditions, together with a density log (Ellis and Singer, 2008).

The neutron density combination may provide a value for porosity, largely free of lithology effects. Since porosity derived from each log suffers from uncertainties related to the lithology, by averaging both results, the lithological effects can cancel out (Mondol, 2015). The following equation is often used:

$$\phi = \sqrt{\frac{\phi_N^2 + \phi_D^2}{2}}$$

(3.4.3.6)

where $\phi_N$ and $\phi_D$ are neutron and density porosities, respectively.

Table 3.7: Average formation porosities, estimated using the various methods. $\phi_{Ds}$ – simple density porosity (assumes matrix density of 2.65 g/cm$^3$ and fluid density of 1.025 g/cm$^3$); $\phi_{Dt}$ – total density porosity; $\phi_{De}$ – effective density porosity; $\phi_N$ – neutron porosity reading; $\phi_{Nt}$ – total neutron porosity (Equation 3.4.3.5, without the clay term); $\phi_{Ne}$ – effective neutron porosity (Equation 3.4.3.5); $\phi_{NDt}$ – total porosity from neutron-density combination; $\phi_{NDe}$ – effective porosity from neutron-density combination.

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3.4.3.5. Sonic Porosity

Sonic tools consist of one or more transmitters and receivers a known distance apart. The tools measure the interval transit time (or slowness) of a sound wave, travelling through a formation along the axis of a borehole. This quantifies the formation’s ability to transmit sound waves. Three types of acoustic waves can be detected in borehole logging: the compressional wave, the shear wave and the Stoneley wave (Asquith and Krygowski, 2004; Rider and Kennedy, 2011).

The sonic log can be used to calculate porosity, however, other logs are preferred. Therefore, sonic porosity is normally used when no alternative exists, for example, when borehole conditions are poor (Rider and Kennedy, 2011).

Empirical and semi-empirical relationships are used for linking compressional wave interval transit time with porosity. One of the simplest examples is the semi-empirical equation known as the Wyllie time average equation (Wyllie et al., 1956):

\[ \phi_S = \frac{\Delta t - \Delta t_{ma}}{\Delta t_{fi} - \Delta t_{ma}} \]  

(3.4.3.7)

Where \( \phi \) – porosity; \( \Delta t \) – measured compressional slowness; \( \Delta t_{ma} \) – compressional slowness of the matrix; \( \Delta t_{fi} \) – compressional slowness of the interstitial fluid.

The Wyllie time average equation gives good results in a wide range of reservoirs. It typically works best in lower porosity, well cemented sands, but nearly always strongly overestimates porosity in highly porous unconsolidated sands. In such case, an empirical compaction factor can be added to the equation (Rider and Kennedy, 2011):

\[ \phi_S = \frac{\Delta t - \Delta t_{ma}}{\Delta t_{fi} - \Delta t_{ma}} \times \frac{1}{C_p} \]  

(3.4.3.8)

Where, \( C_p \) – compaction factor

Many alternatives to this simple relationship have been proposed, ranging from small modifications to different models altogether. It is safe to say that no universal relationship exists between porosity and slowness and that, over a limited range of porosities, the Wyllie time average equation can always be calibrated to produce satisfactory results (Rider and Kennedy, 2011).

Similarly, shear wave interval transit time may be used for calculating sonic porosity. Although not widely accepted, this has the advantage of being little affected by the presence of gas (Rider and Kennedy, 2011). As proposed by Perarnau and Payne (2006), the relationship between shear wave slowness and porosity, although not linear, can be approximated as such below 36% porosity using the following equation:

\[ \Delta t_{shear} = 2.72\phi + \Delta t_{solid} \]  

(3.4.3.9)

Where \( \Delta t_{shear} \) – shear wave slowness; \( \phi \) – porosity; \( \Delta t_{solid} \) – compressional slowness of the matrix.

A practical application of this equation is as a gas indicator. When gas is present, shear wave velocity should increase, compared with the same rock saturated with
water. Therefore porosity calculated using equation 3.4.3.9 will be underestimated. Compressional wave velocity, on the other hand, has been observed to decrease with the presence of gas. Therefore, porosities estimated by both methods in water filled sands should agree, and they should separate in gas filled sands (Perarnau and Payne, 2006). According to Rider and Kennedy (2011), such an approach is increasingly used to demonstrate the presence of gas at low saturations, too low to be detected by other logs, such as neutron or resistivity.

3.4.4. Water saturation and pay zone identification

Water saturation is defined as the portion of the pore space occupied by water, expressed as either a fraction or a percentage. Clay bound water is not included in this definition, so corrections must be made if shale is present. Log-derived saturation is most often based on the resistivity log. Other logs that can be used for calculating water saturation are pulsed neutron logs, the combination of density logs with the hydrogen index from NMR or neutron logs (Ellis and Singer, 2008; Crain, 2016; Kennedy, 2015).

Ellis and Singer (2008) describe the determination of water saturation and permeability as the most valuable, but also most difficult outputs of log interpretation. To estimate saturation from resistivity logs, Archie’s equation Archie (1942), or one of its modifications, is most often used. The general form of this equation is as follows:

\[ S_w = \frac{a}{\sqrt[n]{\phi^m \times \frac{R_w}{R_t}}} \]  

(3.4.4.1)

Where, \( S_w \) – water saturation; \( \phi \) – porosity; \( R_w \) – formation water resistivity; \( R_t \) – observed bulk resistivity; \( a \) – tortuosity factor; \( m \) – cementation exponent; \( n \) – saturation exponent.

Archie’s equation works well in rocks with simple, uniform pore systems, filled with saline water, but is not directly applicable to shaly or heterogeneous formations Ellis and Singer (2008). In shaly formations, corrections for clay bound water must be made. In this study, the water saturation was calculated from the effective porosity and the resistivity logs.

There are quite a few variables in Equation 3.4.4.1, which have to be determined. The most important are the porosity \( \phi \) and the resistivity of the formation water \( R_w \). Estimation of porosity has been discussed in the previous sections and, in this study, the effective porosity from the neutron-density log combination has been chosen to be most representative of the true porosity. The other variables are discussed below:

- **Water resistivity** \( R_w \). In the absence of formation water samples, water resistivity is most commonly determined from the Pickett plot (Cannon, 2015). The use of the plot is explained in some detail in the following section.

- **Cementation exponent** \( m \) expresses the effect of the pore network on resistivity. The exponent is commonly assumed not to be dependent on temperature. Typical values are: around 1.3 for unconsolidated sands, and 1.8 – 2.0 for consolidated sandstones (Mondol, 2015).
Saturation exponent $n$ is related to the wettability of the rock and expresses the dependency of resistivity on the presence of non-conductive fluid. Water wet rocks are more conductive due to a continuous film of water along the pore walls, while oil wet rocks will have higher resistivity. A typical value for most cases is 2 (Mondol, 2015). However, this value applies to a water wet case. In oil wet rocks, resistivity increases sharply when even small amounts of oil are introduced. This can give a saturation exponent value much larger than 2. An irregular mixture of different sized pores can also give $n$ values that are not equal to 2. This is because oil and gas can displace water much easier in some types of pores than others (Ellis and Singer, 2008).

Tortuosity factor $a$ is related to the flow area difference between pore throat and pore body, with common values of around 1.

### 3.4.4.1. Identification of parameters for the Archie equation

A common method for estimating resistivity of the formation water $R_w$ and $m$ is by using the Pickett plot, which is a graphical representation of the Archie equation (Figure 3.9). To produce the plot, the Archie equation is first rearranged to produce the following:

$$\log(\phi) = -\frac{1}{m} \log(R_t) - n \log(S_w) + \log(a \times R_w)$$

When making the actual plot, the resistivity is now plotted against porosity, both on logarithmic scales. In theory, this should produce linear arrangements of the data.
so that resistivity increases with decreasing porosity. Returning to Equation 3.4.4.2, the terms \( \log(\phi) \) and \( \log(R_t) \) form the y and x axes, respectively. The term \( -\frac{1}{m} \) determines the slope of the line, while the term \( -n \log(S_w) \) produces a family of lines, from which information about saturation can be discerned. Finally, the term \( \log(a \times R_w) \) gives us information about the formation water resistivity.

Table 3.8: Average water saturation for the different formations. m – cementation exponent, n – saturation exponent, a – tortuosity factor, Sw – average water saturation.

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Rw</th>
<th>m</th>
<th>n</th>
<th>a</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Stø</td>
<td>0.12</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>0.25</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>0.25</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Stø</td>
<td>0.12</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>0.17</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Stø</td>
<td>0.08</td>
<td>1.9</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>0.14</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>0.14</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Stø</td>
<td>0.09</td>
<td>1.9</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>0.11</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>0.11</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Stø</td>
<td>0.07</td>
<td>1.9</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>0.11</td>
<td>1.9</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>0.11</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Stø</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>0.09</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>0.09</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Stø</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>0.06</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>0.06</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Stø</td>
<td>0.05</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>0.04</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Kobbe</td>
<td>0.04</td>
<td>2.0</td>
<td>2</td>
<td>1</td>
</tr>
</tbody>
</table>

The advantage of the plot is that it allows the determination of water saturation directly, without the knowledge of \( R_w \) or \( m \). The plot also predicts the mentioned variables, giving a value for \( R_w \) at reservoir conditions, which does not require any temperature corrections. Several important negative issues with the plot, that should be mentioned, are: (i) the intercept is actually a product of \( aR_w \), as seen in Equation 3.4.4.2. For the technique to work, variable \( a \) must either be known, or assumed as having a certain value (usually 1); (ii) All of the uncertainties arising from the estimation of porosity are involved here, as porosity is an important input in the equation; and (iii) in real world scenarios, the data points most often do not form a straight line, but rather a cloud around the linear trend. In practice, the \( R_w \), or, more precisely, \( aR_w \) is found by cross plotting deep resistivity tool readings against porosity and forcing a best fit straight line through the data points (Kennedy, 2015). Parameters for the
3.4.5. Net-to-Gross ratio and petrophysical cut-offs

The purpose of the term ‘net-to-gross (NTG)’ is to define the productive zones within a hydrocarbon reservoir. As with many other important concepts, the term may easily be misunderstood when used between different specialists and for different purposes. Errors sometimes arise from the misuse of the term ‘net’ as understood by different discipline groups. While geologists may think in terms of net sand, petrophysicists may think of net reservoir and reservoir engineers – net pay (Ringrose, 2008). The description of the different terms is given in Table 3.9.

Table 3.9: Definitions of net properties. From Worthington and Cosentino (2005).

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross rock</td>
<td>All rocks within the evaluation interval.</td>
</tr>
<tr>
<td>Net sand</td>
<td>A lithologically clean sedimentary rock (commonly defined by a log-derived $V_{sh}$ cutoff).</td>
</tr>
<tr>
<td>Net reservoir</td>
<td>Net sand intervals with useful reservoir properties (commonly defined by a log-derived porosity cutoff).</td>
</tr>
<tr>
<td>Net pay</td>
<td>Net reservoir intervals containing hydrocarbons (commonly defined by a log-derived saturation cutoff).</td>
</tr>
<tr>
<td>N/G ratio</td>
<td>Should always be defined with reference to one of the ‘net’ terms above. It is the ratio of net thickness to gross thickness and has a value between 0 and 1.</td>
</tr>
</tbody>
</table>

‘Petrophysical cutoffs’ are limiting values used in expressing the NTG ratio. The adoption of the terms described in Table 3.9 require three physical cutoffs: shale volume $V_{sh}$, porosity $\phi$, and water saturation $S_w$. The cutoffs may either be considered on their own to evaluate hydrocarbons in place, or can be linked to another parameter, such as permeability. The latter case is more appropriate for the dynamic estimation of the of the ultimate hydrocarbon recovery through simulation. The two approaches will lead to different estimations of net pay which may or may not be similar (Worthington and Cosentino, 2005).

Another important thing to consider is minimum net-pay thickness. All well logs have a certain resolution which is defined as the minimum layer thickness for which a log will record a correct parametric value. A nominal value is 0.6 m, but may vary from log to log. This calls for a minimum thickness for a net-pay interval to be admissible and has a common range of 0.25 - 1.0 m (Worthington and Cosentino, 2005).

Worthington and Cosentino (2005) argue for cutoffs to be fit for purpose and be selected according to, among other things, intended deliverable, flow regime, reservoir recovery mechanism and stage of depletion. However, such sophisticated methods have been considered beyond the scope of this project. Instead, proposed cutoff values have been used (see Table 3.10). A medium value was taken for each parameter. Permeability has not been evaluated in this study, therefore the cutoff values have not been linked to this property. Evaluations of the net sand to gross and net reservoir to
gross fractions for the studied formations is presented in Table 3.11.

**Table 3.10:** Proposed cutoff values for calculating hydrocarbons in place for sandstones. Modified from (Worthington and Cosentino, 2005).

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Cutoff parameter</th>
<th>Range of values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstones</td>
<td>$V_{sh}$</td>
<td>0.3 – 0.5</td>
</tr>
<tr>
<td></td>
<td>$\phi$</td>
<td>0.06 – 0.08</td>
</tr>
<tr>
<td></td>
<td>$S_w$</td>
<td>0.5 – 0.6</td>
</tr>
</tbody>
</table>

**Table 3.11:** Various net-to-gross fractions for the Stø, Snadd and Kobe Formations. $S,s$ – sand; $R,r$ – reservoir; $P$ – pay.

<table>
<thead>
<tr>
<th>Well</th>
<th>FM</th>
<th>Gross</th>
<th>Net S</th>
<th>Net R</th>
<th>Net P</th>
<th>N(s)/G</th>
<th>N(r)/G</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Sto</td>
<td>16</td>
<td>16</td>
<td>16</td>
<td>–</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Sto</td>
<td>17</td>
<td>16</td>
<td>16</td>
<td>16</td>
<td>0.96</td>
<td>0.95</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Sto</td>
<td>8</td>
<td>7</td>
<td>7</td>
<td>0</td>
<td>0.91</td>
<td>0.91</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Sto</td>
<td>43</td>
<td>30</td>
<td>28</td>
<td>23</td>
<td>0.70</td>
<td>0.66</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Sto</td>
<td>61</td>
<td>28</td>
<td>27</td>
<td>0</td>
<td>0.46</td>
<td>0.44</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Sto</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Sto</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Sto</td>
<td>25</td>
<td>13</td>
<td>13</td>
<td>0</td>
<td>0.54</td>
<td>0.54</td>
</tr>
<tr>
<td>7324/7-1S</td>
<td>Snadd</td>
<td>1167</td>
<td>298</td>
<td>278</td>
<td>26</td>
<td>0.26</td>
<td>0.24</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Snadd</td>
<td>157</td>
<td>54</td>
<td>53</td>
<td>0</td>
<td>0.35</td>
<td>0.34</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Snadd</td>
<td>1001</td>
<td>304</td>
<td>301</td>
<td>39</td>
<td>0.30</td>
<td>0.30</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Snadd</td>
<td>342</td>
<td>146</td>
<td>132</td>
<td>7</td>
<td>0.43</td>
<td>0.39</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Snadd</td>
<td>361</td>
<td>80</td>
<td>74</td>
<td>0</td>
<td>0.22</td>
<td>0.21</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Snadd</td>
<td>642</td>
<td>291</td>
<td>281</td>
<td>7</td>
<td>0.45</td>
<td>0.44</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Snadd</td>
<td>376</td>
<td>149</td>
<td>137</td>
<td>0</td>
<td>0.40</td>
<td>0.36</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Snadd</td>
<td>915</td>
<td>627</td>
<td>399</td>
<td>?</td>
<td>0.69</td>
<td>0.44</td>
</tr>
<tr>
<td>7324/7-1S</td>
<td>Kobbe</td>
<td>472</td>
<td>64</td>
<td>58</td>
<td>2</td>
<td>0.14</td>
<td>0.12</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Kobbe</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Kobbe</td>
<td>665</td>
<td>93</td>
<td>85</td>
<td>33</td>
<td>0.14</td>
<td>0.13</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Kobbe</td>
<td>633</td>
<td>88</td>
<td>73</td>
<td>29</td>
<td>0.14</td>
<td>0.12</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Kobbe</td>
<td>624</td>
<td>89</td>
<td>82</td>
<td>29</td>
<td>0.14</td>
<td>0.13</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Kobbe</td>
<td>631</td>
<td>141</td>
<td>134</td>
<td>50</td>
<td>0.22</td>
<td>0.21</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Kobbe</td>
<td>201</td>
<td>50</td>
<td>48</td>
<td>0</td>
<td>0.25</td>
<td>0.24</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Kobbe</td>
<td>1136</td>
<td>560</td>
<td>294</td>
<td>?</td>
<td>0.49</td>
<td>0.26</td>
</tr>
</tbody>
</table>
3.5. Rock physics diagnostics

Rock physics provides the link between reservoir parameters, such as porosity, lithology, grain sorting, clay volume, water/hydrocarbon saturation, and seismic properties, such as bulk density, elastic moduli, acoustic impedance, $V_P/V_S$ etc. In other words – understanding the seismic-to-reservoir relationships. Rock physics models allow for the interpretation of observed seismic and/or sonic velocities to be interpreted in terms of the mentioned reservoir parameters or to predict the seismic response for certain scenarios, such as lithology or fluid substitution. Observed reservoir properties can also be used to predict the seismic properties (Avseth et al., 2009).

The rock physics interpretation follows the workflow: (i) first, the velocity-porosity trends are calculated for the expected lithologies and for various burial depths; (ii) next, the elastic bulk moduli of the brine- and hydrocarbon saturated rocks are calculated from the rock physics models; and (iii) finally, the various seismic parameters are used to construct rock physics templates which can then be used for predicting lithology, fluid type, cementation and sorting.

3.5.1. $V_S$ prediction

Shear wave information can be very important for the rock physics interpretation as it often allows interpreters to better separate the seismic signatures of lithology, fluid type and pore pressure (Avseth et al., 2005). A common problem is that the shear sonic data is often not acquired during well logging, which may be due to cost saving or other reasons. The importance of shear wave information has therefore led to many relations being developed to estimate $V_S$. Most of these relationships are empirical, derived for wet sediment and linked to $V_P$. Other relations also include consideration the effect of clay volume, porosity, fluid type, pressure etc. (Dvorkin, 2008). Some of the more well known relationships are listed in Table 3.12. The major limitation associated with such empirical relations is that they, strictly speaking, only apply to the set of rocks studied (Mavko et al., 2009).

<table>
<thead>
<tr>
<th>Author(s)</th>
<th>Description</th>
<th>Equation (in km/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Castagna et al. (1985)</td>
<td>Mudrock equation</td>
<td>$V_S = 0.862V_P - 1.172$</td>
</tr>
<tr>
<td>Castagna et al. (1993)</td>
<td>Clastic rock</td>
<td>$V_S = 0.804V_P - 0.856$</td>
</tr>
<tr>
<td>Krief et al. (1990)</td>
<td>Wet sand</td>
<td>$V_P^2 = 2.213V_S^2 + 3.857$</td>
</tr>
<tr>
<td>Krief et al. (1990)</td>
<td>Gas sand</td>
<td>$V_P^2 = 2.282V_S^2 + 0.902$</td>
</tr>
<tr>
<td>Krief et al. (1990)</td>
<td>Shaly sand</td>
<td>$V_P^2 = 2.033V_S^2 + 4.894$</td>
</tr>
<tr>
<td>Han et al. (1986)</td>
<td>Clay &lt;25%</td>
<td>$V_S = 0.754V_P - 0.657$</td>
</tr>
<tr>
<td>Han et al. (1986)</td>
<td>Clay &gt;25%</td>
<td>$V_S = 0.842V_P - 1.099$</td>
</tr>
<tr>
<td>Han et al. (1986)</td>
<td>Shaly sand, $\phi&lt;15%$</td>
<td>$V_S = 0.756V_P - 0.662$</td>
</tr>
<tr>
<td>Han et al. (1986)</td>
<td>Shaly sand, $\phi&gt;15%$</td>
<td>$V_S = 0.853V_P - 1.137$</td>
</tr>
<tr>
<td>Greenberg and Castagna (1992)</td>
<td>Sandstone</td>
<td>$V_S = 0.804V_P - 0.856$</td>
</tr>
<tr>
<td>Greenberg and Castagna (1992)</td>
<td>Shale</td>
<td>$V_S = 0.770V_P - 0.867$</td>
</tr>
</tbody>
</table>
In addition, Han et al. (1986) introduced linear equations which link both $V_P$ or $V_S$ to porosity and clay volume in sandstone, for different pressure values. Their samples ranged in $\phi$ from 2 to 30 percent, and clay volume from 0 to 50 percent, respectively. The authors also observed that velocities in clean sandstones were significantly higher than what was predicted by the linear relations, concluding that even small amounts of clay tend to significantly reduce the elastic moduli of sandstones. A selected part of their equations are presented in Table 3.13 below:

**Table 3.13**: Han et al. (1986) equations for consolidated sandstones (from empirical, ultrasonic lab measurements). $V_P$ and $V_S$ are in km/s; the total porosity is in fractions; Clay volume C is in fractions.

<table>
<thead>
<tr>
<th>Pressure</th>
<th>Saturation</th>
<th>$V_P$</th>
<th>$V_S$</th>
</tr>
</thead>
<tbody>
<tr>
<td>40 MPa</td>
<td>100% water</td>
<td>$V_P = 5.59 - 6.93\phi - 2.18C$</td>
<td>$V_S = 3.52 - 4.91\phi - 1.9C$</td>
</tr>
<tr>
<td>30 MPa</td>
<td>100% water</td>
<td>$V_P = 5.55 - 6.96\phi - 2.18C$</td>
<td>$V_S = 3.47 - 4.84\phi - 1.87C$</td>
</tr>
<tr>
<td>20 MPa</td>
<td>100% water</td>
<td>$V_P = 5.49 - 6.94\phi - 2.17C$</td>
<td>$V_S = 3.39 - 4.73\phi - 1.81C$</td>
</tr>
<tr>
<td>10 MPa</td>
<td>100% water</td>
<td>$V_P = 5.39 - 7.08\phi - 2.13C$</td>
<td>$V_S = 3.29 - 4.73\phi - 1.74C$</td>
</tr>
</tbody>
</table>

Shear wave velocity data was missing in wells 7324/10-1 and 7228/2-1S, and therefore had to be estimated. The concern here is determining which relation works best in this study area. Luckily, $V_S$ data is available in most of the wells in this study, allowing for estimation comparisons with real S-wave data.

To study the different $V_S$ estimations, $V_S$ was cross-plotted against $V_P$ for the Kobbe, Snadd and Stø Formations for the wells that had both velocities. Some of the well known published $V_P$-$V_S$ relations were then overlaid and compared with the relation obtained from linear regression (Figure 3.10). In order to avoid the effect of hydrocarbons on velocity, data points were filtered to include only water saturated data. The effect of shale was also taken into consideration by attempting linear regression for two scenarios: (i) where $V_{sh} \leq 0.5$; and (ii) where $V_{sh} > 0.5$. Results of the linear regression analysis are shown in Table 3.14.

**Table 3.14**: $V_P$-$V_S$ relations obtained from linear regression.

<table>
<thead>
<tr>
<th>$V_P$-$V_S$ relation (km/s)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$V_S = 0.610 \times V_P - 0.249$</td>
<td>$V_{sh} \leq 0.5$, $S_w = 1$</td>
</tr>
<tr>
<td>$V_S = 0.759 \times V_P - 0.884$</td>
<td>$V_{sh} &gt; 0.5$, $S_w = 1$</td>
</tr>
</tbody>
</table>

The basic limitation of the published relations is that they are empirical and therefore are strictly only applicable to the set of rocks from which they were derived. It is recommended that, if possible, empirical relations from the specific area being studied should be used (Li et al., 2007).

To better visualise how the different $V_S$ estimations compare in the sandstone intervals of the study area, they were plotted together with the measured $V_S$ over a brine saturated Snadd reservoir interval and a gas saturated Kobbe reservoir interval in well 7225/3-2 (Norvarg) (Figure 3.11).

When compared over a brine saturated sandstone interval, relationships by Krief et al. (1990) (for ‘wet sand’), Castagna et al. (1993) (clastic rock), and the relation by
Figure 3.10: Measured $V_P$-$V_S$ relations compared with $V_S$ determined from $V_P$ (using published relations) in sands and shaly sands (left), and sandy shales and shales (right) in well 7324/7-1S.

Figure 3.11: $V_S$ estimation from $V_P$ in the brine saturated reservoir interval in the Snadd Formation (left) and gas saturated (average $S_w = 0.51$) reservoir interval in the Kobbe Formation (right) in well 7225/3-2 (Norvarg).
linear regression were all observed to be very close to the measured $V_S$, while the ‘mudrock’ equation by Castagna et al. (1985) strongly underestimated $V_S$ over the sandstone, but showed close agreement in the underlying and overlying shales. All relations strongly underestimated $V_S$ over the gas saturated sandstone interval in the Kobbe Formation. This is caused by a significant decrease in $V_P$ due to the gas effect. Once again, it is important to note the strong effect of hydrocarbon on P-wave velocity. It is thus not recommended to attempt $V_S$ estimation from $V_P$ in hydrocarbon saturated zones, keeping in mind that the $V_S$ values may be strongly underestimated.

3.5.2. Rock physics diagnostics

The rock physics diagnostics technique uses velocity-porosity relations as a means to infer the microstructure and texture of rocks. The methods work by adjusting an effective-medium theoretical model curve to a trend in the data. The microstructure of the rock is then assumed to match that of the model. Estimations of the geometric details provided by the model can then be used to predict more exact seismic properties (Avseth et al., 2005).

3.5.3. Rock physics effective medium models

If the porosity, mineralogy and the elastic moduli of the constituent minerals for a certain rock are known, only the upper and lower bounds of seismic velocities can be predicted. In order to predict the seismic properties with a higher accuracy, the geometric details of how the grains and pores are arranged relative to one another within the rock volume must be known. Several models exist, which deal with the microstructure and texture of rocks. Such models also allow the prediction of the microstructure and texture of rocks from seismic velocity data (Avseth et al., 2010).

![Figure 3.12: Schematic illustration of three effective medium models for high porosity sands in the elastic modulus versus porosity domain, and corresponding diagenetic transformations (from Avseth et al., 2005).](image)

Sandstone microstructure and reservoir heterogeneity strongly affects the pore fluid sensitivity in reservoirs. It is therefore imperative that these geological factors are included in the rock physics analysis. Good local validation of the models can even
allow for the degree of sorting and cement volume to be quantified (Avseth et al., 2009).

A schematic representation of 3 commonly used effective medium models is given in Figure 3.12. Creation and use of these models are discussed in the following sections.

3.5.4. The friable sand model

The friable sand model was first introduced by (Dvorkin and Nur, 1996). The model describes the change in the velocity-porosity relation with deteriorating grain sorting. The model assumes that as sorting deteriorates, additional smaller grains are introduced into the pore space until the pore space is filled up.

Following the instruction by (Avseth et al., 2005), the friable sand model was produced for varying effective pressure values for the use in this study. The first step in producing the model involves computing the elastic moduli of the dry high-porosity end member. This can be achieved by using the Hertz-Mindlin theory (Mindlin, 1949). The theory assumes a random pack of identical spherical grains and takes confining pressure into consideration. The equations are presented below:

\[ K_{HM} = \left[ \frac{n^2(1 - \phi_c)^2 \mu^2 P}{18\pi^2 (1 - \nu)^2} \right]^{\frac{3}{2}} \]  \hspace{1cm} (3.5.4.1)

\[ \mu_{HM} = \frac{5 - 4\nu}{5(2 - \nu)} \left[ \frac{3n^2(1 - \phi_c)^2 \mu^2 P}{2\pi^2 (1 - \nu)^2} \right] \]  \hspace{1cm} (3.5.4.2)

where, \( K_{HM} \) – dry rock bulk modulus; \( \mu_{HM} \) – dry rock shear modulus; \( n \) – coordination number, which is defined as the number of contact points per grain; \( \phi_c \) – critical porosity; \( \mu \) – shear modulus of the grain (the solid phase); \( \nu \) – Poisson’s ratio of the solid phase; and \( P \) – effective pressure.

The coordination number \( n \) is related to porosity and can be approximated using the empirical equation (Avseth et al., 2005):

\[ n = 20 - 34\phi + 14\phi^2 \]  \hspace{1cm} (3.5.4.3)

Critical porosity \( \phi_c \) is the highest possible porosity at which the sedimentary grains stop behaving as a suspension and the grain skeleton becomes load bearing. For the same type of mineral grain, the initial critical porosity will depend on the grain size and shape. Many experiments have been carried out by various authors in order to model the experimental compression of loose sediments. In this study, initial critical porosity of well sorted medium grain size lithic sands from experimental results by Chuhan et al. (2003) has been taken to represent the highest porosity values at different pressure conditions.

The input for effective pressure was calculated from the average depth of the reservoir intervals, assuming a 10 kPa/m pressure gradient.
The Poisson’s ratio $\nu$ can be computed using the following equation:

$$\nu = \frac{3K - 2\mu}{2(3K + \mu)}$$  \hspace{1cm} (3.5.4.4)

where, the $K$ and $\mu$ are the bulk and shear moduli of the grain, respectively.

The model produced for this study assumed that all of the grains are quartz. The bulk and shear moduli of 37GPa and 44Gpa, respectively, were assumed for the quartz grains.

The elastic properties of the other ‘end member’ at zero porosity must have the properties of the mineral being modelled. The moduli of the sands in between the ‘end members’ (varying degrees of sorting) were then computed using the lower Hashin and Shtrikman (1963) bound. The dry bulk and shear moduli of the friable sand mixture could now be computed using the following equation:

$$K_{dry} = \left[ \frac{\phi/\phi_c}{K_{HM} + 4\mu_{HM}/3} + \frac{1 - \phi/\phi_c}{K + 4\mu_{HM}/3} \right]^{-1} - \frac{4}{3}\mu_{HM}$$  \hspace{1cm} (3.5.4.5)

$$\mu_{dry} = \left[ \frac{\phi/\phi_c}{\mu_{HM} + z} + \frac{1 - \phi/\phi_c}{\mu + z} \right]^{-1} - z$$  \hspace{1cm} (3.5.4.6)

where,

$$z = \frac{\mu_{HM}}{6} \left( \frac{9K_{HM} + 8\mu_{HM}}{K_{HM} + 2\mu_{HM}} \right)$$

Once the dry elastic moduli of the dry high-porosity end member were computed, fluid substitution was performed using Gassmann’s equation (Equation 3.6.5.1) and the elastic moduli computed for the fluid saturated case. Here, the unknown variable was the bulk modulus of the fluid. The value of 2.5 GPa was chosen to represent the bulk modulus of the saturating fluid (brine).

The final step in producing a usable model was computing the P- and S-wave velocities for the different porosities using the following equations:

$$V_P = \sqrt{\frac{K + 4/3 \times \mu}{\rho}}$$

$$V_S = \sqrt{\frac{\mu}{\rho}}$$

where, $\rho$ – bulk density.

The density of the quartz grain was chosen to be 2.65 g/cm$^3$ and 1.00 g/cm$^3$ for water. These values were used to compute the bulk density of the modelled rock for different porosities. Created model lines are presented in Figure 3.13.

The friable sand model describes the velocity-porosity behaviour as a function of sorting at a specific pressure for an unconsolidated sand. At any specific pressure value, the data points will plot along the model line, depending on the degree of sorting (Avseth et al., 2005).
3.5.5. The contact-cement model

The contact cement model shows the relationship between velocity and porosity at high porosities. Contact cements fills spaces near the grain contact points, rapidly stiffening the rock and eliminating the effect of effective pressure, with little associated change in porosity. The model represents a diagenetic trend for clean sands (Avseth et al., 2005).

3.5.6. The constant-cement model

The constant cement model shows the relationship between velocity and porosity versus sorting at a specific cement volume. For each model line, the assumption is made that the sands have a constant amount of contact cement, and the change in porosity is caused by sorting. The model is produced by using the contact cement model to calculate the velocity-porosity for a well sorted sandstone with a given cement volume. A lower bound is used to interpolate between this high porosity end member and zero porosity (Avseth et al., 2005).

Figure 3.13: Effective medium models used in this study. a) Burial, compaction and diagenesis move the data points off the suspension line. Sediments of constant age, but varying shaliness (sorting) will fall along the sorting trend lines (grey), while sediments of constant shaliness (sorting), but varying age will fall along the cementing trend lines (black). b) The amount of cement and degree of sorting can be estimated by observing where the data points plot. Results must be verified against thin section analysis (Avseth et al., 2009). Friable sand model lines have been computed in this study. The model lines in a) have been digitized from Avseth et al. (2005), while the model lines in b) have been digitized from Avseth et al. (2009). Note the difference between the friable sand model lines and the diagenetic trend line (black, solid) at 0% porosity in a) caused by different choice of elastic parameters and/or density of the mineral grain between the digitized model and the models from this study.
3.5.7. Construction of rock physics templates

The rock physics template (RPT) technique was introduced by Ødegaard and Avseth (2003), showing that the fluid and mineralogical content of a reservoir could be estimated by cross-plotting $V_P/V_S$ ratio against acoustic impedance.

Geological factors, such as lithology, mineralogy, burial depth, diagenesis, pressure and temperature must be taken into account when generating RPT’s for a specific basin (Avseth, 2015).

Before we can construct the various RPT’s it is necessary to calculate velocity-porosity trends for the expected lithologies and various burial depths (Avseth et al., 2005).

3.5.8. Vp/Vs versus AI

The rock physics template by Ødegaard and Avseth (2003) allows us to perform rock physics analysis using $V_P/V_S$ ratio and P-Impedance of various rock types based on their mineralogy, porosity, fluid type, pressure and grain contacts (Figure 3.14).

![Figure 3.14](image_url)

**Figure 3.14:** a) Generalised rock physics template, which includes porosity trends for different lithologies, and increasing gas saturation for sands (assuming uniform saturation). Black arrows show expected effects of various geologic trends: (1) increasing shaliness, (2) increasing cement volume, (3) increasing porosity, (4) decreasing effective pressure, and (5) increasing gas saturation (from Ødegaard and Avseth, 2004). b) Data points from the Kobbe Formation in well 7225/3-2 (Norvarg) in the $V_P/V_S$ versus AI domain. The sand model line used in the template was generated assuming a clean, uncemented, brine saturated quartz sandstone at 13.5 MPa effective pressure (computed from the average depth of the Kobbe sandstones in this well, assuming a 10 kPa/m pressure gradient).

The computation of the models used in the RPT involves four steps: (i) the dry rock frame moduli are computed for a given porosity/pressure using the Hertz-Mindlin contact theory; (ii) the dry rock frame moduli are computed over a range of porosities. Porosity reduction related to packing and sorting is modelled by the lower Hashin-Shtrikman bound. For cemented rocks, either the Dvorkin-Nur’s cement model or the Hashin-Shtrikman upper bound model is used; (iii) fluid substitution is carried out using the Gassmann’s equations. The dry rock properties computed from the
combined Hertz-Mindlin and Hashin-Shtrikman models are used as input and a uniform saturation is assumed; and (iv) $V_P$, $V_S$ and density are calculated for each scenario and then the acoustic impedance and $V_P/V_S$ ratio are cross-plotted (Avseth et al., 2005).

The template can be very useful for the purpose of discriminating lithology, porosity and saturation. It does not, however, include some geologic changes, such as cementation. Diagenetic quartz cement will have a tendency to move brine-saturated data points to an area of low $V_P/V_S$, closer to where hydrocarbon saturated points are expected to plot. The presence of shale in the sandstone will have an opposite effect and move data points toward the shale cluster. Both effects can work to counteract each other, i.e., if interbedded shale is soft compared to the sand, the net-to-gross effect will tend to decrease the effect of cement, dragging the points in the opposite direction in the $V_P/V_S$ versus AI crossplot (Avseth et al., 2009).

3.5.9. LambdaRho versus MuRho

Goodway (1999, 2001) proved that LMR parameters ($\lambda \rho$ and $\mu \rho$) are key lithology and fluid indicators in quantitative AVO interpretation.

![Figure 3.15: a) Conceptual LMR plot by Perez and Tonn (2003), showing trends for various lithologies, porosities, fluids and age of sediments (represented by different $V_P/V_S$ ratios). b) LMR plot with data points from the Kobbe Formation in well 7225/3-2, with threshold cutoff for porous gas sands](image)

The basic principle in distinguishing lithology and fluid type from the perspective of Lamé parameter perspective is by finding the ratio between incompressibility ($\lambda$) and rigidity ($\mu$). How the grains of a sedimentary rock are organised affects the distribution of the effective stress within the rock. In cases where the material has a higher incompressibility than rigidity ($\lambda > \mu$), an anisotropic distribution of stresses deforms the grain shape resulting in large aspect ratios. This is common in laminated shales. An even distribution of stress ($\lambda = \mu$) can either mean that the grains have an aspect ratio of 1 or are randomly organised. This type of response is commonly associated with sand. In principle, the ratio of $\lambda$ to $\mu$ should help discriminate between sand and shale lithologies Figure 3.15 a). In terms of fluid discrimination, the change
in fluid only has a negligible effect on the rigidity of the rock, but may have a strong effect on the incompressibility (Perez and Tonn, 2003). Gas saturated data points are therefore expected to have lower $\lambda_\rho$ values and similar $\mu_\rho$ values, compared to brine saturated data points of the same lithology Figure 3.15 b).
3.6. AVO MODELLING

AVO (amplitude variation with offset) modelling is a commonly used technique in prestack seismic analysis. It significantly contributes in seismic data acquisition design, and prestack seismic data processing and interpretation. The technique may also be used for verifying and developing AVO theories. By nature, it is an exercise of multidisciplinary integration, which helps enhance reservoir characterisation and reduce hydrocarbon exploration risks (Li et al., 2007). The major theories associated with AVO modelling are discussed in this section.

3.6.1. Angle dependent reflection coefficient

When a seismic wave, travelling in a medium, encounters another medium with a different impedance $I$ (the product of the density $\rho$ and velocity $V$ of the medium, i.e. $I = \rho \times V$), the wave is split into reflected and refracted P-wave components and reflected and refracted S-wave components (Figure 3.16). The reflection and refraction coefficients are a function of the media’s elastic properties (density, bulk and shear moduli) and the angle of incidence (Chopra and Castagna, 2014).

![Figure 3.16: Schematic illustration of raypaths for a plane wave (I), incident on an interface between two media. At the interface, the incident energy splits into 4 components. No shear waves are generated at normal incidence. With increasing angle of incidence ($\theta_1$), the the P-wave energy is reflected (at angle $\theta_1$) and transmitted (at angle $\theta_2$). In addition, part of the P-wave energy is converted into S-wave energy, giving rise to the reflected shear component (at angle $\phi_1$) and the transmitted component (at angle $\phi_2$). Particle movement caused by the seismic waves is shown by the double arrows for each individual wave (from Chopra and Castagna, 2014).](image_url)

At an interface between two isotropic, homogeneous layers at normal incidence, the ratio of the reflected wave amplitude to the incident wave amplitude (known as
normal incidence reflectivity) is given by the equation (Mavko et al., 2009):

\[
R_{PP} = \frac{\rho_2 V_{P2} - \rho_1 V_{P1}}{\rho_2 V_{P2} + \rho_1 V_{P1}} \tag{3.6.1.1}
\]

\[
R_{SS} = \frac{\rho_2 V_{S2} - \rho_1 V_{S1}}{\rho_2 V_{S2} + \rho_1 V_{S1}} \tag{3.6.1.2}
\]

where \( R_{PP} \) is the normal incidence P-to-P reflectivity, \( R_{SS} \) is the normal incidence S-to-S reflectivity, and the subscripts 1 and 2 refer to the first and second media, respectively.

More often, however, an incident P-wave strikes the boundary between two media at an oblique angle. The reflection and transmission coefficients vary as a function of the angle of incidence and as a function of the three independent elastic parameters on each side of the reflecting interface and are described by the complicated Zoeppritz equations (Chopra and Castagna, 2014; Avseth et al., 2005):

\[
\begin{bmatrix}
\cos \theta_i & \frac{V_{P1}}{V_{P1}^2} \sin \phi_r & -\frac{V_{P1}}{V_{S1}} \sin \phi_r \\
-\sin \theta_i & \frac{V_{P1}}{V_{P1}^2} \cos \phi_r & -\frac{V_{P1}}{V_{S1}^2} \cos \phi_r \\
-\cos 2\phi_r & -\sin 2\phi_r & \frac{\rho_2 V_{S2}^2 - \rho_1 V_{S1}^2}{\rho_1 V_{S1}^2 - \rho_2 V_{S2}^2} \sin 2\phi_t \\
\sin 2\theta_i & \frac{V_{P1}^2}{V_{S1}^2} \cos 2\phi_r & \frac{\rho_2 V_{S2}^2 - \rho_1 V_{S1}^2}{\rho_1 V_{S1}^2 - \rho_2 V_{S2}^2} \cos 2\phi_t \\
\end{bmatrix}
\times
\begin{bmatrix}
R_{PP} \\
R_{PS} \\
T_{PP} \\
T_{PS} \\
\end{bmatrix}
= \begin{bmatrix}
\cos \theta_i \\
\sin \theta_i \\
\cos 2\phi_r \\
\sin 2\phi_t \\
\end{bmatrix} \tag{3.6.1.3}
\]

where \( V_P \) – P-wave velocity, \( V_S \) – S-wave velocity, \( \rho \) – density. Subscripts 1 and 2 represent Medium 1 and Medium 2, respectively. \( \theta_i \) – angle of incidence, i.e. the angle that the P-reflected ray \( R_{PP} \) makes with the normal. \( \theta_t \) – angle of transmission, i.e. the angle that the P-transmitted ray \( T_{PP} \) makes with the normal. Similarly, \( \phi_r \) and \( \phi_t \) are the angle of reflection and the angle of transmission for the S-reflected ray \( R_{PS} \) and the S-transmitted ray \( T_{PS} \), respectively.

These equations are complex and require a laborious solution. Therefore it is challenging to obtain an intuitive understanding of the various parameters influencing the reflection-coefficient curve. Several approximations have been developed that readily reveal the informational content depicted by amplitude behaviour. Each of these approximations have some associated assumptions and limitations.

The approximation by Aki and Richards (1980) with the simplification by Wiggins et al. (1983, 1985) has been used in this study. Aki and Richards (1980) have derived the equation for the reflection P-wave in a form comprising three terms: (i) the first involving density; (ii) the second involving P-wave velocity; and (iii) the third involving
S-wave velocity. Their equation reads as follows:

\[
R(\theta) = \frac{1}{2} \left( 1 - 4 \frac{V_S^2}{V_P^2} \sin^2 \theta \right) \frac{\Delta \rho}{\rho} + \frac{1}{2} \cos^2 \theta \frac{\Delta V_P}{V_P} - \left( 4 \frac{V_S^2}{V_P^2} \sin^2 \theta \right) \frac{\Delta V_S}{V_S},
\]

(3.6.1.4)

where,

\[
\Delta V_P = V_{P2} - V_{P1}, \quad \Delta V_S = V_{S2} - V_{S1},
\]

\[
V_S = \frac{V_{S1} + V_{S2}}{2}, \quad V_P = \frac{V_{P1} + V_{P2}}{2},
\]

\[
\Delta \rho = \rho_2 - \rho_1, \quad \theta = \frac{\theta_1 + \theta_2}{2}, \quad \text{and} \quad \rho = \frac{\rho_1 + \rho_2}{2}.
\]

These are good approximations if the relative changes of elastic parameters on both sides of the interface are sufficiently small (Chopra and Castagna, 2014). A comparison between the approximations by Aki and Richards (1980) and the Zoeppritz equations is shown in Figure 3.17.

Figure 3.17: Comparison of the exact solution of the Zoeppritz equations (red line) with the Aki and Richards approximation (orange line). The approximation deviates slightly from the exact solution after 35° (redrawn from Chopra and Castagna, 2014).

Wiggins et al. (1983, 1985) have suggested a further simplification by assuming \( V_S/V_P = 0.5 \), and ignoring the third term (which is applicable for a restricted angle
range) (Chopra and Castagna, 2014). Equation 3.6.1.4 can then be rewritten as follows:

\[
R(\theta) = \frac{1}{2} \left( \Delta V_P + \Delta \rho \right) + \left( \frac{1}{2} \frac{\Delta V_P}{V_P} - \frac{\Delta \rho}{\rho} - \frac{1}{2} \frac{\Delta V_S}{V_S} \right) \sin^2 \theta
\]

\[
= R_P + (R_P - 2R_S) \sin^2 \theta
\]

\[
= R_P + G \sin^2 \theta
\]

(3.6.1.5)

where,

\[
G = R_P - 2R_S, \quad R_P = \frac{1}{2} \left( \Delta V_P + \Delta \rho \right), \quad \text{and}
\]

\[
R_S = \frac{1}{2} \left( \frac{\Delta V_S}{V_S} + \frac{\Delta \rho}{\rho} \right)
\]

Variables \( R_P \) and \( G \) correspond to the AVO intercept \( A \) and the gradient \( B \), respectively.

### 3.6.2. Generation of synthetic seismogram

A synthetic seismogram is defined as an artificial seismic reflection record, which has been produced by assuming that a particular waveform travels through an assumed model (Yilmaz, 2008). In this study, a 1D synthetic seismogram has been generated for the purpose of forward AVO modelling. It is produced by simply convolving a chosen wavelet with a reflectivity function, which is computed from the sonic velocities and the density data (Figure 3.18). The sonic and density data are averaged beforehand to larger sample intervals in order to upscale the well logs to seismic frequencies. Averaging or ‘blocking’ well logs helps the interpreter in capturing significant changes and associating major lithologic changes with specific peaks or troughs.

In practice, the propagating seismic energy pulse lengthens due to loss of its higher frequency components by absorption, as the earth acts as a low-pass filter. The wavelet therefore acts as a time-varying seismic pulse. Further complications include the superposition of various types of noise, such as multiples, direct and refracted body waves, surface waves, air waves and coherent and incoherent noise unconnected with the seismic source (Kearey et al., 2013). All of these effects contribute to the complex appearance of real seismic data. Some of these effects can be included when generating synthetic seismograms. This has not been done in this study for the purpose of simplicity and inherent uncertainties when creating complex models. A constant wavelet was also assumed.

### 3.6.2.1. Wavelet selection

The selection of a wavelet for the purpose of synthetic seismogram creation is an important step which should not be overlooked. The wavelet of choice should have a frequency response and band width similar to that of the relevant seismic data. When available, it is a common practice to extract a statistical wavelet from actual seismic data. In other cases, it is common to use an idealised wavelet for the purpose of creating synthetic seismics, and a number of such wavelets exist (Simm et al., 2014).

One of the most simple of these is called the Ricker wavelet (Figure 3.19) (Ricker,
CHAPTER 3. METHODOLOGY AND THEORETICAL BACKGROUND

Figure 3.18: Creation of a reflection seismogram. The reflection seismogram is shown as the convolved output of a reflectivity function with an input pulse (from Kearey et al., 2013). * – convolution.

1940). It is defined by a single central frequency and only has two side lobes. However, being very simplistic, the Ricker wavelet is often advised against, mainly due to its peaked amplitude spectrum, which is in contrast to a generally flat-topped response of real seismic (Hosken, 1988). It can, however, be very useful as a first approximation.

![Ricker wavelet and amplitude spectrum](image)

Figure 3.19: Example of a Ricker wavelet in the time domain (left) and the frequency domain (right) (modified from Simm et al., 2014).

With increasing depth, the dominant frequency of the seismic waves tends to decrease due to absorption, and the velocity tends to increase due to compaction. Therefore, the vertical resolution decreases as a function of depth (Kearey et al., 2013). This should be taken into consideration when generating a idealised wavelet as it may, on the one hand, give a resolution which is too high to be achieved by an actual seismic survey, or, on the other hand, be too low and not capture the interval of interest.
3.6.3. AVO classification of reservoir sands

A classification scheme for gas sands based on the normal incidence P-wave reflection coefficient was originally proposed by Rutherford and Williams (1989). The authors defined three sand classes according to their AVO characteristics. Castagna and Swan (1997) extended this classification scheme to include Class 4 sands. The concept was later expanded by Castagna et al. (1998) based on where the top of the gas sands is located in the Intercept $R(0)$ versus Gradient $G$ crossplot. The Amplitude versus offset behaviour of the different sand classes is summarised in Figure 3.20.

![AVO classes diagram](image)

**Figure 3.20**: AVO classes. Roman numerals I-IV correspond to the numbers 1-4, as used in the text (from Simm et al., 2014).

3.6.3.1. Class 1 anomalies

A Class 1 sand has a higher acoustic impedance than the encasing medium, usually shale. The zero-offset reflection coefficient is positive (positive intercept) and decreases in amplitude magnitude (has a negative gradient) with increasing offset faster than the background trend. When an adequate offset range is available, the magnitude of the reflectivity can change polarity. Due to this change in polarity, the reflection response can cancel out in CMP stacked data, producing an enhanced dim-spot effect. Typically, this type of gas sand is associated with onshore area, well consolidated sands with a low $V_P/V_S$ ratio. (Rutherford and Williams, 1989; Chopra and Castagna, 2014; Castagna et al., 1998).

3.6.3.2. Class 2 anomalies

A Class 2 sand has a low acoustic impedance contrast and a negative gradient. On stacked seismic data, such sands can appear as bright spots, dim spots, or polarity reversals and are commonly undetectable in noisy data (Chopra and Castagna, 2014). Ross and Kinman (1995) subdivided the Class 2 anomalies into those having a positive intercept and a negative gradient, causing a phase reversal with offset (Class 2p) and those with a negative intercept and a negative gradient - no phase reversal (Class 2).
Such anomalies are commonly associated with moderately compacted and consolidated sediments. The AVO response will behave as a Class 2 offset response in cases where the density of sand is lower than that of the encasing shale and the velocity in the sand is greater than in the shale, regardless if the sand’s pore fluids are gas charged (Ross and Kinman, 1995; Chopra and Castagna, 2014).

3.6.3.3. Class 3 anomalies

A Class 3 sand has a lower acoustic impedance than the encasing medium. The zero-offset reflection coefficient is negative (negative intercept) and increases in amplitude magnitude (has a negative gradient) with increasing offset, displaying a high reflectivity at all offsets. Therefore it is associated with the ‘bright spot’ anomalies seen on stacked seismic data. These are typically unconsolidated sands found in marine environments (Rutherford and Williams, 1989; Chopra and Castagna, 2014).

3.6.3.4. Class 4 anomalies

A Class 4 sand has a lower impedance than the encasing medium. The zero-offset reflection coefficient is negative (negative intercept) and decreases in amplitude magnitude (has a positive gradient) with increasing offset. Class 4 anomalies are associated with shallow, unconsolidated sands or soft sands below a hard cap rock, such as a hard shale, siltstone or carbonate (Castagna and Swan, 1997; Chopra and Castagna, 2014).

3.6.4. AVO gradient versus Intercept

AVO interpretation can be aided with the use the AVO Gradient (B) versus Intercept (A) plot (Figure 3.21). Brine saturated sandstones and shales tend to follow a well defined ‘background trend’ in the Gradient versus Intercept domain, under a variety of petrophysical assumptions. In most cases, Gradient and Intercept have a negative correlation for ‘background’ rocks, but may also have a positive correlation where high $V_P/V_S$ ratios exist, such as in very soft shallow sediments. Therefore, it is possible for fully brine saturated shallow events with large reflection coefficients to exhibit large increases in AVO.

Deviations from the background trend may be related to hydrocarbons or lithologies with anomalous elastic properties. Gas sands can be classified according to where they plot in the AVO Gradient versus Intercept domain. Bright-spot producing gas sands fall in quadrant III (negative Intercept and Gradient), and exhibit amplitude increases with offset. High impedance gas sands plot in quadrant IV (positive Intercept and Gradient). These sands initially show decreasing AVO and may reverse polarity. Certain bright-spot producing sands plot in quadrant II and show decreasing AVO. This may happen where the gas sand S-wave is lower than that of the overlying formation.
3.6.5. Gassmann’s fluid substitution

The fluid substitution problem is one of the most important in rock physics analysis. It concerns using seismic velocities in rocks saturated with one type of fluid to predict those of rocks saturated with another type of fluid, or using seismic velocities in a dry rock to predict those in a saturated rock (Mavko et al., 2009). Known as fluid substitution, this is an important part of the seismic attribute study as the interpreter is able to model various fluid scenarios which may explain an observed amplitude variation with offset (AVO) anomaly (Smith et al., 2003).

When a seismic wave passes through a porous, saturated rock, the pore fluid contributes to the rock’s resistance to compression, stiffening the rock. In Gassmann’s equations the bulk moduli of the porous rock frame, \( \kappa_d \), the pore fluid, \( \kappa_f \), and the nonporous solid material comprising the rock, \( \kappa_s \), are mechanically related to the bulk modulus of the saturated rock, \( \kappa^* \) (Chopra and Castagna, 2014):

\[
\kappa^* = \kappa_d + \frac{(1 - \frac{\kappa_d}{\kappa_s})^2}{\phi + \frac{1-\phi}{\kappa_s} - \frac{\kappa_d}{\kappa_s}^2}, \quad \mu^* = \mu_d
\]  

(3.6.5.1)

where \( \phi \) – porosity; \( \mu^* \) – effective shear modulus of fluid saturated rock; \( \mu_d \) – effective shear modulus of dry rock.

Gassmann’s relations operate under the following simplifying assumptions and limitations (Smith et al., 2003; Chopra and Castagna, 2014):

- **Homogeneous and isotropic rock.** This assumption is not correct for rocks composed of multiple mineral types with large contrasts in elastic stiffness or rocks composed of anisotropic minerals which are preferentially oriented. Gassmann’s
relations can be modified to include anisotropy, but this is not common in practice. Average solid grain properties can be estimated using Hill (1963) or other equations. However, the presence of clay complicates the physics significantly and a simple Hill (1963) average will not suffice in such case.

- **Rock is saturated with a single fluid.** For mixtures of different fluids, the Wood (1941) equation is commonly used. It assumes that the stress in each fluid component is the same, meaning that the strains within the different fluid phases vary greatly. There is debate about how accurate the assumptions by Wood’s equation are and the question is part of ongoing research.

- **All of the pores are connected and the fluids are moveable.** All isolated porosity should be included into the solid-grain modulus. Although Gassmann’s relations are free of assumptions about pore geometry, more complex models are often needed when multiple pore types are present in the rock. Assumptions about pore connectivity and pore type are probably violated in low-porosity rocks.

- **Low frequencies.** Frequencies must be low enough so that pore pressures equalize over a length scale much greater than the pore dimension and much less than the wavelength of the passing seismic wave. Gassmann’s relations are thus more applicable at low seismic frequencies. Formulations by Biot (1956, 1962) should be used for high frequencies. Gassmann’s relations may not be applicable at sonic logging frequencies, especially when applied to low-porosity or shaley sands, or to carbonates. This is due to violations regarding frequency or pore connectivity assumptions.

- **Physically and chemically inert rock frame.** Gassmann’s relations do not take into consideration pore-pressure changes associated with changes in fluid saturation. This effect is common in practice and may result in the rock frame becoming stiffer if pore pressures drop and vice versa.

- **Closed rock system.** This assumes that there is no fluid flow in or out of the rock.

- **No cavitation** Pore fluid remains coupled to the solid material.
CHAPTER 4

Petrophysical analysis

Results and discussion of the petrophysical interpretation are presented in this chapter, followed by an uncertainty analysis. Each formation (Kobbe, Snadd and Stø) is discussed separately. The interpretation was carried out in 3 main steps: (i) shale volume was estimated using the gamma ray, and the combination of the neutron and density logs; (ii) both total and effective (including a shale term) porosities, and water saturation were estimated from the combination of neutron, density, sonic and resistivity logs; (iii) net-to-gross fractions for net sand (cutoff: $V_{sh} = 0.4$), net reservoir (cutoff: $V_{sh} = 0.4$, $\phi_t = 0.07$) were computed for each formation, distinguishing reservoir intervals. Net-pay-to-gross fraction (cutoff: $V_{sh} = 0.4$, $\phi_t = 0.07$, $S_w = 0.55$) was also computed in the hydrocarbon saturated reservoirs. For a detailed discussion of the methods used during the petrophysical analysis, please see Section 3.4 of the ‘Methodology and theoretical background’ chapter.

4.1. Results

4.1.1. Kobbe Formation

The Kobbe Formation is present in all wells except 7324/8-1 (Wisting), where it has not been penetrated. Two other wells (7324/7-1S and 7228/1-1) have encountered the Kobbe Formation, but have not reached its base. Considering the other wells, the Formation is thickest in well 7228/2-1S (Hammerfest Basin), i.e. 1136 m. In the remaining wells, the Formation has a thickness varying from 624 m to 665 m.

Considering the entire formation, the average total porosity (estimated from the neutron and density log combination) varies between 8%–13%, while the average effective porosity (estimated from the neutron-density log combination, including a shale term) has a range of 5%–10%. The average shale volume (estimated from the gamma ray and neutron-density log combination) varies between 53–61%. Net-sand-to-gross ranges from 14–25%, while the net-reservoir-to-gross ranges between 12–24%. Results of the petrophysical evaluations for the entire formation in each well are presented in Table 4.1. The formation is found to have high shale volumes with few reservoir quality intervals. Due to the high shale volume, the estimated total and effective porosities are found to diverge by up to 7%.
Gas bearing intervals are present in wells 7225/3-1 (Norvarg discovery), 7225/3-2 (Norvarg appraisal) and 7226/2-1 (Ververis discovery); minor gas has been reported in well 7324/10-1; weak hydrocarbon shows are described in well 7324/7-1S; and the formation is fully brine saturated in well 7228/1-1 (NPD, 2016).

**Table 4.1:** Results of the petrophysical analysis of the Kobbe Formation. Gross – total thickness in meters; $V_{sh}$ – average shale volume; $\phi_t$ – average total porosity; $\phi_e$ – average effective porosity; Net(s)/G – net sand to gross; Net(r)/G – net reservoir to gross. Wells are arranged in the table from west (top) to east (bottom).

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Gross</th>
<th>$V_{sh}$</th>
<th>$\phi_t$</th>
<th>$\phi_e$</th>
<th>Net(s)/G</th>
<th>Net(r)/G</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Kobbe</td>
<td>414+</td>
<td>0.60</td>
<td>0.13</td>
<td>0.06</td>
<td>0.14</td>
<td>0.12</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Kobbe</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Kobbe</td>
<td>665</td>
<td>0.58</td>
<td>0.11</td>
<td>0.08</td>
<td>0.14</td>
<td>0.13</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Kobbe</td>
<td>633</td>
<td>0.58</td>
<td>0.09</td>
<td>0.06</td>
<td>0.14</td>
<td>0.12</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Kobbe</td>
<td>624</td>
<td>0.61</td>
<td>0.08</td>
<td>0.05</td>
<td>0.14</td>
<td>0.13</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Kobbe</td>
<td>631</td>
<td>0.56</td>
<td>0.11</td>
<td>0.07</td>
<td>0.22</td>
<td>0.21</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Kobbe</td>
<td>201+</td>
<td>0.53</td>
<td>0.13</td>
<td>0.10</td>
<td>0.25</td>
<td>0.24</td>
</tr>
</tbody>
</table>

Reservoir intervals in the Kobbe Formation were found to be relatively thin (up to approx. 18 m), with poor reservoir properties. The best reservoir intervals in the Kobbe Formation are found in well 7225/3-2 (Norvarg appraisal). Here, 3 gas saturated intervals were encountered. Composite well log plots, showing the three reservoirs and surrounding shales, are shown in Figure 4.1, Figure 4.2 and Figure 4.3. For composite log plots for the Kobbe Formation, please see Appendix B.

**Figure 4.1:** Composite log plot over the gas saturated reservoir ‘Channel A’ and surrounding shales in the Kobbe Formation in well 7225/3-2 (Norvarg appraisal well).
CHAPTER 4. PETROPHYSICAL ANALYSIS

Figure 4.2: Composite log plot over the gas saturated reservoir ‘Channel D’ and surrounding shales in the Kobbe Formation in well 7225/3-2 (Norvarg appraisal well).

Figure 4.3: Composite log plot over the gas saturated reservoir ‘Anomaly 2’ and surrounding shales in the Kobbe Formation in well 7225/3-2 (Norvarg appraisal well).
The intervals are described by NPD (2016) as ‘Channel A’ (1590-1608.7 m MDKB), ‘Channel D’ (1775-1808.1 m MDKB) and ‘Anomaly 2’ (1909.6-1927.9 m MDKB). Based on our petrophysical evaluation results we modified the depths of these intervals as: ‘Channel A’ (1593-1608 m MDKB), ‘Channel D’ (1777-1793 m MDKB) and ‘Anomaly 2’ (1910-1928 m MDKB).

Results of the net-to-gross evaluations are presented in Table 4.2. The reservoir intervals in the Kobbe Formation are thin (up to 18 m) and have poor reservoir properties. High shale volume contributes to low estimated effective porosities in reservoir intervals. On the other hand, most of the reservoir intervals are estimated to have some amount of hydrocarbon saturation.

Table 4.2: Reservoir intervals in the Kobbe Formation. $V_{sh}$ – average shale volume, $\phi_e$ – average effective porosity, $S_w$ – average water saturation, as estimated by petrophysical analysis. $N(r)/G$ – net reservoir to gross, $N(p)/G$ – net pay to gross.
4.1.2. Snadd Formation

The Snadd Formation is present in all the wells. The base of the formation has not been penetrated in well 7324/8-1 (Wisting). The Formation is thickest in the westernmost wells 7228/2-1S (Bjarmeland Basin, north of Maud Basin), i.e. 1167 m; 7324/10-1 (Bjarmeland Platform, east of Maud Basin), i.e. 1001 m; and the easternmost well 7228/2-1S (Hammerfest Basin), i.e. 915 m. It is thinnest in the central part of the study area, in wells 7225/3-1 (Norvarg) and 7225/3-2 (Norvarg), i.e. 342 m and 361 m, respectively (Norvarg Dome, Bjarmeland Platform).

Considering the entire formation, the average total porosity (estimated from the neutron-density logs) varies between 13%–15%, while the average effective porosity (estimated from the neutron-density logs, including a shale term) has a range of 8%–13%. The average shale volume (evaluated from the combination of gamma ray, neutron and density logs) varies between 42–51%. The net-sand-to-gross ranges from 26% to 45%, while the net reservoir to gross ranges from 21% to 44%.

Despite having intervals with good reservoir properties and significant source intervals with both oil- and gas-prone kerogen (NPD, 2016), no significant hydrocarbon accumulations exist in the studied wells. In 5 of the 8 wells hydrocarbon shows have been found in samples during drilling (NPD, 2016). Results of the petrophysical evaluation for the entire formation are presented in Table 4.3.

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Gross</th>
<th>V_{sh}</th>
<th>\phi_t</th>
<th>\phi_e</th>
<th>Net(s)/G</th>
<th>Net(r)/G</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Snadd</td>
<td>1167</td>
<td>0.51</td>
<td>0.13</td>
<td>0.08</td>
<td>0.26</td>
<td>0.24</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Snadd</td>
<td>158+</td>
<td>0.47</td>
<td>0.15</td>
<td>0.12</td>
<td>0.35</td>
<td>0.34</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Snadd</td>
<td>1001</td>
<td>0.49</td>
<td>0.15</td>
<td>0.13</td>
<td>0.30</td>
<td>0.30</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Snadd</td>
<td>342</td>
<td>0.42</td>
<td>0.15</td>
<td>0.11</td>
<td>0.43</td>
<td>0.39</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Snadd</td>
<td>361</td>
<td>0.45</td>
<td>0.15</td>
<td>0.12</td>
<td>0.22</td>
<td>0.21</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Snadd</td>
<td>642</td>
<td>0.44</td>
<td>0.15</td>
<td>0.11</td>
<td>0.45</td>
<td>0.44</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Snadd</td>
<td>376</td>
<td>0.44</td>
<td>0.14</td>
<td>0.10</td>
<td>0.40</td>
<td>0.36</td>
</tr>
</tbody>
</table>

In contrast to the Kobbe Formation, the Snadd Formation exhibits more numerous reservoir quality intervals with mostly better reservoir qualities (Table 4.4). The most striking features of the formation are the recurring relatively thick (up to 58 m) good reservoir quality sand intervals (see Figure 4.4 and Figure 4.5). As with the Kobbe Formation, relatively large shale volumes contribute to lower effective porosities than total porosities (up to around 5%). For composite log plots for the Snadd Formation, please see Appendix B.
**Figure 4.4:** Composite log plot over selected brine saturated reservoir intervals and surrounding shales in the Snadd Formation in well 7226/2-1 (Vereris).

**Figure 4.5:** Composite log plot over selected brine saturated reservoir intervals and surrounding shales in the Snadd Formation in well 7228/1-1.
Table 4.4: Reservoir intervals in the Snadd Formation. $V_{sh}$ – average shale volume, $\phi_e$ – average effective porosity, $S_w$ – average water saturation, as estimated by petrophysical analysis. N(r)/G – net reservoir to gross, N(p)/G – net pay to gross.

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Interval</th>
<th>Gross</th>
<th>$V_{sh}$</th>
<th>$\phi_e$</th>
<th>$S_w$</th>
<th>N(r)/G</th>
<th>N(p)/G</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Snadd</td>
<td>896-905</td>
<td>9</td>
<td>0.20</td>
<td>0.15</td>
<td>1.00</td>
<td>0.88</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>918-957</td>
<td>39</td>
<td>0.27</td>
<td>0.15</td>
<td>0.99</td>
<td>0.93</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>971-975</td>
<td>4</td>
<td>0.34</td>
<td>0.11</td>
<td>1.00</td>
<td>0.80</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1031-1037</td>
<td>6</td>
<td>0.29</td>
<td>0.14</td>
<td>0.94</td>
<td>0.94</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1064-1068</td>
<td>4</td>
<td>0.26</td>
<td>0.17</td>
<td>0.77</td>
<td>0.87</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1161-1174</td>
<td>13</td>
<td>0.20</td>
<td>0.15</td>
<td>0.94</td>
<td>0.99</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1181-1204</td>
<td>23</td>
<td>0.19</td>
<td>0.14</td>
<td>0.95</td>
<td>0.95</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1610-1615</td>
<td>5</td>
<td>0.12</td>
<td>0.13</td>
<td>0.78</td>
<td>0.84</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1634-1663</td>
<td>29</td>
<td>0.13</td>
<td>0.12</td>
<td>0.51</td>
<td>0.94</td>
<td>0.71</td>
</tr>
<tr>
<td>7234/8-1</td>
<td>Snadd</td>
<td>773-779</td>
<td>6</td>
<td>0.33</td>
<td>0.21</td>
<td>0.98</td>
<td>0.94</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>782-790</td>
<td>8</td>
<td>0.20</td>
<td>0.17</td>
<td>0.88</td>
<td>0.86</td>
<td>–</td>
</tr>
<tr>
<td>7234/10-1</td>
<td>Snadd</td>
<td>807-818</td>
<td>11</td>
<td>0.32</td>
<td>0.16</td>
<td>0.95</td>
<td>0.75</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>822-834</td>
<td>12</td>
<td>0.10</td>
<td>0.24</td>
<td>0.99</td>
<td>1.00</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>892-899</td>
<td>7</td>
<td>0.39</td>
<td>0.15</td>
<td>0.98</td>
<td>0.65</td>
<td>–</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Snadd</td>
<td>636-673</td>
<td>37</td>
<td>0.25</td>
<td>0.23</td>
<td>0.98</td>
<td>0.91</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>928-946</td>
<td>18</td>
<td>0.30</td>
<td>0.19</td>
<td>0.93</td>
<td>0.98</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1096-1103</td>
<td>7</td>
<td>0.23</td>
<td>0.19</td>
<td>0.89</td>
<td>0.91</td>
<td>–</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Snadd</td>
<td>804-841</td>
<td>37</td>
<td>0.18</td>
<td>0.18</td>
<td>0.86</td>
<td>0.97</td>
<td>–</td>
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<td></td>
<td>Snadd</td>
<td>844-852</td>
<td>8</td>
<td>0.35</td>
<td>0.16</td>
<td>0.89</td>
<td>0.77</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>884-889</td>
<td>5</td>
<td>0.20</td>
<td>0.23</td>
<td>0.65</td>
<td>1.00</td>
<td>0.27</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>891-895</td>
<td>4</td>
<td>0.27</td>
<td>0.20</td>
<td>0.86</td>
<td>0.84</td>
<td>–</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Snadd</td>
<td>916-923</td>
<td>7</td>
<td>0.33</td>
<td>0.17</td>
<td>0.86</td>
<td>0.69</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>924-931</td>
<td>7</td>
<td>0.14</td>
<td>0.17</td>
<td>0.81</td>
<td>0.99</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1018-1021</td>
<td>3</td>
<td>0.12</td>
<td>0.21</td>
<td>0.56</td>
<td>0.98</td>
<td>0.72</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1087-1095</td>
<td>8</td>
<td>0.21</td>
<td>0.16</td>
<td>0.85</td>
<td>0.96</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1117-1125</td>
<td>8</td>
<td>0.12</td>
<td>0.19</td>
<td>0.82</td>
<td>0.90</td>
<td>–</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Snadd</td>
<td>814-842</td>
<td>28</td>
<td>0.27</td>
<td>0.17</td>
<td>1.00</td>
<td>0.75</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>915-919</td>
<td>4</td>
<td>0.25</td>
<td>0.22</td>
<td>1.00</td>
<td>0.91</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>927-938</td>
<td>11</td>
<td>0.25</td>
<td>0.23</td>
<td>0.99</td>
<td>0.82</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1094-1099</td>
<td>5</td>
<td>0.22</td>
<td>0.17</td>
<td>0.95</td>
<td>0.93</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1122-1130</td>
<td>8</td>
<td>0.15</td>
<td>0.19</td>
<td>0.96</td>
<td>0.96</td>
<td>–</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Snadd</td>
<td>1066-1087</td>
<td>21</td>
<td>0.36</td>
<td>0.12</td>
<td>1.00</td>
<td>0.65</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1126-1138</td>
<td>12</td>
<td>0.33</td>
<td>0.16</td>
<td>0.98</td>
<td>0.96</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1247-1299</td>
<td>52</td>
<td>0.34</td>
<td>0.16</td>
<td>0.99</td>
<td>0.94</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1311-1319</td>
<td>8</td>
<td>0.31</td>
<td>0.15</td>
<td>1.00</td>
<td>0.94</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1361-1419</td>
<td>58</td>
<td>0.27</td>
<td>0.22</td>
<td>0.99</td>
<td>0.98</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1456-1464</td>
<td>8</td>
<td>0.33</td>
<td>0.16</td>
<td>1.00</td>
<td>0.88</td>
<td>–</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Snadd</td>
<td>1150-1166</td>
<td>16</td>
<td>0.24</td>
<td>0.14</td>
<td>0.99</td>
<td>0.90</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1170-1191</td>
<td>21</td>
<td>0.22</td>
<td>0.17</td>
<td>0.99</td>
<td>0.86</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1267-1275</td>
<td>8</td>
<td>0.28</td>
<td>0.16</td>
<td>0.97</td>
<td>0.84</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1326-1368</td>
<td>42</td>
<td>0.20</td>
<td>0.19</td>
<td>0.97</td>
<td>0.88</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1371-1375</td>
<td>4</td>
<td>0.18</td>
<td>0.21</td>
<td>0.97</td>
<td>1.00</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Snadd</td>
<td>1413-1422</td>
<td>9</td>
<td>0.23</td>
<td>0.15</td>
<td>0.84</td>
<td>0.88</td>
<td>–</td>
</tr>
</tbody>
</table>
4.1.3. Stø Formation

The Stø formation is penetrated by 6 of the 8 studied wells: 7324/7-1S, 7324/8-1 (Wisting), 7324/10-1, 7225/3-1 (Norvarg), 7225/3-2 (Norvarg) and 7228/2-1S. It is thickest in the central part of the study area, in wells 7225/3-1 (Norvarg) and 7225/3-2, i.e. 43 m and 61 m, respectively. The formation is not present in wells 7226/2-1 (Ververis) and 7228/1-1. Petrophysical analysis results for the entire formation are shown in Table 4.5, while the results of net-to-gross evaluations are given in Table 4.6.

Considering the entire formation, the average total porosity varies from 14%–27%, while average effective porosity has a range of 12%–26%. Average shale volume ranged between 6%–36%. Net sand to gross varied from 46% to 100%, while the net reservoir to gross had a range of 44% to 100%. Formation is oil saturated in well 7324/8-1 (Wisting) (Figure 4.6), gas saturated in well 7225/3-1 (Norvarg) (Figure 4.7), has hydrocarbon shows in well 7228/2-1S and is water bearing in the other wells (NPD, 2016).

Table 4.5: Results of the petrophysical analysis of the Stø Formation. Gross – total thickness in meters; $V_{sh}$ – average shale volume; $\phi_t$ – average total porosity; $\phi_e$ – average effective porosity; Net(s)/G – net sand to gross; Net(r)/G – net reservoir to gross.

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Gross</th>
<th>$V_{sh}$</th>
<th>$\phi_t$</th>
<th>$\phi_e$</th>
<th>Net(s)/G</th>
<th>Net(r)/G</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Stø</td>
<td>16</td>
<td>0.06</td>
<td>0.23</td>
<td>0.23</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Stø</td>
<td>17</td>
<td>0.07</td>
<td>0.20</td>
<td>0.20</td>
<td>0.96</td>
<td>0.95</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Stø</td>
<td>8</td>
<td>0.19</td>
<td>0.27</td>
<td>0.26</td>
<td>0.91</td>
<td>0.91</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Stø</td>
<td>43</td>
<td>0.25</td>
<td>0.21</td>
<td>0.19</td>
<td>0.70</td>
<td>0.66</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Stø</td>
<td>61</td>
<td>0.24</td>
<td>0.19</td>
<td>0.17</td>
<td>0.46</td>
<td>0.44</td>
</tr>
<tr>
<td>7226/2-1</td>
<td>Stø</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7228/1-1</td>
<td>Stø</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Stø</td>
<td>25</td>
<td>0.36</td>
<td>0.14</td>
<td>0.12</td>
<td>0.54</td>
<td>0.54</td>
</tr>
</tbody>
</table>

The Stø formation has good reservoir properties in all wells, except 7228/2-1S (Hammerfest Basin), with low shale volume and high porosities. However, the average thickness is not much (~28 m) in comparison to the Triassic Kobbe and Snadd Formations (for composite log plots for the Stø Formation, please see Appendix B).

Table 4.6: Reservoir intervals in the Stø Formation. $V_{sh}$ – average shale volume, $\phi_e$ – average effective porosity, $S_w$ – average water saturation, as estimated by petrophysical analysis. N(r)/G – net reservoir to gross, N(p)/G – net pay to gross.

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Interval</th>
<th>Gross</th>
<th>$V_{sh}$</th>
<th>$\phi_e$</th>
<th>$S_w$</th>
<th>N(r)/G</th>
<th>N(p)/G</th>
</tr>
</thead>
<tbody>
<tr>
<td>7324/7-1S</td>
<td>Stø</td>
<td>780-796</td>
<td>16</td>
<td>0.06</td>
<td>0.23</td>
<td>0.96</td>
<td>1.00</td>
<td>–</td>
</tr>
<tr>
<td>7324/8-1</td>
<td>Stø</td>
<td>662-679</td>
<td>17</td>
<td>0.06</td>
<td>0.20</td>
<td>0.03</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>7324/10-1</td>
<td>Stø</td>
<td>569-577</td>
<td>8</td>
<td>0.19</td>
<td>0.26</td>
<td>1.00</td>
<td>0.90</td>
<td>–</td>
</tr>
<tr>
<td>7225/3-1</td>
<td>Stø</td>
<td>727-751</td>
<td>24</td>
<td>0.08</td>
<td>0.20</td>
<td>0.24</td>
<td>0.93</td>
<td>1.00</td>
</tr>
<tr>
<td>7225/3-2</td>
<td>Stø</td>
<td>766-770</td>
<td>4</td>
<td>0.26</td>
<td>0.21</td>
<td>0.96</td>
<td>1.00</td>
<td>–</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Stø</td>
<td>729-755</td>
<td>26</td>
<td>0.13</td>
<td>0.21</td>
<td>1.00</td>
<td>0.90</td>
<td>–</td>
</tr>
<tr>
<td>7228/2-1S</td>
<td>Stø</td>
<td>1286-1299</td>
<td>13</td>
<td>0.25</td>
<td>0.16</td>
<td>0.99</td>
<td>0.94</td>
<td>–</td>
</tr>
</tbody>
</table>
Figure 4.6: Composite log plot of the oil saturated reservoir interval in the Stø Formation, together with the underlying Nordmela and overlying Fuglen Formations in well 7324/8-1 (Wisting discovery).

Figure 4.7: Composite log plot of the gas saturated reservoir interval in the Stø Formation, together with the underlying Fruholmen and overlying Fuglen Formations in well 7225/3-1 (Norvarg discovery).
4.2. Discussion

4.2.1. Kobbe Formation

During the deposition of the Kobbe Formation, the Barents Sea comprised a central marine shelf, with land areas to the east, south and northwest. The formation consists of shales, siltstones and sands, deposited in delta-front to shoreface environments. Sediments, derived from provenance areas on the Fennoscandian Shield to the south and the Urals to the east and southeast, were deposited along a NE-SW trending coastline (Smelror et al., 2009). The Kobbe Formation is initiated by marine shales, that develop into interbedded shales, siltstones and carbonate cemented sandstones in an overall regressive trend (Lundschien et al., 2014).

![Palaeogeographic evolution of the Barents Shelf including Svalbard during the Middle Triassic and Late Triassic](image)

Figure 4.8: Palaeogeographic evolution of the Barents Shelf including Svalbard during the Middle Triassic and b) Late Triassic (modified from Lundschien et al., 2014). Red rectangle indicates the study area.

There appears to be a slight cleaning trend toward the eastern part of the study area, with average shale volume decreasing from 60% in well 7324/7-1S to 53% in well 7228/1-1 (Table 4.1). This trend could be explained by increased proximity to the
source area (Urals and the Fennoscandian Shield) of the prograding deltas (Figure 4.8). However, porosity and net-to-gross variations do not show a distinguishable directional trend. Reservoir quality in the study area may be related to the proximity of the source area and the lateral and temporal distribution of sediment-transporting channels.

The reservoir intervals in the Kobbe Formation are thin (∼3-18 m) and display poor reservoir properties. Many of the reservoir intervals, however, are either gas saturated, have minor gas or have hydrocarbon shows. Therefore the potential is there for future hydrocarbon finds, although poor reservoir properties should be expected in the study area.

4.2.2. Snadd Formation

Compared with Kobbe, the Snadd Formation is much cleaner in terms of shale volume, with significantly higher net-to-gross ratios (Table 4.3). In relation to the prograding clastic wedge, the Snadd Formation was deposited in a much more proximal setting, which explains the lower shale volumes (Figure 4.8).

The Snadd Formation is relatively thick and has strong variability in well log responses, which is due to variations in depositional environments. In fact, the depositional environments of the Snadd Formation have been interpreted to range conformably from offshore shale, through to shallow marine, to paralic and fluvial, arranged in discrete stratigraphic sequences. It is expressed as a prograding siliciclastic wedge. The base of the formation starts with relatively distal marine to prodelta shales (through most of the Ladinian section), which then pass into large scale prograding deltaic systems forming the late Ladinian to early Norian sediments (Lundschien et al., 2014).

The formation represents one of the later stages of Early Mesozoic infilling of the Barents Sea Basin. The prograding wedge reached its peak at the Svalbard Archipelago, where time-equivalent Botneheia and De Geerdalen Formations have been uplifted and are exposed (Klausen et al., 2015).

The most striking features of the formation are the recurring relatively thick (up to 58 m in the studied wells) high reservoir quality (average effective porosities between up to 24% in the studied wells) sand intervals, which have been interpreted as being channel sandstone bodies, deposited in an otherwise mudstone dominated coastal plain environment. This description has been given by Klausen et al. (2015) to the thick sand bodies in wells 7324/10-1, 7226/2-1 (Ververis) and 7228/2-1 (see Figure 4.9). These channel sandstone bodies are characterized by rather sharp basal contacts, especially well seen in the density log, where a sudden decrease in density is observed, likely due to the high porosities of the sandstone bodies. The gamma ray log over the intervals commonly has a cylinder to a subtle bell shape, suggesting a fining upwards trend (see also Figure 4.4 and Figure 4.5). Similar well log responses have been observed in the other studied wells and may represent the same type of deposits. The channel sandstone bodies have been described by Klausen et al. (2015) as having a shoestring geometry and extending for several kilometres in length and tens of meters to tens of kilometres in width.

Other, much thinner sandstone bodies, with poorer reservoir qualities, are present
in the Snadd Formation. Some of these intervals have been described by Klausen et al. (2015) as beach ridge sets or barrier beach deposits in a marginal marine and shoreface environment. No attempt at correlating the sand intervals was made in this study as additional constraining data (such as seismics) is needed.

Figure 4.9: Well correlation panels with stratigraphic intervals and facies interpretations for the Snadd Formation. The panels are flattened on the Early Norian MFS (maximum flooding surface) (modified from Klausen et al., 2015). Map indicates the wells in relation to the study area.

Organic rich shales, with both oil and gas prone kerogen, have been described in
the Snadd Formation in wells 7324/10-1 and 7226/2-1 (Ververis) (NPD, 2016). Despite having good reservoir properties and potential source rock intervals, no significant hydrocarbon accumulations have been detected in the Snadd Formation in the studied wells. It is important to study the petroleum systems in order to acquire a more thorough understanding of the factors that may hinder hydrocarbon accumulations (such as the timing of hydrocarbon generation in relation to the trap formation, cap rock sealing capabilities, potential structure tilt and spillage caused by uplift, among other things).

4.2.3. Stø Formation

In all wells, except for 7228/2-1S (Hammerfest Basin), the Stø formation appears to have good reservoir properties, with low shale volume and high porosities. However, in addition to being absent in two of the wells, the average thickness is mostly very thin in comparison to the other formations being evaluated. The average thickness is 28 m.

Figure 4.10: Correlation panels for wells where Stø Formation is present. Map indicates the wells in relation to the study area.
Overall, the Stø Formation is characterised by very low gamma ray log responses, which are commonly the lowest over the entire well log interval. Either Nordmela or Fruholmen Formation underlie the Stø Formation in the study area. A higher gamma ray response is observed in both. The Stø Formation is capped by a clay-rich Fuglen Formation. The transition between the two is characterised by a sudden and sharp increase in gamma ray values (see Figure 4.6 and Figure 4.7).

In terms of characteristic gamma ray log shapes, quite distinct characteristics are observed in each log (Figure 4.10). In the westernmost well, 7324/7-1S, the formation appears to have a general cleaning upwards trend, with at least 4 clear and rather sudden transgressive events, characterized by a sudden increase in gamma ray response (clay volume). In the neighbouring well, 7324/8-1 (Wisting), the gamma ray log shows an initial cleaning upwards trend, followed by a more or less uniform response, without distinct flooding events. Well 7324/10-1 shows two distinct flooding events and a general shallowing upwards trend. Wells 7225/3-1 (Norvarg) and 7225/3-2 (Norvarg) have the thickest Stø intervals. In both wells, the formation can be subdivided into two distinct sequences, separated by sudden sharp decrease in gamma ray readings: (i) a clay-rich lower part, displaying a high gamma ray response, and (ii) a much cleaner upper part. The upper part shows two flooding events in both wells. It could be said that all of the mentioned wells show a shallowing (cleaning) upwards trend. The final well, 7228/2-1S is distinct in this case, showing a gradual increase in the gamma ray response from bottom to top. This well, however, is drilled in the Nordkapp Basin and not on the Bjarmeland platform. The development of the Stø Formation could thus be interpreted as having been different between the two structural elements.

The Late Toarcian, when the Stø Formation was deposited, has been interpreted as having begun as a transgression, which led to a change from flood-plain to prograding coastal depositional environment in the southwestern Barents Sea. Shallow marine depositional environments were later established over most of the basins over the Barents Sea (Smelror et al., 2009).

Olaussen et al. (1984) have studied the depositional environments of the Nordmela and Stø Formations in the Troms I area, to the southwest of this study area. The deposition of Stø Formation above the Nordmela Formation has been interpreted to represent a change from coastal alluvial plain to high-energy coast lines. According to the study, beach ridge and shelf sand deposits form the Stø Formation (Figure 4.11).

The cleaning upwards trends observed in the well log data can be interpreted as having a progradational pattern, associated with progradational coastal environments. The thinner, sudden increases in the gamma ray log may represent short flooding events. It is difficult to determine how extensive such events were and whether they can be correlated between wells. The apparent lack of distinguishable flooding events in well 7324/8-1 (Wisting), however, suggests that they could be local and not very laterally extensive.

The Stø Formation is strongly gas saturated in the upper part in well 7225/3-1 (Norvarg), while in well 7225/3-2 (Norvarg), only approximately 5 km away, is fully water saturated. The formation is encountered several meters shallower in well 7225/3-1 (Norvarg) and therefore could represent a structural hydrocarbon trap (anticlinal trap.
associated with the Norvarg Dome). The depth of the Stø Formation also increases from west to east towards the Hoop Fault Complex in the westernmost part of the study area. The oil find in well 7324/8-1 (Wisting) can potentially increase the optimism of finding more reservoirs, with fault surfaces acting as impermeable barriers, hindering further hydrocarbon migration.

**Figure 4.11:** A reconstruction of the depositional environment of the Nordmela and Stø Formations (from Olaussen et al., 1984).
4.3. Uncertainties

Petrophysical analysis is an important interpretation procedure, which provides primary input data for characterisation of subsurface formations and evaluation of resources. Common data that is extracted is porosity, water saturation, permeability, lithology and mineral types, none of which can be directly measured by the well logging tools. The needed information is derived through multiple steps, which involve tool calibration, data acquisition, processing, and geophysical and geological interpretation. Each step has its own attached uncertainties and limitations, which must be understood both for assisting interpretation and understanding its constraints (Moore et al., 2011). As the results of the petrophysical evaluation are used in order to study the link between reservoir properties and rock physics trends, it is important to consider the potential sources of error which can later be reviewed. The main uncertainties involved in the petrophysical analysis of this study are summarized below.

4.3.1. Acquisition

All geophysical tools used during data acquisition have uncertainties associated with the actual production of the tool. These are addressed by the manufacturers, which commonly provide documentation of certain boundaries between which the tool can be expected to err and its resolution. The tools must also be calibrated against certain standards before use. These issues are not addressed in this study.

The acquisition environment (in this case, the borehole) introduces additional uncertainties. The immediate formation around the borehole is subject to mechanical and physical damage. Mechanical damage is associated with the changes in stress fields due to the creation of the actual hole and the vibrations of the drilling tool, and can create fractures and holes around the borehole. Chemical damage is associated with the chemical reaction of drilling fluids with the formation. As an example, smectite is known to be able to absorb water easily, increase in volume (swell) and cause problems in the borehole. In uneven borehole environments, the logging tools may not be in contact with the formations and their readings might need correction (Rider and Kennedy, 2011). This has been discussed in more detail in Section 3.2. Commonly, the geophysical companies performing the acquisition provide well log data corrected for borehole conditions. However, when caving is too large, it is not possible to correct the data with an acceptable uncertainty.

In this study, the largest borehole problems occurred in Snadd and Kobbe Formations in well 7228/2-15, where a significantly over-gauged hole was observed in the caliper log data. Significant kicks in log responses were observed over these formations, and petrophysical evaluation results showed strong discrepancies between this and the neighbouring wells. Results of petrophysical analysis were therefore considered unreliable and were excluded from the results.
4.3.2. Shale volume estimation

Several non-linear relationships exist which attempt to address the often non-linear relation between the gamma ray response and shale volume (see also Section 3.4.1.1). After trying several published relations, the linear relationship was chosen to represent the best estimation of shale volume, due to close agreement with the neutron-density method. Lack of core data means that the relation cannot be tested. If the linear relationship does not represent the actual formations to an acceptable degree of error, significant misinterpretation can occur as the shale volume becomes an important input for further study (for example, for effective porosity estimations, reservoir cutoffs, and as a lithology indicator in the rock physics diagnostics).

The issue was addressed to some extent by using the gamma ray together with the neutron and density measurements. The uncertainties of one method were more or less compensated by the other. For example, very high gamma ray responses, associated with organic rich shales, were regarded as not being representative of a typical shale and the shale volume derived from the neutron-density method was used instead.

Wells 7226/2-1 (Ververis) and 7228/1-1 showed a much larger gamma ray count in comparison to the same formations in other logs – a response which cannot be explained by natural variations in radioactivity. This could have been caused by the use of more sensitive tools or a more radioactive drilling fluid. Despite this, it was considered that the same relationships between the gamma ray response and formation shaliness still hold and the ‘clean sand’ and ‘pure shale’ points were simply shifted towards higher values.

4.3.3. Porosity

In this study, both total and effective porosities were computed. In both cases, the root mean square of both the neutron and density derived porosities was used for the final porosity estimation, assuming that some of the inherent uncertainties from one method were compensated to some degree by the other method. Uncertainties of both neutron and density derived porosities are described in more detail in Section 3.4.3.

For calculations of effective porosity, a shale term was added to both the density and the neutron porosity method. For the density porosity method, both the volume of shale and its density must be estimated for effective porosity calculations (see Section 3.4.3.2 and Section 3.4.3.3). For the neutron method, the neutron reading in wet clay must be estimated. In both cases, the additional assumptions may lead to errors in the interpretation.

4.3.4. Water saturation

The Archie equation was used for saturation estimations in this study. The equation works well in rocks with simple, uniform pore systems, filled with saline water, but corrections for clay bound water must be made in shaly formations (Ellis and Singer, 2008). In addition, quite a few variables exist in the equation, which need to be measured or assumed. Explanation of the Archie equation is given in Section 3.4.4. Assumptions of the various parameters, leading to uncertainties are listed below:
• Water resistivity was derived from the Pickett plot. It requires finding a brine saturated zone, where formation water resistivity can be computed. However, it is not always clear whether a particular interval is fully brine saturated. Even small amounts of hydrocarbons can increase the resistivity readings and lead to misinterpretation.

• The estimated water resistivity was assumed not to vary significantly within a formation, which may not always be true.

• Typical values for the cementation exponent \( (m = 2) \), saturation exponent \( (n = 2) \) and tortuosity factor \( (\alpha = 1) \) were assumed. Each of these values may vary between reservoir intervals and cause errors in saturation estimations.
CHAPTER 5

Rock Physics Diagnostics

The results of the rock physics interpretation are presented and discussed in this chapter. To begin with, the effects of saturation, clay minerals, porosity and other parameters on the seismic properties \(V_P\), \(V_S\), and \(\rho\) of a sedimentary rock are discussed and shown in various crossplots. Depositional and diagenetic trends in reservoir intervals are then assessed with the help of rock physics effective medium models and referred to published literature. Other rock physics crossplots, such as ‘\(V_P/V_S\) versus AI’ and ‘Lambda-Mu-Rho’, are used for distinguishing lithology and saturation. Finally, uncertainties associated with using rock physics models and templates to infer various reservoir parameters and their applicability in the study area are discussed.

5.1. Fluid and Clay Effects on Seismic Parameters

5.1.1. Fluid effect

When plotting \(V_P\) against \(V_S\), it is often observed that the data tend to fall along a narrow linear trend, despite variations in porosity, clay volume and pore pressure. All three parameters have a similar enough effect on both \(V_P\) and \(V_S\), that data points tend to cluster along a relatively narrow trend for brine saturated rocks. However, changes in fluid saturation often have a remarkable effect of moving data towards another trend, so that, for example, data points from gas saturated sands will cluster along a different trend line than for water saturated sands (Avseth et al., 2005). Examples of this can be seen in data from wells 7225/3-2 (Norvarg appraisal) and 7226/2-1 (Ververis discovery), where gas has been found in the sandstones of the Kobbe Formation (Figure 5.1). Here, data points from the entire Kobbe Formation are plotted.

Despite the various competing velocity influencing parameters in the Kobbe Formation, the non-fluid effects are similar enough that data points have a rather tight fit around a certain trend line. Change in saturation, however, moves data points from one trend to another.

It is important to note that with increasing rock matrix stiffness, the effect of
Figure 5.1: Gas effect on Vp-Vs relation. Note that at low $V_S$-$V_P$ values, even small gas saturations allow for good fluid discrimination (seen in well 7225/3-2 (Norvarg), left). Data color coded by water saturation ($S_{sw}$).

Figure 5.2: Compaction effect on $V_P$-$V_S$ values. Increase in $V_P$ and $V_S$ values with depth in the gas saturated sandstones is attributed to porosity loss, likely caused by increased cementation. This trend is not seen in brine saturated data with high shale volume. KMBSF – kilometres below sea floor.
fluid on the elastic waves becomes increasingly smaller. Therefore gas saturated data points become increasingly more difficult to discriminate, and shear wave information becomes less valuable. In the general case, compaction tends to increase with depth due to higher pressure and temperatures (unless processes, such as overpressure, coating or other factors hinder compaction). By plotting the same Kobbe intervals in a $V_S$ versus $V_P$ plot, now colour-coded for depth, a clear trend of increasing $V_P$ and $V_S$ with depth becomes evident in the gas saturated sandstone intervals (see Figure 5.2). In both wells, the porosity and shale volume vary between gas saturated reservoirs, but there is a general trend of porosity decrease with depth, while the shale volume seems to be variable (see Table 4.2). Pore pressure and the degree of compaction are unknown. It could be argued that because the estimated shale volume does not have a clear correlation with the estimated porosity, the loss of porosity with depth is due to compaction (possibly increased cementation). Increase in compaction would stiffen the rock matrix, moving the data points toward higher $V_P$-$V_S$ values. The degree of cementation in the reservoirs is further discussed in Section 5.2.1.

The trend of increasing $V_P$-$V_S$ values is not observed in the brine saturated data points, which mostly comprise shales and sandy shales. However, a general increase in shale volume is observed with decreasing $V_P$-$V_S$ values. Clay tends to decrease velocity and the volume of clay in the brine saturated data points may be the factor controlling $V_P$-$V_S$ values. Other factors that may have a significant effect are variations in porosity and pore pressure (Avseth et al., 2005).

5.1.2. Clay effect

It is known that a large part of the scatter in the velocity-porosity relationship can be attributed to clay content. If we assume that for shaly sands, clay particles are part of the pore space, then total porosity will decrease with increasing clay content in a linear fashion. This will make the rock stiffer and increase velocity. When the porosity is completely filled with clay, any addition of more clay minerals will make clay part of the rock matrix, as the sediments become clay-supported. Since clay is softer than sand, velocity will start to decrease with increasing amount of clay (Marion et al., 1992).

To study the effect of clay on the velocity and porosity, data points of the Snadd and Kobbe Formations from selected wells have been plotted in the $V_P$ versus porosity plot and colour coded by estimated shale volume (see Figure 5.3). A characteristic inverted V-shape trend is observed, with increasing shale volume, where velocity reaches a maximum and porosity reaches a minimum at approximately 40-50% estimated shale volume. Following the theory proposed by Marion et al. (1992), this zone should represent the transition between grain-supported to clay-supported matrix. The upper overlaid line represents a 2% cement clean sand model, and the lower – a constant clay model, with 80% clay and 20% quartz. Both model lines have been digitized from Avseth et al. (2005).

The cleanest intervals in the Snadd Formation are observed to cluster around the 2% cement clean sandstone line, especially in the high porosity range. This is in contrast to the cleanest Kobbe data points, which mostly plot below this model line. The lower $V_P$ values can be attributed to the effect of gas, as all the cleanest reservoir intervals
in the Kobbe Formation in well 7225/3-2 (Norvarg discovery) have been interpreted earlier to have some amount of gas saturation (Figure 5.1). For both formations, the constant clay line is observed to significantly underestimate the velocities of shales. This suggests that the shales are more compacted than the model predicts.

It is evident from examples such as the one in Figure 5.3 that variations in shale volume have a significant effect on the seismic velocities, especially when moving from grain to clay supported matrix. Attempts have also been made by different authors (Han et al. (1986); Marion et al. (1992) and others) to use this effect in order to estimate clay volume in reservoir rocks. The increasing clay content tends to make the rock softer, while the reduced porosity makes the rock stiffer. The counteracting effects tend to produce a nearly linear trend, which allows the clay volume to be estimated (Dvorkin et al., 2014). Estimations are made by using the P- or S-wave velocity versus porosity crossplot. Modelled constant-clay (or constant-shale) lines are plotted together with the data points. These lines are then used to define subfacies of sands, where the change in facies is associated with varying amounts of clay/shale. The constant-clay lines can be modelled similarly to the friable-sand model, by using modified Hashin-Shtrikman lower bound (Avseth et al., 2005). Another option is to use published empirical P-wave (or S-wave)-porosity-clay trends by, for example, Han et al. (1986) or Tosaya and Nur (1982).

Empirical lines were used to predict the volume of shale in selected reservoir intervals of the Snadd Formation (see Figure 5.4). Snadd Formation data points from all wells (except 7228/2-1S, where the Snadd Formation is deeply buried, with top Snadd at 1150 MBSF) were plotted in the depth range of 400-800 MBSF (meters below sea floor), and filtered to include only those with 0-50% shale. Empirical constant-clay lines for the 5 MPa case (which corresponds to 500 m burial depth, assuming a 10 kPa/m pressure gradient) by Han et al. (1986) are overlaid in the plot. The data points were colour coded by shale volume. Nearly all data points were observed to plot within the model lines. However, with a large amount of data plotted, a good discrimination between data points with different amount of shale did not occur,
Figure 5.4: Clay volume prediction using $V_p$ versus $\phi$ plot. 0-50% $V_{sh}$ Snadd intervals in the depth range of 759-775 MBSF (from wells 7324/7-1S, 7324/8-1 (Wisting), 7324/10-1, 7225/3-1 (Norvarg), 7225/3-2 (Norvarg) and 7228/1-1 (dry)) are plotted on the left. On the right, a Snadd interval in the depth range of 759-775 MBSF from well 7228/1-1 is shown. Empirical lines for 5 MPa confining pressure by Han et al. (1986) are overlaid.

although a slight trend of increasing $V_p$ and decreasing porosity was observed going from lower to higher shale volumes. An attempt was also made to plot data points from each individual well. A Snadd formation interval in the depth range of 759-775 MBSF is shown on the right side in Figure 5.4. This time data points are observed to have a close agreement with the model by Han et al. (1986).

The lack of differentiation of the data points with varying shale volume in figure Figure 5.4 could be attributed to several factors:

- $V_{sh}$ estimations may be misleading, due to the uncertainties of petrophysical analysis.
- Residual gas saturation may significantly reduce $V_p$.
- Clay volume is assumed by the empirical lines of Han et al. (1986), whereas shale volume was estimated in this study.
- The empirical lines by Han et al. (1986), by nature, are only strictly applicable to set of rocks that were studied by the authors.
- Variability in mineralogy, pore geometry, degree of consolidation, cementation, confining pressure, pore fluid, pore pressure, and temperature may all have various effects on the P-wave and porosity, which are not taken into account.

Empirical equations for shale/clay volume prediction in the $V_p$ versus porosity plot should only be attempted with great care. Although porosity and shale volume strongly affect velocities, complex mineralogy and geological history should always be taken into consideration.
5.2. Results

5.2.1. Estimation of cement volume

Rock physical properties, such as velocity and bulk density, change in response to compaction and diagenetic processes in sedimentary basins. Marcussen et al. (2010) have studied the effects of mechanical compaction and quartz cementation on P-wave velocity and density in the sandstones from the shallow marine Etive Formation of the Brent Group from the northern Viking Graben. They have found that the increase in P-wave velocity with associated increase in quartz cementation fits rather well along a linear trend line, which can be used to estimate roughly the percentage of quartz cement. The trend line has been digitized from their published paper, which gave the following equation:

\[ V_P = 86.60 \times Q + 2773.73 \]  

where, \( Q \) – percentage quartz cement volume; \( V_P \) – P-wave velocity in m/s.

The Etive formation is part of the Brent Group – a major river-delta system that contains very large hydrocarbons reservoirs in the North Sea (NPD, 2016). Marcussen et al. (2010) claim that a strong correlation between quartz cement amounts and velocities exist in the Etive Formation. Therefore, it is interesting if this or similar relationship can be applied in other reservoirs, such as in the Barents Sea.

Another option is to use rock physics cement models, as described in Section 3.5.3. These models are more elaborate and have the potential, with good local validation, to take both the degree of cementation and sorting into consideration (Avseth et al., 2009). In the following, the degree of cementation and sorting in reservoir intervals of the three formations are studied using rock physics models.

In this study, the friable sand model was used in order to display the sorting trend lines. Lines for 1, 10 and 20 MPa (corresponding to depths of 100, 1000 and 2000 m burial depth, assuming a 10 kPa/m pressure gradient) cases were produced following the procedure described in Section 3.5.4. The constant cement and contact cement lines were digitized from Avseth et al. (2005) for the \( V_P \)-porosity plot, and from Avseth et al. (2009) for the \( V_S \)-porosity plot.

5.2.1.1. Kobbe Formation

For a first look analysis, all of the reservoir intervals of the Kobbe Formation (see Section 4.1.1) have been plotted in the \( V_P \) versus porosity and \( V_S \) versus porosity plots together with the effective medium model lines (Figure 5.5). The depth of these intervals has a range of approximately 1100-1700 MBSF and corresponds to approximately 11-17 MPa effective pressure.

According to the friable sand model, unconsolidated, brine saturated sandstones buried to such depths would be expected to plot between the 10 and 20 MPa sorting trend lines, as used in this study. In fact, most of the data points are observed to plot along the diagenetic trend lines in the \( V_P \)-porosity plot, suggesting that the reservoirs are cemented. In the \( V_S \)-porosity plot, the three black lines correspond to approximately 3, 5 and 7% quartz cement from the lowermost to the uppermost, respectively, as shown
in Avseth et al. (2009). The 20 MPa friable sand line also corresponds to the 1% constant cement line in the same article. Most reservoir intervals in the Kobbe Formation are observed to plot between 1-5% constant cement lines in the $V_S$-porosity plot.

Figure 5.5: Diagnostic rock physics models superimposed on all reservoir intervals in the Kobbe Formation. In-situ $V_P$ and $V_S$ values were used. Nearly all reservoirs have some gas saturation, with minimum $S_w = 0.51$.

The 3 reservoir intervals in the Kobbe Formation in well 7225/3-2 (Norvarg) (1593-1608, 1777-1793 and 1910-1928 meters MDKB) were chosen for a closer analysis. The intervals are described by NPD (2016) as ‘Channel A’, ‘Channel D’ and ‘Anomaly 2’, respectively. The same names are used here when referring to these reservoirs.

Both $V_P$- and $V_S$-porosity plots were made and colour coding by $V_{sh}$, depth and cement percentage (estimated from Equation 5.2.1.1) was used (Figure 5.6). A general increase in both $V_P$ and $V_S$ is observed going from the shallowest to the deepest reservoirs.

The cleanest reservoir sands with up to 10% $V_{sh}$ in ‘Channel A’ plot between the 3-5% constant cement lines in the $V_S$-porosity plot, while Equation 5.2.1.1 returns results of between 7.5-9.5% cement. An increase in cement amount with increasing depth is predicted by Equation 5.2.1.1, with ‘Channel D’ predicted to have between 7.5-11.5% cement and ‘Anomaly 2’ predicted to have between 9.5-14% cement. In the $V_S$-porosity plot, however, the deeper ‘Channel D’ and ‘Anomaly 2’ scatter around the 3% constant cement line. When color coded for shale volume, a sorting trend is observed, with cleaner points plotting towards the lower right of the plot (higher $\phi$, lower $V_P$) and more shaly points plotting toward lower $\phi$ and higher $V_P$ values.

In the $V_P$-porosity plot, all three reservoirs are seen to plot along the diagenetic trend line. Increasing diagenetic effect with depth is predicted by the model line. However, gas saturation is expected to reduce $V_P$. 
Figure 5.6: Diagnostic rock physics models superimposed on gas saturated reservoir intervals ‘Channel A’ (average $S_w = 0.51$), ‘Channel D’ (average $S_w = 0.55$) and ‘Anomaly 2’ (average $S_w = 0.66$) from the Kobbe Formation in well 7225/3-2 (Norvarg).
5.2.1.2. Snadd Formation

All of the reservoir intervals, distinguished in Section 4.2.2, have been plotted in the $V_p$ versus porosity and $V_S$ versus porosity plots together with the effective medium model lines (Figure 5.7) for a first-look analysis. These reservoir intervals have a depth range of approximately 300-1200 MBSF, which corresponds to 3-12 MPa effective pressure.

For unconsolidated, brine saturated quartz sandstones, buried to these depths, the data points would be expected to plot between the 1-10 MPa (and slightly above) sorting trend lines, as used in this study. Similarly to the Kobbe Formation, most of the data points are observed to plot along the diagenetic trend lines in the $V_p$-porosity plot. Most of the data points are seen to plot between the 10 MPa friable sand line and the 5% constant cement line in the $V_S$-porosity plot.

![Figure 5.7: Diagnostic rock physics models superimposed on all reservoir intervals in the Snadd Formation. All reservoirs are brine saturated, but residual hydrocarbons are known to occur in some intervals.](image)

Well 7226/2-1 (Ververis) was selected for closer analysis, as it has the thickest reservoir intervals of the Snadd Formation, compared to other wells. Reservoirs in this well have a depth range of approximately 650-1050 MBSF, corresponding to 6.5-10.5 MPa effective pressure range.

Overall, most of the data points from the reservoirs in this well are clustered around the 3% constant cement line in the $V_S$-porosity plot. Increasing amounts of shale are observed to drag the data points along this line towards lower $\phi$ and higher $V_S$ values. In the $V_p$-porosity plot, increasing shale has the effect of dragging data points from the higher, to the lower diagenetic trend. No clear depth trend is observed. In contrast, Equation 5.2.1.1 predicts cement volume in the range of 0-25%.
Figure 5.8: Diagnostic rock physics models superimposed on the fully brine saturated reservoir intervals of the Snadd Formation from well 7226/2-1 (Ververis).
5.2.1.3. Stø Formation

Reservoir intervals distinguished in Section 4.2.3, have been plotted in the $V_p$ versus porosity and $V_S$ versus porosity plots together with the effective medium model lines (Figure 5.9) for a first-look analysis. These reservoirs have a depth range of approximately 200-900 MBSF, corresponding to 2-9 MPa effective pressure.

For unconsolidated, brine saturated quartz sandstones, buried to these depths, the data points would be expected to plot between the 1-10 MPa sorting trend lines, as used in this study. In contrast to the other formations, most of the data points are observed to plot toward the lower model lines, although a large scatter is observed. Most of the data points are scattered from below the 10 MPa sorting line to the 3% cement line in the $V_S$-porosity plot.

Figure 5.9: Diagnostic rock physics models superimposed on the reservoir intervals in the Stø Formation, where both $V_p$ and $V_S$ data is present. The formation is oil saturated in well 7324/8-1 (average $S_w = 0.03$) (Wisting), has hydrocarbon shows in well 7228/2-1S and is brine saturated in other wells.

Well 7225/3-2 (Norvarg) was selected for a more detailed analysis, because it was found to have the thickest clean sand interval and is fully brine saturated, therefore the hydrocarbon effect is avoided. The Stø Formation reservoir interval in this well has a depth range of 323-349 MBSF, corresponding to around 3-3.5 MPa effective pressure. The data is observed to plot along the 10 MPa sorting trend line in the $V_S$-porosity plot and along the 20 MPa line in the $V_p$-porosity plot. Increasing shale volume is observed to drag the data points along the sorting lines toward lower $\phi$ and higher $V_S$ values. Equation 5.2.1.1 predicts cement volumes in the range of 0-12%, with most data points showing a range of 0-5% cement.
Figure 5.10: Diagnostic rock physics models superimposed on the reservoir interval of the Stø Formation in well 7225/3-2 (Norvarg).
5.2.2. Vp/Vs versus AI

The V_p/V_s versus AI template is often used for the purpose of discriminating lithology, porosity and saturation. Each of these parameters tends to drag the data points along certain characteristic trend lines, as discussed in Section 3.5.8 of the ‘Methodology and theoretical background’ chapter.

In this study, rock physics templates showing porosity, lithology and fluid trends were created and applied on the reservoirs in each formation. The input for effective pressure was calculated from the average depth of the reservoir intervals, assuming a 10 kPa/m pressure gradient. The bulk modulus for formation water was assumed to be 2.5 GPa, while the bulk and shear moduli, and density of the rock matrix grains were assumed to be 37 GPa, 44 GPa and 2.65 g/cm², respectively. For a more detailed description on the construction of the rock physics template, the reader is referred to Section 3.5.8.

5.2.2.1. Kobbe Formation

Kobbe Formation in well 7225/3-2 (Norvarg) was chosen for the study using the rock physics template, as it had the best quality reservoir intervals compared to other wells. The 3 thickest intervals in this formation have been found to have high gas saturations of up to approximately 50% (‘Channel A’ average S_w = 0.51, ‘Channel D’ average S_w = 0.55, and ‘Anomaly 2’ average S_w = 0.66). Reservoir intervals here have a depth range of around 1200-1500 MBSF, corresponding to 12-15 MPa effective pressure. 13.5 MPa effective pressure was used as input for the clean sand model line creation.

![Figure 5.11](image.png)

**Figure 5.11:** Kobbe Formation from well 7225/3-2 (Norvarg appraisal) plotted in the V_p/V_s versus AI domain. Points are colour coded by shale volume (left) and total porosity (right). Reservoir intervals have up to 50% gas saturation in this well.

The first plot (Figure 5.11) shows the entire Kobbe Formation from well 7225/3-2 (Norvarg), colour coded by V_sh (left) and \( \phi_t \) (right). A very good discrimination between clean and shaly data points is observed, with shale and sandstone plotting along distinctly different trends. In terms of sandstone porosity, a clear separation is
seen when color coded for porosity. However, the model underestimates porosity.

Figure 5.12: Kobbe reservoirs ‘Channel A’, ‘Channel D’ and ‘Anomaly 2’ plotted in the $V_p/V_S$ versus AI domain for the in-situ (average $S_w = 0.51 - 0.66$) (upper left), 100% brine (upper right), 100% gas (lower left), and 100% oil (lower right) cases, color coded for shale volume in well 7225/3-2 (Norvarg appraisal). 30 meters of shale overlying ‘Channel A’ is plotted for reference.

To study fluid effects in the $V_P/V_S$ versus AI domain, fluid substitution was performed on the three gas saturated intervals (‘Channel A’, ‘Channel D’, and ‘Anomaly 2’) in well 7225/3-2 (Norvarg) (Figure 5.12). In addition to the in-situ case (‘Channel A’ average $S_w = 0.51$, ‘Channel D’ average $S_w = 0.55$, and ‘Anomaly 2’ average $S_w = 0.66$), fluid was substituted to include the 100% brine, gas and oil cases. 30 m of shale cap-rock, overlying the uppermost reservoir interval, was plotted for reference.

In the 100% brine case, an increase in both the $V_P/V_S$ ratio and P-impedance was observed. Brine substituted data points mostly plotted below the sand model line. For the 100% gas case, data points were dragged down further along the gas saturation model line. Nevertheless, most of the data plotted above the 100% gas saturation point. Finally, the 100% oil saturated points plot similarly to the in-situ case.
5.2.2.2. Snadd Formation

Snadd Formation in well 7226/2-1 (Ververis) was chosen to study here, due to it having the thickest reservoir intervals compared with the other wells. All of the reservoir sandstones were found to be fully brine saturated, during petrophysical analysis. Reservoir intervals here have a depth range of around 650-1050 MBSF, corresponding to 6.5-10.5 MPa effective pressure range. 8.5 MPa effective pressure was used as input for the clean sand model line creation.

Figure 5.13: Snadd Formation from well 7225/3-2 (Norvarg) plotted in the $V_p/V_S$ versus AI domain. Points are colour coded by shale volume (left) and total porosity (right).

The first plot (Figure 5.13) shows the entire Snadd Formation from well 7226/2-1 (Ververis), colour coded by $V_{sh}$ (left) and porosity (right). 30 meters of overlying sandy shale data was also plotted for reference. A good discrimination between clean and shaly data points is observed, with shale and sandstone plotting along different trends. This time, the cleanest sand data points plot only slightly below the sand model line, for the most part. In terms of porosity of the sands, a clear discrimination is seen in terms of color coding of the data. However, the model line underestimates the porosity, especially in the high porosity range.

To study fluid effects in the $V_p/V_S$ versus AI domain, fluid substitution was performed on the thickest Snadd reservoir interval in well 7226/2-1 (Ververis) (1361-1419 meters MDKB) (Figure 5.14). For the in-situ case ($S_w = 1$), data points cluster around the sand model line. For both the 10 and 100% gas saturated cases data points are dragged down the gas saturation model line by a similar amount. A much smaller gas effect is observed from the fluid substitution than predicted by the model. In the 100% oil saturated case the data points are also observed to plot down along the the gas saturation model line, but the effect is smaller than for both the 10 and 100% gas saturated cases.
Figure 5.14: Snadd reservoir in the depth range of 1361-1419 MDKB from well 7226/2-1 (Vereris) plotted in the $V_p/V_s$ versus AI domain for the in situ ($S_w = 1$) (upper left), 100% oil (upper right), 10% gas (lower left), and 100% gas (lower right) cases, colour coded for shale volume. 30 meters of overlying shaly sediments are plotted for reference.
5.2.2.3. Stø Formation

Stø Formation in well 7225/3-2 (Norvarg) was chosen to study here, due to it having the thickest reservoir interval compared with the other wells. The reservoir was found to be 100% brine saturated during petrophysical analysis. Depth ranges between 330-355 MBSF, corresponding to 3.3-3.6 MPa effective pressure. 3.5 MPa effective pressure was used as input for the clean sand model line creation. The Fuglen Formation was plotted for reference as a cap rock (Figure 5.15).

![Graph showing Stø Formation from well 7225/3-2 (Norvarg) plotted in the $V_p/V_s$ versus AI domain. Points are colour coded by shale volume (left) and total porosity (right).](image)

The reservoir sands cluster around the model line. Porosities are underestimated by the model line, especially towards the higher range.

The same reservoir interval was chosen for studying fluid effects, together with the oil saturated reservoir interval in well 7324/8-1 (Wisting discovery) (Figure 5.16). High oil saturation was estimated in this well by petrophysical evaluations ($S_w = 0.03$). 100% gas substitution in well 7225/3-2 (Norvarg) drags data points well along the gas saturated model line, although not as much as the model predicts. 100% oil saturation has a lower effect, with data points plotting in between the fully brine and fully gas saturated cases. For the actual oil saturated case, in well 7324/8-1 (Wisting), the fluid effect is lesser than that predicted by fluid substitution for 100% oil in well 7225/3-2 (Norvarg).
Figure 5.16: Stø reservoir in the depth range of 729-755 MDKB from well 7225/3-2 (Norvarg) plotted in the $V_p/V_s$ versus AI domain for the in-situ ($S_w = 1$) (upper left), 100% gas (upper right) and 100% oil (lower left) cases; and the oil saturated Stø reservoir in the depth range of 662-679 MDKB for the in-situ case (average $S_w = 0.03$), colour coded for shale volume. The overlying shale of the Fuglen Formation is also plotted for reference.
5.2.3. Lambda-Mu-Rho

Although general guidelines for lithology and fluid classification using Lamé’s parameters can be derived, it is important to model particular reservoir zones in order to characterize specific areas. In the following, selected reservoir and shale intervals are plotted in the LMR domain and fluid sensitivity is observed by comparing to the threshold cutoff for gas sands by Goodway, 1999.

The $\lambda$ parameter represents the incompressibility, which is decreased due to gas saturation. The rigidity parameter, $\mu$, has a negligible sensitivity to the fluid type. This should allow gas saturated sandstones to be discriminated from the brine saturated sandstones in the LMR domain. For a more detailed description on the theory behind ‘Lambda-Mu-Rho’, the reader is referred to Section 3.5.9 of the ‘Methodology and theoretical background’ chapter.

5.2.3.1. Kobbe Formation

![Figure 5.17: Entire Kobbe Formation plotted in the LMR domain for well 7225/3-1 (Norvarg discovery, upper left) and 7225/3-2 (Norvarg appraisal, lower left), colour coded for shale volume; and Data points from the Kobbe Formation filtered for $V_{sh} \leq 40\%$ for well 7225/3-1 (Norvarg) (upper right) and 7225/3-2 (Norvarg) (lower right), colour coded for water saturation.](image-url)
Kobbe Formation from wells 7225/3-1 (Norvarg discovery) and 7225/3-2 (Norvarg appraisal) were chosen for study in the LMR domain (Figure 5.17). Gas saturated reservoir intervals are found in both wells, with average gas saturation up to 0.51 in well 7225/3-1 (Norvarg) and up to 0.55 in well 7225/3-2 (Norvarg), estimated from petrophysical analysis. A good discrimination between shales and sands is observed in the plots. There is also a clear saturation trend in the reservoir sandstones, where an increase in gas saturation has the effect of dragging data points to the left, towards lower $\lambda\rho$ values. It is observed in both cases, that only the most gas saturated data points, with $S_w$ of approximately 40-50%, plot to the left of the threshold line (threshold cutoff for porous gas sands, from Goodway, 1999).

### 5.2.3.2. Snadd Formation

Snadd Formation from well 7226/2-1 (Ververis) was chosen for study in the LMR domain (Figure 5.18). The formation has, in total, around 160 m of reservoir sand. A good discrimination between shales and sands is observed in the LMR plot. All reservoir intervals here are fully brine saturated. To observe fluid effects, fluid substitution was performed on the 1361-1419 m MDKB interval ($S_w = 1$), substituting for 100% gas. The reservoir is now observed to plot well to the left of the threshold line (threshold cutoff for porous gas sands, from Goodway (1999)).

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**Figure 5.18:** Entire Snadd Formation plotted in the LMR domain for well 7226/2-1 (Ververis) (left); and the same with a reservoir interval in the depth range of 1361-1419 m MDKB fluid substituted for a 100% gas case.
5.2.3.3. Stø Formation

Stø Formation from wells 7225/3-2 (Norvarg) and 7324/8-1 (Wisting discovery) were chosen for study in the LMR domain, together with the overlying shales of the Fuglen Formation (Figure 5.19). The reservoir is fully brine saturated in well 7225/3-2 (Norvarg) and oil saturated ($S_w = 0.03$) in well 7324/8-1 (Wisting). In the LMR domain, there is no good fluid discrimination, with both brine and oil saturated data plotting similarly. When colour coded by depth, a general trend of increasing $\lambda \rho$ and $\mu \rho$ with depth is observed.

Figure 5.19: Entire Stø ($S_w = 1$) and Fuglen Formations plotted in the LMR domain for well 7225/3-2 (Norvarg), colour coded for depth in meters below sea floor (upper left) and shale volume (upper right); and entire Stø (Wisting discovery, $S_w = 0.03$) and Fuglen Formations plotted in the LMR domain for well 7324/8-1 (Wisting), colour coded for depth (lower left) and shale volume (lower right).
5.3. **Discussion**

5.3.1. **Cementation**

Prediction of cement as shown by the rock physics relations should ideally be verified with thin-section analysis. Unfortunately, thin sections were not examined in this study due to time constraints. Instead, results of cementation analysis are discussed in relation to studies published by Line (2015), Net et al. (2015), and Porten (2012), which performed thin section analyses in the Kobbe, Snadd and Stø Formations, albeit in wells outside this study area.

5.3.1.1. **Kobbe Formation**

![Figure 5.20: Thin sections from the sandstones of Kobbe Formation in well 7222/11-2. a) Chlorite coating surrounding the grains (depth = 2120.8 MD); b) quartz overgrowth on grains, where chlorite coating is absent (depth = 2120.8 MD) (taken from Line, 2015). The map shows the location of the well in relation to the study area.](image)

Thin sections from the Kobbe and Snadd Formations from wells located in the Fingerdjupet Sub-basin, Loppa High and Nordkapp Basin, southwestern Barents Sea, were studied by Line (2015). The study found that the studied Kobbe sandstones had up to 67% quartz grains. Feldspar, rock fragments and other minerals were also present in the sandstones. The study found up to 5% quartz cement. Chlorite coating was found to be an important porosity preserving mechanism in this formation, with quartz overgrowth found on grains where chlorite coating was sparse or absent. In
addition, up to 2% calcite cement and up to 6% siderite cement was observed (see Figure 5.20).

In this study, the reservoir sandstones of the Kobbe Formation were found to plot mostly between the 1-5% quartz cement lines in the ‘$V_S$ versus $\phi$’ plot. This is a very similar result to that of the study by Line (2015). Nevertheless, the rock physics models used in this study were produced by assuming a simplistic case of a brine saturated sandstone, and were not calibrated against data from thin sections from the studied wells. It is clear that effects of other the different types of minerals and cement types must be taken into consideration when producing the rock physics models, before any conclusion about the degree of cementation are made.

Some of the effect of stiffening of the rock frame, that results in data points plotting on the constant cement line, are likely related to other types of cement (calcite, siderite) present in the Kobbe Formation, and lead to overestimation of quartz cement volume. On the other hand, soft rock fragments, which are also described in this formation, may have the effect of reducing velocities and lead to underestimation of quartz cement volume.

5.3.1.2. Snadd Formation

![Figure 5.21](image.png)

**Figure 5.21:** Thin sections from the sandstones of Snadd Formation in wells a) 7222/11-1 and b) 7228/7-1. a) Quartz overgrowths are indicated with red arrows (taken from Porten, 2012); b) chlorite coating on quartz grains. Siderite and rutile also present in the pore space (taken from Line, 2015). The map shows the location of the wells in relation to the study area.

Thin sections from the Kobbe and Snadd Formations from wells located in the
Fingerdjupet Sub-basin, Loppa High and Nordkapp Basin, southwestern Barents Sea, were studied by Line (2015) and Porten (2012).

The study by Line (2015) found a high abundance of lithic rock fragments in the Snadd Formation, which is interpreted to be the source for chlorite coating. The ductile response to deformation in lithic rock fragments is also argued to preserve porosity, as no grain fractures were found to occur. Calcite cement was also observed in this formation (Figure 5.21).

Porten (2012) studied thin sections from wells on the Finnmark Platform and the Loppa High. The study found that chlorite coating was prevalent in the Snadd Formation, which prevented quartz cementation and preserved porosity. Siderite cement was present in amounts of 1-6%, and a few zones were found to be strongly calcite cemented. In addition, up to 3% authigenic kaolin was commonly found as well as traces of pyrite cement and quartz overgrowth (Figure 5.21).

Another study of the reservoir quality of the Snadd sandstones was carried out by Net et al. (2015). The Snadd unit was informally subdivided into two members: (i) the Lower Snadd, which contains lower shoreface and inner shelf deposits, and (ii) the Upper Snadd, which also includes fluvial and fluvio-tidal deposits. In addition, sequence stratigraphic analysis was performed and shelf margin, transgressive and highstand systems tracts were recognised. The authors distinguished two main porosity-preserving diagenetic processes: (i) early precipitation of pore lining/filling siderite cement, which is thought to have hindered further mechanical compaction, and (ii) development of chlorite coatings, which impeded the precipitation of quartz cement. Chlorite coatings were found to be thick and continuous within the shelf margin and transgressive systems tracts, but thin and discontinuous within highstand systems tracts. Average quartz cementation was found to be 2.1% in shelf margin, 9.6% in transgressive, and 5% in highstand systems tracts. The lower percentage of quartz cementation in highstand systems tracts was explained by the presence of other cements, such as calcite (average of 8%). Core porosity was found to increase with increasing amount of chlorite coating. Thin section analysis from the study by Net et al. (2015) is shown in Figure 5.22.

The published works show that quartz cementation is significantly hindered in the Snadd Formation, which is related to different porosity preserving mechanisms, with chlorite coating being arguably the most important factor. The rock physics models used in this study showed up to 5% cement in the reservoir of the Snadd Formation (Figure 5.7). However, the stiffening of the rock frame is likely to be related not only to quartz cement, but also to other types of cement that has been described in this formation (such as siderite and calcite).

The rock physics models used in this study were produced by assuming a simplistic case of a brine saturated sandstone. The estimation of cement volume should therefore not be trusted until thin section analysis is used to verify the results. The elastic properties of the lithic rock fragments and other types of mineralogy and cement present in the sandstones of the Snadd Formation should also be taken into consideration when creating rock physics models.
5.3.1.3. Stø Formation

Thin sections from the Stø Formation in the Hammerfest Basin were studied by Walderhaug and Bjørkum (2003). The study found stylolite spacing to be an important factor on the quartz cement contents, with far less quartz cement found in intervals with exceptionally large stylolite spacing. The study found large variations in quartz cement (6-22%) between samples, although these values are thought to include inherited quartz overgrowths from older sandstones. No calcite cement was observed in the study (see Figure 5.23).

In this study, most of the data points were scattered from below the 10 MPa sorting line to the 3% cement line in the \( V_S \) versus \( \phi \) plot, although, according to the present effective pressure (2-9 MPa), they were expected to plot below the 10 MPa friable sand.
line. The rock physics models therefore suggest some degree of consolidation.

![Figure 5.23: An example of slightly quartz cemented Stø sandstone a); and strongly quartz cemented sandstone b) in well 7120/6-1 (taken from Walderhaug, 1992). The map shows the location of the wells in relation to the study area.](image)

The sandstones of the Stø Formation are much cleaner in terms of mineralogy and shale volume, compared to the sandstones of the Kobbe and Snadd Formations, and are generally classified as quartz arenites (Olaussen et al., 1984). The rock physics models used in this study assumed a brine saturated quartz sandstone and should therefore be more accurate at estimating the effects of compaction and diagenesis in this formation, compared to Kobbe and Snadd. Nevertheless, the rock physics models must ideally always be verified by thin section analysis before their results can be trusted with confidence.

### 5.3.2. Lithology, porosity and fluid sensitivity

The effect of shale volume, porosity, fluid types, and compaction and cementation on the seismic properties have been studied by employing \( V_P/V_S \) versus AI’ and ‘Lamda-Mu-Rho’ crossplots. Shale volume, porosity and water saturation are taken from the results of the petrophysical analysis, while compaction and cementation are inferred from rock physics effective medium models. Fluid substitution was also performed in order to study fluid sensitivity.

#### 5.3.2.1. Kobbe Formation

In terms of lithology, shales and sandstones of the Kobbe Formation were observed to plot along distinctly different trends in both the \( V_P/V_S \) versus AI’ and ‘Lamda-
Mu-Rho’ plots, allowing for a good lithology discrimination (see Figure 5.11 and Figure 5.18).

In the ‘\(V_p/V_s\) versus AI’ plot, the gas saturated reservoir intervals were observed to plot lower than the model sand line (which assumes an unconsolidated, brine saturated quartz sandstone), along the gas saturation model line. However, even though reservoirs had average gas saturations of up to 0.51, data points plotted between the 0-10% gas saturation points (Figure 5.11). This may be related to the effect of clay. Clays have a higher incompressibility than rigidity (\(\lambda > \mu\)), which results in greater \(V_p/V_s\) ratios (Perez and Tonn, 2003). The presence of clay within the reservoirs would therefore be expected to drag the data points closer toward the shale trend in the ‘\(V_p/V_s\) versus AI’ plot, thus reducing the effect of gas. Reservoir intervals in the Kobbe Formation have been estimated to have relatively large volumes of shale, during petrophysical analysis, which supports the assumption of clay reducing the gas effect. On the other hand, the RPT assumes a homogeneous fluid saturation, which results in residual amounts of gas causing almost the same seismic properties as commercial amounts of gas. A patchy distribution would produce a more linear change in seismic properties with increasing gas saturation (Ødegaard and Avseth, 2004). If the fluids in these reservoirs have a patchy saturation, then the model is predicting a much more accurate result.

Fluid substituting the 3 gas saturated reservoirs (average \(S_w = 0.51-0.66\)) in well 7225/3-2 (Norvarg appraisal) for brine had the effect of bringing data points closer towards the model sand line, but the points still plotted below the line and porosities were underestimated (Figure 5.12). As discussed in Section 3.5.8, cementation tends to drag data points towards lower \(V_p/V_s\) and higher AI values, and has the opposite effect of clay. Rock physics cement models predicted some degree of cementation in these reservoirs, which may explain why brine saturated reservoir data plots below the sand model line.

For a fully gas saturated case, most data points were observed to plot above the modelled 100% gas trend. Both the volume of clay and cementation can be invoked in explaining this effect. On the one hand, the presence of clay may increase the \(V_p/V_s\) ratios, dragging data towards the shale cluster. Moreover, even a small degree of cementation is known to have a strong stiffening effect on the rock matrix. This would reduce fluid effect, the \(V_p\) would not be reduced as much, resulting in higher \(V_p/V_s\) ratios.

In the LMR plot, a clear fluid trend is observed, with higher gas saturations resulting in lower incompressibility (\(\lambda\)), but similar rigidity (\(\mu\)) values (Figure 5.17).

### 5.3.2.2. Snadd Formation

In terms of lithology, shales and sandstones are plot along distinctly different trends in both the ‘\(V_p/V_s\) versus AI’ and ‘\(\lambda\)-Mu-Rho’ crossplots, allowing for a good lithology discrimination. The brine saturated reservoir intervals cluster along the sand model line, although porosities are underestimated, especially in the higher porosity range (Figure 5.13 and Figure 5.18).

The degree of cementation is lower in the Snadd Formation, compared to the Kobbe
Formation. The fact that Snadd reservoir sands plot along the model sand line, in
contrast to the Kobbe reservoirs, confirms this. However, a small degree of cementation
is predicted by the rock physics models in the cementation analysis. It could be argued
that the counteracting effects of clay and cement have similar effects on the seismic
properties, that data points remain on the unconsolidated pure sand line.

Fluid substitution results show a lower fluid sensitivity than that predicted by
the model (Figure 5.14). As with the Kobbe Formation, both the volume of clay and
cementation can be invoked in explaining this effect. On the one hand, the presence
of clay may increase the $V_p/V_S$ ratios, dragging data towards the shale cluster. On
the other hand, cementation may have a strong stiffening effect on the rock matrix,
resulting in lower fluid sensitivity and higher than expected $V_p/V_S$ ratios.

30 m of overlying shaly sediments above the reservoir were plotted in Figure 5.14
for the in situ case for reference. The overlying rock is shaly, but probably not a good
cap rock. The data points for this interval plot closer toward the shale cluster, but not
as high as in the case of Kobbe and Stø reservoir intervals.

Fluid substitution was also performed on a fully brine saturated Snadd reservoir
interval in well 7226/2-1 (Verperis). A good fluid discrimination was observed in the
LMR domain, as fully gas saturated data points plotted well to the left of the threshold
cutoff for porous gas sands line from Goodway (1999).

5.3.2.3. Stø Formation

In both the ‘$V_p/V_S$ versus AI’ and ‘Lamda-Mu-Rho’ crossplots, distinctly different
trends were observed for the sands of the Stø Formation and the overlying shales of the
Fuglen Formation (Figures 5.15 and 5.19), allowing for good lithology discrimination.

The brine saturated reservoir interval in well 7225/3-2 (Norvarg) plotted along the
sand model line in the ‘$V_p/V_S$ versus AI’ plot (Figure 5.15), although the porosities
were underestimated in the high porosity range. In the ‘$V_S$ versus $\phi$’ plot, the data
points of this reservoir were observed to plot along the 10 MPa effective pressure
friable sand model line (Figure 5.10). The sandstone intervals here are presently buried
at depths of approximately 350 MBFS, which corresponds to 3.5 MPa effective pressure.
The reservoir can therefore be expected to be more consolidated than is expected at this
depth. If a small percentage of cement is present in the reservoir, this could explain the
porosity underestimation in the high porosity range. A small amount of initial cement
is known to have strong stiffening effect on the rock matrix, without a significant
increase in density. This could produce both a larger impedance and a lower $V_p/V_S$
ratio and lead to underestimation of porosity in the ‘$V_p/V_S$ versus AI’ plot.

Fluid substitution results show a lower fluid sensitivity than that predicted by
the model (Figure 5.16). As with the Kobbe and Snadd Formations, both the volume of
clay and cementation can be invoked in explaining this effect. In addition, the presence
of clay may increase the $V_p/V_S$ ratios, dragging data towards the shale cluster. On
the other hand, cementation may have a strong stiffening effect on the rock matrix,
resulting in lower fluid sensitivity and higher than expected $V_p/V_S$ ratios.

The sandstone of the oil saturated reservoir in well 7324/8-1 (Wisting discovery)
(average $S_w = 0.3$) was observed to have a much lower fluid effect than that predicted
by fluid substitution in well 7225/3-2 (Norvarg) (Figure 5.16). This effect may be related to the oil having similar seismic properties to that of brine. Denser oils would not show a strong fluid effect compared to lighter oils.

One striking feature about the reservoir interval in well 7324/8-1 (Wisting discovery) is the scatter of data points in the high $V_P/V_S$ ratio and high P-impedance range in the $V_P/V_S$ versus AI' plot (Figure 5.16). The scatter is caused by ‘kicks’ in the $V_P$ and density logs, which are also observed in the deep- and microresistivity logs (Figure 5.24). These may be associated with thin intervals of different lithology, such as evaporites or carbonates, or the effect may be caused by significantly cemented intervals. As discussed in Section 5.3.1.3 the study by Walderhaug and Bjørkum (2003) has found large variations in quartz cement (6-22%) between samples of the Stø sandstones within one well. Large differences in the degree of cementation could explain the well log behaviour.

![Figure 5.24](image)

Figure 5.24: ‘Kicks’ in the velocity and density, deep- and microresistivity logs in the Stø Formation in well 7324/8-1 (Wisting), highlighted in yellow.
5.4. Uncertainties

- The rock physics effective medium models used in this study have been produced assuming unconsolidated, brine saturated, medium grained quartz sandstone with spherical grains. This may be a valid approximation for clean sandstones with dominating quartz mineralogy, however, for more complex geological scenarios more elaborate models should be used, that incorporate all available information. In fact, geological constraints that must be considered for the creation of rock physics models include lithology, mineralogy, burial depth, diagenesis, pressure and temperature (Ødegaard and Avseth, 2004). The type of saturating fluid also has a significant effect.

- In this study, effective pressure estimated from the current depth was used as input for the creation of rock physics models for simplicity. However, the study area has been subjected to significant uplift in recent geologic history. The expected degree of compaction and consolidation should be taken into consideration when producing rock physics models.

- The results of estimated degree of compaction and cementation could not be verified by thin section analysis, which is necessary for constraining and validating the models.

- The study produced more qualitative, rather than quantitative results. To study the effects of, for example, lithology or fluid variations, more detailed statistical analyses should be performed.

- When studying lithology effects on the RPT’s, simple siliciclastic lithologies were assumed (shale, shaly sands, sandy shales and clean sands). Even in a siliciclastic system, mineralogy can vary significantly. For example, sands can be quartz-rich (Arenite) or feldspar rich (Arkose), with very different elastic properties that must be taken into consideration. Types and amount of particular clay minerals may also be important, especially where shaly reservoirs are studied (Ødegaard and Avseth, 2004).

- The effective pressure was computed assuming a constant pressure gradient of 10 kPa/m. However, various geological factors may cause pore pressure variations that diverge from the general trend. The pore pressure is an important input for the calculation of fluid properties and for determining the effective stress on the grain contacts of the overburden-supporting rock frame (Ødegaard and Avseth, 2004).

- The acoustic properties of the drilling mud formation water and hydrocarbons in the area of investigation should also be used as input into the creation of rock physics templates (Ødegaard and Avseth, 2004).

- Other parameters, such as Silica ooze and Opal A to Opal CT transitions, volcanic tuff, sill intrusions, calcite cement, and shallow overpressure, are rarely modelled and may be potential pit-falls during the interpretation.
Finally, the fluid substitution analysis has several inherent uncertainties. These are addressed in the uncertainty analysis in Section 6.4 (Chapter 6 – ‘AVO modelling’).
In this chapter, the general applicability of the AVO technique for the study of selected reservoirs is studied with the help of forward AVO modelling. To begin with, sensitivity to some of the commonly chosen parameters for the creation of synthetic seismics is studied and discussed. AVO signature of reservoir intervals (using synthetic seismics) is then studied separately. Fluid substitution is performed on selected reservoirs in order to predict the associated change in AVO. Finally, uncertainties of the study are discussed.

6.1. Parameters of forward AVO modelling

In this study, synthetic seismic data was produced using well log data. In order to appreciate the sensitivity of forward AVO modelling to the choice of wavelet type and well log blocking method for the creation of synthetic seismics, a brief investigation was performed, using on a chosen reservoir interval in the Kobbe Formation in well 7225/3-2 (Norvarg) as an example.

6.1.1. Sensitivity to wavelet type

As previously mentioned, real seismic data was not considered in this study due to time constraints. Instead, AVO analysis was performed using synthetic seismic data. A common practice when creating synthetics seismics is to extract a statistical wavelet from actual seismic data. When this information is not available, an idealised wavelet is created, with its parameters expected to be a valid approximation of a true wavelet.

Several different wavelet types and their parameters were used to generate synthetic seismic data over a gas saturated reservoir interval (1593-1608 m MDKB – measured depth from Kelly Bushing) in the Kobbe Formation in well 7225/3-2 (Norvarg). The reservoir has an average water saturation of 51%.

The relatively large depth and small thickness of the reservoir raises concerns about whether or not it can be properly resolved in real seismic data. Resolution is defined as the ability to distinguish two features from one another. The seismic method can sometimes be strongly limited in its ability to separate features that are very close to one another. Generally, it is the seismic wavelength that controls the resolution.
Wavelength is defined by the following equation:

$$\lambda = \frac{V}{F}$$  \hspace{1cm} (6.1.1.1)

where, \(\lambda\) – wavelength, \(F\) – frequency, and \(V\) – seismic velocity.

The velocity of a rock is an intrinsic property that cannot be changed by the geophysicist. Therefore, resolution depends on the ability to increase frequency. Both vertical and horizontal resolution can be improved in this way (Amundsen and Landrø, 2013).

The Rayleigh limit of resolution is commonly used for determining the limits of separability. It states that in order to be resolved, the bed thickness must be at least one quarter of the dominant wavelength (Figure 6.1). This is also known as tuning thickness. For thinner intervals, the effect of the top and bottom reflector on the seismic signals merge and it becomes increasingly difficult to separate the interfaces.

Interference from the top and bottom reflector results in the amplitude being progressively attenuated until the limit of visibility is reached and the reflection signal becomes obscured by the background noise. The limit of visibility depends on: (i) the acoustic contrast of the layer of interest in contrast to the embedding material, (ii) the signal-to-noise ratio, and (iii) the shape of the seismic wavelet. In good conditions that limit is set to around 1/32 of the wavelength (Brown, 2004).

In addition, the earth acts as a low pass filter and tends to reduce amplitude at high frequencies more than at low frequencies. Attenuation is controlled by lithology and state of consolidation. In this particular case, the average P-wave velocity is around 3500 m/s and the reservoir thickness is 15 m. By using Equation 6.1.1.1 and assuming Rayleigh’s limit of resolution \(1/4 \lambda\), we see that, theoretically, the dominant frequency of the seismic waves should be around 58 Hz, in order to be able to separate the interval. In the marine case, conventional acquisition system is said to have a usable bandwidth between 8-80 Hz (Amundsen and Landrø, 2013).

Several types of idealised wavelets exists, which can be chosen to perform convolution with the reflectivity series. Each type of wavelet can either be zero phase, constant phase, or minimum phase, and the frequency content is specified by the user. Wavelet parameters chosen for the sensitivity analysis are given in Table 6.1.
Table 6.1: Types of wavelets and their parameters used for sensitivity analysis.

<table>
<thead>
<tr>
<th>Wavelet name</th>
<th>Ricker 1</th>
<th>Ricker 2</th>
<th>Ricker 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dominant frequency</td>
<td>45</td>
<td>60</td>
<td>90</td>
</tr>
<tr>
<td>Phase type</td>
<td>linear</td>
<td>linear</td>
<td>linear</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Wavelet name</th>
<th>Band pass 1</th>
<th>Band pass 2</th>
<th>Band pass 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low cut</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Low Pass</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>High pass</td>
<td>50</td>
<td>90</td>
<td>90</td>
</tr>
<tr>
<td>High cut</td>
<td>60</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Phase type</td>
<td>linear</td>
<td>linear</td>
<td>minimum</td>
</tr>
</tbody>
</table>

To investigate the effect of the wavelet, the sonic and density logs had to be blocked first as this helps capture significant changes in impedance. The automatic non-uniform blocking algorithm was used, which attempts to determine the maximum-likelihood for detection of large events. An average block size of 25 meters was chosen. A reflectivity series was then produced and convolved with the chosen wavelets. The parameters for sample rate (2 ms), wavelet length (150 ms) and phase rotation (0) were kept constant, while other parameters were varied. The AVO effect was then studied at the exact horizon where the reflection should have occurred, i.e. the reflection interface.

![Figure 6.2: Zero offset single trace synthetic seismics using different wavelets. The highlighted zone marks a gas saturated reservoir interval (1593-1608 MDKB, m) in well 7225/3-2 (Norvarg). BP - band pass.](image)

The effect of the different wavelets on the synthetic seismics in the 1D case is shown in Figure 6.2. A single trace, produced with each wavelet, is shown together with the P-wave reflectivity series and the neutron-density log responses. The gas saturated reservoir zone is distinguished by the negative separation of the neutron and density.
curves. The top of the reservoir is characterised by a negative reflection coefficient, due to the lower impedance of the gas saturated sandstone, compared with the overlying shale, and the bottom of the reservoir is characterised by a positive reflection coefficient of a larger magnitude.

The ‘Band pass 1’ wavelet has a relatively low resolution, while the ‘Band pass 2’ is seen to have a similar response to the ‘Ricker 2’ wavelet. ‘Band pass 3’ is a causal wavelet, which means that its maximum energy comes after the reflection event. It is therefore not ideal for the purpose of interpretation.

![Figure 6.3: Wedge model showing the effects of tuning on an idealised linear phase Ricker wavelet.](image)

In reference to the Ricker wavelets, the increasing dominant frequency has the effect making the wavelet shorter and the resolution is increased. The amplitude, however, decreases. The increased amplitude at lower frequencies results from constructive tuning effect between the side and main lobes of the wavelet responses at the top and bottom of the reservoir. With increasing resolution, the wavelets begin to interfere less and the amplitude is reduced. A schematic representation of the effect is shown in Figure 6.3. To study the effect of tuning on the wavelet, a wedge model is often employed. It helps the interpreter assess the vertical resolution, onset and maximum tuning thicknesses, travel time shift and amplitude decay below tuning thickness (Simm et al., 2014). The wedge model was not used in this study.

Next, the effect of the different wavelets on the AVO response was studied. Pre-stack angle synthetics seismic data was created using the Zoeppritz algorithm for 36 angles (0° to 35°). The AVO signature was measured at the exact reflection point and plotted in the Gradient versus Intercept crossplot (see figure Figure 6.4).

The AVO signature from all wavelets, except for ‘Band Pass 3’, plotted in the same quadrants of the Gradient versus Intercept plot. The ‘Band pass 1’ wavelet gave the lowest gradient and intercept values. The response of the remaining wavelets was similar. The ‘Ricker 2’ wavelet is chosen for use in all further analyses, due to its dominant frequency (60 Hz) which is similar to the theoretical dominant frequency required for reaching the limit of separation for the studied interval (58Hz). Wavelets with higher dominant frequencies may not be realistic to achieve in actual seismic acquisition.
6.1.2. Sensitivity to blocking method

In this section, the effect of the blocking size and type is investigated on the same gas reservoir of the Kobbe Formation, as previously (well 7225/3-2 – Norvarg).

Blocking sizes of 3, 10 and 25 m were used on the density, P- and S-wave velocity logs for both a uniform and a non-uniform blocking method. The resultant curves were
then used to create reflectivity series and an AVO Gradient versus Intercept crossplot and the results compared with the those from the non-blocked case.

Figure 6.5 illustrates the reservoir interval, represented by the negative separation between the neutron and density logs, together with reflectivity series produced by the different blocking methods. The non-uniform blocking method works much better at producing reflection boundaries at the exact top and bottom of the reservoir interval, while the uniform method tends to shift the reflectivity above or below the interfaces with significant change in impedance.

The ‘non-uniform 3 m’ blocking gives reflectivity spikes close to the top and bottom of the reservoir, which would would likely introduce unwanted interference. Both the ‘non-uniform 10 m’ and ‘non-uniform 25 m’ blocked logs produce good results, with the latter producing the best results, with no unwanted interference close to the bottom or top of the reservoir.

Synthetic seismic was also produced using all of the blocked and the non-blocked logs. Results were then plotted in the Gradient versus Intercept crossplot and compared (see figure Figure 6.6). Except for the ‘uniform 25 m’ blocking, the differences observed between the seismics from non-blocked and blocked logs are small compared to the differences observed between results from different wavelet parameters. Based on the results, the ‘non-uniform 25 m’ blocking method was chosen for use further in the AVO analysis. In the particular case that was studied, this method was able to enhance the reflectivity of the top and bottom of the reservoir better than other methods, and was able to mask unwanted closely spaced reflectivity, which could produce interference.

![Figure 6.6: AVO Gradient versus Intercept plot showing the effect of different blocking methods on the top and bottom AVO signatures of a selected reservoir interval (1593-1608 MDKB, m) in well 7225/3-2 (Norvarg), Kobbe Formation. NB – no blocking; NU – non uniform blocking; U – uniform blocking; T – top; B – bottom.](image)
6.1.3. Other parameters

Fluid effects on the AVO signature are commonly studied by performing fluid substitution using the Gassmann’s relation. It can be informative to study the effects of a mixed fluid phase, by increasing the saturation of hydrocarbons. For mixed fluid phases, velocities depend both on the saturation and spatial distribution of the phases within the rock (Figure 6.7).

![Figure 6.7: Uniform and patchy saturation effects on velocity, for varying mixtures of water and gas in a porous rock according to Gassmann theory (from Avseth, 2015).](image)

A homogeneous distribution assumes that the different wave-induced increments of pore pressure in each phase have time to diffuse and equilibrate during a seismic period. In this case, the introduction of small amounts of a strongly compressible fluid (e.g. gas) has the effect of rapidly decreasing the P-wave velocity. With increasing saturation of a compressible fluid, the density reduces more rapidly than the associated change in bulk modulus, which has the effect of slightly increasing the P-wave velocity. For a patchy saturation, wave-induced pore pressure gradients cannot equilibrate during the seismic period, causing higher velocities and impedances than when the same fluids are mixed homogeneously. This makes the rock stiffer and results in the P-wave decreasing linearly with increasing saturation of a more compressible fluid. Patchy saturation can be caused by variations in wettability, permeability or shaliness within a reservoir (Avseth, 2015).

In this study, a homogeneous saturation was assumed and used for simplicity. Employing this assumption is expected to produce strong AVO signatures at low gas saturations.

In this study, pre-stack angle synthetic seismics were created using blocked P-, S-wave and density logs and employing the Zoeppritz algorithm, which allows the derivation of the exact plane wave amplitudes of a reflected P-wave as a function of angle. Ray path is determined using the automated ray tracing method. Amplitudes are then calculated using the full Zoeppritz equation and analysed using the two term Aki-Richards approximation.
6.2. Results

In this section, the results of forward AVO modelling on selected reservoir intervals in the Kobbe, Snadd and Stø Formations are presented.

6.2.1. Kobbe Formation

In-situ AVO signatures of the 3 gas saturated reservoirs – ‘Channel A’ (1593-1608 m MDKB; average $S_w = 0.51$), ‘Channel D’ (1777-1793 m MDKB; average $S_w = 0.55$), and ‘Anomaly 2’ (1910-1928 m MDKB; average $S_w = 0.66$) in well 7225/3-2 (Norvarg) are shown in Figure 6.8.

Figure 6.8: AVO Gradient versus Intercept plot for the 3 reservoir intervals of Kobbe Formation in well 7225/3-2 (Norvarg) (upper left, lower left and lower right). Augmented Rutherford and Williams (1989) gas sand classes are indicated for reference. Amplitude versus angle of incidence plot for the top and bottom of each reservoir interval is shown in the top right. ChA – ‘Channel A’, ChD – ‘Channel D’, An2 – ‘Anomaly 2’, T – top, B – bottom. AVO signature of the reservoir top is displayed as a red square, reservoir bottom – green square. Grey points show AVO signature of the entire Kobbe Formation.

Synthetic seismics were produced for the entire Kobbe Formation. The grey data
points in Figure 6.8 show the AVO signature of the entire formation and are expected to show the background trend for brine saturated sediments.

AVO signatures of the top and bottom ‘Channel A’ and ‘Channel D’ were observed to plot well outside the background trend. The top of ‘Anomaly 2’ has a small positive intercept and a large negative gradient, and plots in quadrant IV of the AVO Gradient versus Intercept plot. The background trend is observed to deviate from the standard assumption \((V_P/V_S = 2)\) and has a \(V_P/V_S\) ratio lower than 2.

Figure 6.9: AVO Gradient versus Intercept plot for a reservoir interval ‘Channel A’ (1593-1608 m, m) in the Kobbe Formation in well 7225/3-2 (Norvarg) for various fluid scenarios. T – top reservoir, B – bottom reservoir. The numbers in the legend specify the saturation percentage of a particular fluid.

Reservoir interval ‘Channel A’ was selected for fluid substitution analysis. The effects of varying amounts of gas, oil and a fully brine saturated case were compared in the AVO Gradient versus Intercept domain by performing fluid substitution (Figure 6.9).

For the brine saturated case, the AVO response is observed to plot well within the background trend. Substituting brine with just 10% gas has a strong effect of moving both the top and bottom of the reservoir responses away from the background trend. With 10% gas the top of the reservoir shows a low negative intercept and a high gradient. Increasing the amount of gas to 50% and then to 100% has the effect of increasing the magnitude of the intercept (more negative) and slightly decreasing the gradient. In contrast, substituting for oil shows that 10% oil has little effect with the response plotting within the background trend. Increasing oil saturation to 50% and further to 100% drags the response outside the background trend, but far less than just 10% gas saturation.

6.2.2. Snadd Formation

To investigate the AVO response of the Snadd Formation sandstones, three reservoir intervals were chosen for different depth intervals (Top Snadd reservoir at 814-842 m MDKB, in well 7225/3-2 (Norvarg); intra-Snadd reservoir at 1170-1191 m MDKB, in well 7228/1-1; and bottom Snadd reservoir interval at 1361-1419 m MDKB, in
well 7226/2-1 (Ververis)). All three intervals were earlier found to be fully brine saturated. Synthetic seismics were created for the entire Snadd Formation for each well to visualize the background trend.

Responses from all three intervals were observed to plot within the background trend (Figure 6.10). The background trend in wells 7226/2-1 (Ververis) and 7228/1-1 is similar to the to the general trend, assuming a $V_P/V_S$ ratio of 2, while the trend in well 7225/3-2 (Norvarg) is found to deviate from the general trend, with a $V_P/V_S$ ratio higher than 2. The AVO signature of the top of reservoirs in wells 7226/2-1 (Ververis) and 7228/1-1 plots in quadrant II, and quadrant III for well 7225/3-2 (Norvarg). AVO signatures in all formations appear to plot within the background trend.

Reservoir interval in well 7226/2-1 (Ververis) (1361-1419 m MDKB) was selected for fluid substitution analysis (Figure 6.11). Introducing 10% gas into the reservoir has the
CHAPTER 6. AVO MODELLING

Effect substantially increasing the intercept and reducing the gradient. Increasing the volume of gas has an effect of linearly increasing both the intercept and gradient. At 100% gas saturation, the top reservoir has a significantly larger intercept, but a similar gradient to that of the brine saturated case. Substituting the in-situ fluid with oil has the effect of linearly increasing the intercept and reducing the gradient, with increasing oil saturation. Just 10% of gas is observed to produce a higher AVO signature than a 100% oil saturated case.

6.2.3. Stø Formation

Thin, high impedance layers have been observed within the sandstones of the Stø Formation. These intervals are characterized by significantly higher P-, S-wave and density values than surrounding rocks and produce a very strong response in the synthetic seismics, obscuring the AVO effects and complicating the study (Figure 6.12). Well 7324/10-1 was chosen for the study Stø Formation. The high impedance layer obscured the bottom reservoir AVO response, therefore only the top response was studied. The Stø sands in well 7324/10-1 were earlier found to be fully water saturated, therefore their AVO signature was expected to be within the background trend for the in-situ case. Synthetic seismics were created for the interval from the top of the overlying Fuglen to the base of the underlying Fruholmen Formations. No hydrocarbons are described within the interval and its AVO signature is assumed to show the background trend.

The general background trend shows a $V_P/V_S$ ratio higher than 2 (Figure 6.13). The top of the reservoir sand has a negative intercept and a positive gradient, and plots within the background trend in quadrant II in the AVO Gradient versus Intercept plot. Introducing 10% gas into the reservoir has the effect of significantly increasing the intercept and decreasing the gradient. Additional gas saturation has the effect of slightly increasing both the intercept and gradient. When oil is introduced into
the reservoir, the AVO intercept increases (becomes more negative) and the gradient decreases linearly, and much less pronounced than in the gas substitution case. Only at approximately 50% oil saturation does the AVO signature begin to deviate from the background trend. Even 100% oil saturation does not produce such a strong effect as just 10% gas saturation.

Figure 6.13: AVO Gradient versus Intercept plot for a reservoir interval (569-577 MDKB, m) in the Stø Formation in well 7324/10-1 for various fluid scenarios. T – top reservoir, B – bottom reservoir. The numbers in the legend specify the saturation percentage of a particular fluid. Augmented Rutherford and Williams (1989) gas sand classes are indicated for reference.
6.3. Discussion

6.3.1. Kobbe Formation

Gas saturated reservoir intervals ‘Channel A’ (average $S_w = 0.51$) and ‘Channel D’ (average $S_w = 0.55$) in well 7225/3-2 (Norvarg) show a clear Class III AVO signature, according to the classification scheme by Rutherford and Williams (1989) (Figure 6.8). Class III response is commonly associated with unconsolidated sands and may be thought of as unexpected for these reservoir intervals, considering the rather deep burial they were subjected to (see Section 3.3.3 in the ‘Methodology and theoretical background’ chapter for estimations of uplift and erosion).

However, as discussed in the previous chapter, a low degree of quartz cementation (up to 5%) was found in the sandstones of the Kobbe Formation by means of thin section analysis by Line (2015). The study was done in the Fingerdjupet Sub-basin, Loppa High and Nordkapp Basin and linked the preservation of porosity to effective and extensive chlorite coating. In this study, quartz cement between 1-5% was inferred from the rock physics models (although the models were not correlated against thin section analysis).

The AVO signatures of these reservoirs suggests that the degree of diagenesis in reservoirs ‘Channel A’ and ‘Channel D’ is low, which agrees with the observations of the rock physics diagnostics.

In contrast, gas saturated reservoir ‘Anomaly 2’ ($S_w = 0.66$) AVO signature plots in quadrant IV, close to the background trend. Despite the presence of gas in this reservoir, the fluid effect appears to be small. This could be related to consolidation. If the reservoir is more consolidated, compared to the other two, the fluid effect may be reduced. Also, gas saturation percentage is lower in this reservoir. It has been shown in rock physics diagnostics that the fluid effect is reduced for the reservoirs of the Kobbe formation. It may be that lower gas saturation in this reservoir leads to a weaker AVO signature. Fluid substitution should be performed on this reservoir in order to further study its fluid sensitivity on AVO.

6.3.2. Snadd Formation

Some reservoir intervals in the Snadd Formation show a Class IV signature, while others are observed to have a Class III signature (Figure 6.11). Class IV anomalies are associated with shallow unconsolidated sands or soft sands below hard cap rocks (such as hard shale, siltstone or carbonate) (Chopra and Castagna, 2014).

Similarly to the Kobbe Formation, the sandstones of the Snadd Formation were found in different studies to have significant chlorite coating, which acts to preserve porosity and hinder cementation (Line, 2015; Net et al., 2015). Up to 5% cement was inferred from the rock physics diagnostics in this study (although correlation of the models with thin section data was not performed). It can be argued that this porosity preserving mechanism has kept the reservoir intervals in the Snadd Formation relatively unaffected by diagenesis despite the deep burial, leading to this type of AVO signature.
Some of the Snadd reservoirs show a Class III signature and may be more cemented. Variations in cementation have been linked to the presence of chlorite coating, which is more prevalent in certain depositional environments of the Snadd Formation, but not others (Net et al., 2015).

6.3.3. Stø Formation

AVO study of the Stø Formation within the study area is hindered by relatively thin, high-impedance layers, which tend to produce a strong seismic response and obscure the AVO signatures (Figure 6.12). Where they can be studied, reservoir intervals of the Stø Formation can be classified as Class IV sands. This is a soft sand response (Figure 6.13).

Up to 3% cement in the Stø Formation sandstones was inferred from the rock physics diagnostics in this study (although no correlation of the models with thin section data was performed). These sandstones are therefore likely to be less consolidated than the sandstones of the Kobbe and Snadd formations.

The study by Zhang (2014) has found that the Stø Formation displayed signatures of all 4 sand classes in the Hammerfest Basin and Ringvassøy-Loppa Fault Complex (to the south-west of the present study area). Variations in burial depth and cementation can be expected to produce significantly different AVO signatures for the Stø, depending on the area of study.
6.4. Uncertainties

Some of the uncertainties involved in the AVO forward modelling stem from the fluid substitution analysis:

- Properties of pore filling fluids were not available in this study. Therefore, constant approximate fluid properties were selected for the fluid substitution, which may not be a good approximation of the in-situ situation.

- Core porosity was not available for this study. Calibration of log derived porosity with core porosity is highly desirable and may significantly alter the results of fluid substitution in some cases, such as for low porosity and complex lithologies (Smith et al., 2003).

- For the purpose of simplicity, the bulk modulus of the mineral matrix for the fluid substitution was approximated from the estimated shale volume log, assuming 2 mineral end members of quartz and clay. The presence of other types of minerals and varying elastic properties of different clay minerals can significantly affect the results.

Many simplifications were employed during the process of synthetic seismic creation:

- A stationary source pulse (wavelet not time-varying) was assumed. This is not the case in actual seismics, as the source pulse is modified as it passed through the earth. For the purpose of AVO reconnaissance, however, this can be a good approximation.

- A linear phase Ricker wavelet was used to produce the synthetic seismic dataset. While this can be a valid approximation, this type of wavelet can never be expected in actual seismic data. This is largely due to seismic commonly having a flat topped as opposed to a peaked amplitude spectrum (as is the case for the Ricker wavelet). When possible, it is preferable to use a wavelet extracted from actual nearby seismic data.

- No noise contribution was considered. Various types of noise are present in actual seismic data, defined as the seismic energy other than primary reflections. Both coherent and random noise is unwanted and can significantly affect an AVO study. Random noise, for example, has a systematic effect on intercept and gradient, where, for a given horizon, slightly different intercept and gradient fits will be made at each gather (Simm et al., 2014). It is possible to add random noise into the synthetic seismic data, to better appreciate the actual seismic response.

- The generated synthetic seismic data is multiple free. Multiples are defined as internal reflections within a layer, caused by large reflection coefficients. They can cause significant interference with the primary signal and data interpreters must be careful not to distort the AVO signature when removing multiples. Due to the large differences in impedance between the air, water and seabed layers, multiples have a constant presence in marine seismic data and would be expected in seismic data from the study area.
• Transmission loss, geometric spreading and frequency-dependent absorption are ignored in synthetic generation.
CHAPTER 7

Summary and Conclusions

High technical success rate of exploration within the Norwegian Barents Sea fuels interest for future exploration and development of the region, with approximately half of Norway’s undiscovered hydrocarbon resources being projected by the Norwegian Petroleum Directorate to be present here. However, complex geological development, involving significant Cenozoic uplift and complicated depositional environments, dominance of gas finds, with a relatively large distance from potential markets, environmental concerns as well as other complications make the Barents Sea a challenging area for hydrocarbon exploration and development.

The study area stretches across the southern part of the Bjarmeland platform, from the Hoop Fault Complex in the western part, to the Norvarg Dome in the central part, and towards the western margin of the Nordkapp Basin in the eastern part. Triassic (Kobbe and Snadd) and Jurassic (Sto) Formations were selected for the primary focus. The main objective was to characterize reservoir quality within the mentioned formations. Geophysical well data from 8 exploration wells (7 wildcat and 1 appraisal) was available for this study. Three of the wells are classified as hydrocarbon discoveries (7324/8-1 – Wisting oil discovery; 7225/3-1 – Norvarg gas discovery; and 7226/2-1 – Ververis gas discovery). Of the remaining wells, 7225/3-2 is a Norvarg discovery appraisal well; 7324/7-1, 7324/10-1, 7228/2-1S are described as having hydrocarbon shows; and well 7228/1-1 classified as a dry well.

To achieve the study objectives, geophysical well log data was used to perform petrophysical analysis, rock physics diagnostics and forward AVO modelling. Results and discussion were supplemented by published literature. Varying degrees of uncertainty are associated with each method applied in this study. The major uncertainties are discussed at the end of ‘Petrophysical analysis’, ‘Rock Physics Diagnostics’ and ‘AVO Modelling’ chapters.

Petrophysical analysis was performed to estimate lithology, shale volume, porosity, saturation and net-to-gross values. These parameters were later used in rock physics diagnostics to study lithology, porosity and fluid effects on the seismic properties. Rock physics effective medium models were employed for estimations of compaction and consolidation. Unfortunately, these models were not correlated with thin sections. Instead, results were discussed with reference to thin section studies by other authors in neighbouring areas in southwestern Barents Sea. Finally, well log data (P-wave, S-wave and density logs) was used to generate synthetic seismics and study the AVO
signatures in forward AVO modelling. Fluid substitution was performed for the purpose of estimating fluid sensitivity.

Due to time restriction, seismic data, sedimentological analysis and petrographical study of cores and cuttings are not considered in this study. This is also considered to be the major limitation. Inclusion of the mentioned data is expected to significantly improve the analysis and interpretation of the data. Perhaps most importantly, verification of the various geophysical models used in this study with actual sedimentological, core and thin section analyses could greatly improve the understanding of the link between geological parameters and associated observed geophysical response.

The following conclusions are drawn from this study:

- Reservoir intervals of the Kobbe Formation were found to be relatively thin – up to $\sim 18$ meters in thickness. Relatively low effective porosities (up to $16\%$) and high amounts of shale (up to $37\%$) further complicate reservoir quality. However, the sandstones of the Kobbe Formation were found to have some degree of gas saturation in most of the intervals within the study area, which may fuel interest for future exploration.

- The Snadd Formation was found to have many reservoir intervals, with intra-Snadd reservoirs of up to $\sim 58$ meters in thickness. Relatively high effective porosities (up to $24\%$) but also rather high shale volumes (up to $30\%$) were estimated by petrophysical analysis. The intra-Snadd reservoir sands, which were interpreted by other studies to represent channel sandstone bodies, deposited in an otherwise mudstone dominated coastal plain environment (see, for example, Klausen et al., 2015), were found to have the best reservoir qualities. Unfortunately, most of the reservoir intervals were fully brine saturated, with only a few having hydrocarbon shows. Despite this, the high thickness and extent of the Snadd Formation, coupled with good reservoir qualities and associated shales with good petroleum generation potential (see, for example, Lerch et al., 2016), make it an interesting target for future exploration.

- The Stø Formation was found to have reservoir intervals with the best reservoir qualities, compared with the other studied formations, with low shale volume and relatively high effective porosities (up to $26\%$). High reservoir qualities are attributed to the prograding coastal depositional environment, which was responsible for the deposition of clean sands (see, for example, Smelror et al., 2009). Relatively shallow depth of the Stø reservoirs, despite significant exhumation of the study area, means that the formation has not experienced such high degree of diagenesis as, for example, the Kobbe Formation (see, for example, Baig et al. (2016) for estimations of uplift within the study area). Two reservoir intervals within the study area are hydrocarbon saturated (oil in well 7324/8-1, Wisting discovery; and gas in well 7225/3-1, Norvarg discovery). Despite having good reservoir qualities and significant hydrocarbon accumulations, the Stø Formation is relatively thin (8-61 m) and discontinuous within the study area. Nevertheless, where it extends, the Stø Formation can be expected to have a high potential for hydrocarbon discoveries.
• Compaction and cementation analysis showed that Kobbe Formation reservoir intervals were mostly cemented, with potential quartz cement volumes of 2-4% for the shallowest reservoirs, up to approximately 12% for the deepest. Snadd Formation reservoirs showed potential quartz cementation of between 0-5%, while the cleanest channel sandstone intervals showing around 2% cement. Sandstones of the Stø Formation showed the lowest degree of diagenesis. Up to 5% cement was estimated, with most of the data points showing between 0-2% potential quartz cement. Unfortunately, these results were not calibrated against thin section studies, due to the time constraint. Correlation should be done in order to constrain the rock physics models.

• $V_p/V_S$ versus AI and Lambda-Mu-Rho crossplots were used to study lithology, porosity and fluid effects on the seismic properties. A good discrimination between reservoir and capping rocks was observed for the reservoirs of Kobbe Formation. Porosity values, however, were significantly underestimated, which can be related to the effects of cementation and/or variation in mineralogy. In-situ gas saturation was observed to drag the data points toward the gas trend line, but not as strongly as predicted by the models. The effects of cementation could be responsible for decreasing the fluid effects, while relatively high volumes of clay may have the effect of dragging data towards the shale cluster.

• The Snadd Formation sandstones were observed to have a good agreement with the modelled sandstone trend line in the $V_p/V_S$ versus AI plot. Good discrimination between shales and sands was observed. The surrounding shales are thought to be much more sandy, compared to those in the Kobbe Formation. This is seen in the $V_p/V_S$ versus AI plot with reservoir-surrounding shales often plotting close to the sandstone trend. Fluid substitution showed the expected effects of dragging the data towards the gas saturated trend line, but with a lesser than predicted amount. Relatively high shale volume within the sandstones could be responsible for dampening the fluid effect, by dragging data toward the shale cluster.

• Good agreement between the modelled clean sandstone trend line and sandstones of the Stø Formation was observed. Good discrimination between the sands and overlying shales of the Fuglen Formation was observed. Oil saturated reservoir sands in well 7324/8-1 (Wisting) showed a weaker fluid effect than that predicted by fluid substitution analysis. Some of this effect may be attributed to the elastic properties of the saturating oil. If these elastic properties are closer to that of brine, this could explain the lower than expected fluid effect.

• Gas saturated sands in the Kobbe Formation display a strong Class III signature, with top and bottom reservoir responses plotting well outside the background trend. However, a deeply buried gas-saturated reservoir interval was observed to plot near the background trend, possibly displaying a weak Class I signature. Therefore, the effects of cementation may obscure the effects of AVO, depending on the burial depth and associated degree of cementation in some of the Kobbe Formation reservoirs.
• Brine saturated reservoir intervals of the Snadd Formation display Class IV and Class III signatures, when fluid substitution is performed. Class IV signature (commonly associated with soft, unconsolidated sands) in some of the reservoir intervals of Snadd, can be related to certain depositional environments, as suggested by other studies (see, for example, Net et al., 2015), where the development of chlorite coating was dominant and is responsible for preserving high porosities.

• Similarly to the soft sand of the Snadd Formation, the sands of Stø Formation showed a Class IV AVO signature, which is associated with soft sands. However, thin, high impedance layers within the sandstones of the Stø Formation were found to obscure the AVO effects in most of the studied wells. These layers may be related to different lithology types or highly cemented layers. The study by Walderhaug and Bjørkum (2003), for example, has found that the degree of quartz cementation in the Stø Formation can have significant variations, even within a short interval.
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Figure A.1: $V_p$-depth trend for well 7324/7-1S, colour coded by gamma ray.
Figure A.2: $V_p$-depth trend for well 7324/8-1, colour coded by gamma ray.
Figure A.3: $V_p$-depth trend for well 7324/10-1, colour coded by gamma ray.
Figure A.4: $V_p$-depth trend for well 7225/3-1, colour coded by gamma ray.
Figure A.5: $V_p$-depth trend for well 7225/3-2, colour coded by gamma ray.
Figure A.6: $V_p$-depth trend for well 7226/2-1, colour coded by gamma ray.
Figure A.7: $V_p$-depth trend for well 7228/1-1, colour coded by gamma ray.
Figure A.8: $V_p$-depth trend for well 7228/2-1S, colour coded by gamma ray.
Composite well logs

Figure B.1: Composite well logs for the Stø Formation in well 7324/7-1. Depth is given in meters, measured from Kelly Bushing.
**Figure B.2:** Composite well logs for the Stø Formation in well 7324/8-1. Depth is given in meters, measured from Kelly Bushing.

**Figure B.3:** Composite well logs for the Stø Formation in well 7324/10-1. Depth is given in meters, measured from Kelly Bushing.
APPENDIX B. COMPOSITE WELL LOGS

Figure B.4: Composite well logs for the Stø Formation in well 7225/3-1. Depth is given in meters, measured from Kelly Bushing.

Figure B.5: Composite well logs for the Stø Formation in well 7225/3-2. Depth is given in meters, measured from Kelly Bushing.
Figure B.6: Composite well logs for the Stø Formation in well 7228/2-1S. Depth is given in meters, measured from Kelly Bushing.

Figure B.7: Composite well logs for the Snadd Formation in well 7324/7-1S. Depth is given in meters, measured from Kelly Bushing.
Figure B.8: Composite well logs for the Snadd Formation in well 7324/8-1. Depth is given in meters, measured from Kelly Bushing.

Figure B.9: Composite well logs for the Snadd Formation in well 7324/10-1. Depth is given in meters, measured from Kelly Bushing.
Figure B.10: Composite well logs for the Snadd Formation in well 7225/3-1. Depth is given in meters, measured from Kelly Bushing.

Figure B.11: Composite well logs for the Snadd Formation in well 7225/3-2. Depth is given in meters, measured from Kelly Bushing.
Figure B.12: Composite well logs for the Snadd Formation in well 7226/2-1. Depth is given in meters, measured from Kelly Bushing.

Figure B.13: Composite well logs for the Snadd Formation in well 7228/1-1. Depth is given in meters, measured from Kelly Bushing.
**Figure B.14:** Composite well logs for the Snadd Formation in well 7228/2-1S. Depth is given in meters, measured from Kelly Bushing.
Figure B.15: Composite well logs for the Kobbe Formation in well 7324/7-1S. Depth is given in meters, measured from Kelly Bushing.

Figure B.16: Composite well logs for the Kobbe Formation in well 7324/10-1. Depth is given in meters, measured from Kelly Bushing.
**Figure B.17:** Composite well logs for the Kobbe Formation in well 7225/3-1. Depth is given in meters, measured from Kelly Bushing.

**Figure B.18:** Composite well logs for the Kobbe Formation in well 7225/3-2. Depth is given in meters, measured from Kelly Bushing.
**Figure B.19:** Composite well logs for the Kobbe Formation in well 7226/2-1. Depth is given in meters, measured from Kelly Bushing.

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**Figure B.20:** Composite well logs for the Kobbe Formation in well 7228/1-1. Depth is given in meters, measured from Kelly Bushing.

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Figure B.21: Composite well logs for the Kobbe Formation in well 7228/2-1S. Depth is given in meters, measured from Kelly Bushing.