AES/TG/14-22  Reservoir Characterisation of the Jurassic Posidonia Shale Formation and the Triassic Deposits of the Main Buntsandstein Subgroup by Seismic Inversion Methods, Block Q16, West Netherlands Basin

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Reservoir Characterisation of the Jurassic Posidonia Shale Formation and the Triassic Deposits of the Main Buntsandstein Subgroup by Seismic Inversion Methods, Block Q16, West Netherlands Basin

By

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Abstract

The objective of this study was to perform a reservoir characterisation of the Posidonia Shale Formation and the Bunter reservoir, through seismic inversion techniques, in order to obtain several rock properties and analyse how their variations are related to changes in depth, lithology and fluid content. Posidonia Shale is interesting as an unconventional hydrocarbon prospect because it is a bituminous type II kerogen source rock with approximately 5-7% of TOC content. The Bunter reservoir is interesting as it consists of uniform massive stacked fluvial and eolian gas-bearing sandstones of approximately 200 meters in thickness. The study area (256 km²) is located in the Q16 block in the West Netherlands Basin. Structurally it is characterised by half grabens. Posidonia Shale Formation and Bunter reservoir are compartmentalised. Their depths range between 2300 and 2800 meters and between 2500 and 3500 meters respectively.

A model-based seismic inversion method and a pre-stack simultaneous seismic inversion method were carried out in order to estimate several rock properties. In addition to the pre and post stack PSTM seismic data, ten wells are located within the study area. As these ten wells did not have recorded shear wave velocities these were estimated by a Xu-White model (Xu and White, 1995 and 1996) and were calibrated at the Posidonia and Bunter intervals with nearby wells that had recorded shear wave velocities. Key horizons were interpreted and were used along with the well logs to generate the low frequency models of acoustic impedance, shear impedance and bulk density. These models were filtered in order to keep the low frequencies, below 10Hz which are missing from the available seismic data.

The resultant volumes of acoustic impedance, shear impedance and bulk density obtained from the inversions honoured the well-log data. From these volumes other rock properties were derived namely shear modulus, bulk modulus, Young’s modulus, Vp/Vs ratio, Poisson’s ratio, lambda*rho and mu*rho. At Posidonia Shale, the acoustic and shear impedances and rock properties decrease compared to the bounded shales, which made it easily to follow this Formation laterally. Moreover, at Posidonia Shale interval, the Young’s modulus and Poisson’s ratio were used to estimate a Brittleness index. The southern area of the mapped Posidonia Shale presented the higher brittleness index, which implies that this area has a more plastic behaviour than ductile and thus is likely to be easier to fracture. Furthermore, the west of the mapped Posidonia Shale was selected as a sweet spot area for performing hydraulic fracturing since this zone has a larger continuous extension, it is thicker and it is more brittle. In the case of the Bunter reservoir, the shear modulus and Mu*Rho increased in cleaner sandstones and hence they are considered reliable lithology discriminators, while Poisson’s ratio and Vp/Vs ratio decrease in the presence of gas and, in consequences, they are considered reliable fluid discriminators. The top and base of Bunter reservoir were easier to recognise laterally on these rock property volume than on the original seismic volume.
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1. Introduction

The objective of this study is to characterise the Jurassic Posidonia Shale Formation, a source rock, and the Triassic sandstone deposits of the Main Buntsandstein Subgroup at Block Q16 located in the West Netherlands Basin (Figure 1.1). The characterisations of these deposits were carried out through seismic inversion techniques. The main purpose of this characterisation is to analyse the rock properties obtained from seismic inversion in order to understand their variations related to depth, lithology, porosity and fluid content in both intervals, and calibrate these with known well information.

![Figure 1.1 Location of the study area](modified_from_van_Adrichem_Boogaert_and_Kouwe_1993.png)

The Posidonia Shale Formation is a Toarcian bituminous claystone deposited under anoxic conditions during a period of high sea level. It is a type II kerogen source rock with an average TOC content of approximately 5-7% and an average thickness of 30 meters. The Posidonia Shale is considered the main source rock for hydrocarbon generation in the western
zone of the West Netherlands Basin (van Bergen, 2013). According to these characteristics, Posidonia Shale Formation can be classified as an unconventional reservoir. These types of reservoirs present a very low permeability, typically less than 1mD. Structural or stratigraphic traps are not needed for producible hydrocarbon accumulations; hence they may be laterally extensive. Hydraulic fracturing, also known as fracking, is a method employed for producing hydrocarbons from these unconventional deposits. The rock is fractured in order to created pathways where gas or oil can flow (Speight, 2013 and Sinclair et.al, 2010).

Oil and gas shales can be heterogeneous, in the sense of mineral composition such as clay minerals, quartz, carbonates, pyrites and others. Areas of shales with higher content of brittle minerals like quartz and carbonates are easier to fracture than zones with higher percentage of clay, where the behaviour of the rock could be more plastic or ductile (Verma et., 2012). Therefore, sweet spots with large amount of brittle minerals could be identified in order to optimize the hydrocarbon recovery. A rock that is considered brittle is more susceptible to be fractured. In other words, the shale has an elastic behaviour or less deformation when it is submitted to stress. The brittleness index is a parameter that allows the quantification of the rock brittleness. This can be estimated through the rock properties of Poisson’s ratio and Young’s modulus that can be derived using P-wave velocities, S-wave velocities and bulk densities (Perez et al., 2013).

The Main Buntsandstein Subgroup consists of Early Triassic arkosic sandstones and clayey siltstones of approximately 200 meters thickness deposited under fluvial and eolian sedimentary environments. It is sub-divided into the Volpriehausen, Detfurth and Hardegsen Formations. These units have porosities from less than 6 to almost 20% and gas saturations range from 30 to 80% (Geluk et al., 1996). Sandstones from the Volpriehausen Formation can be tightly cemented by dolomite, reducing the porosity and therefore the quality of the reservoir (Purvis and Okkerman, 1996). In this study the Main Buntsandstein Subgroup is named the Bunter reservoir.

Seismic inversion techniques were employed in order to characterise these two reservoirs, Posidonia Shale Formation and Bunter reservoir, at Q16-block. Seismic data is used as one of the input in the performing of seismic inversion with the final goal of estimate rock properties. A 3D seismic dataset of 256 km$^2$ was used in this study. The seismic data was available as pre-stack migrated stack and as CDP NMO-corrected gathers, with an offset between 300 and 3300 meters. In this area, the Posidonia Shale Formation is located at depths (TVDSS) between 2300 and 2800 meters (between 1700 and 2400 ms in TWT) and the Bunter reservoir is found at depths between 2500 and 3500 meters (between 1800 and 2800 ms in TWT).

The other main input for performing seismic inversion comprised well-logs. Eleven wells are situated within the area: P18-A-02, P18-02, Q16-03, Q16-04, Q16-05, Q16-FA-101-S1, Q16-08, MSG-01, MSG-02, MSG-03 and MSV-01-S2. Most of these wells are highly deviated. Well-log information was available in the public database [www.nlog.nl](http://www.nlog.nl). Gamma ray, P-wave transit times, bulk density, neutron porosity and depth resistivity logs were collected, organised, processed and interpreted. On the other hand, S-wave transit times were estimated through a Xu-White Model. This model is an iterative process that makes
used of the logs: P-wave velocity, total effective porosity, bulk density and shale volume that were also previously calculated and assumed aspects ratios of sandstones and shales. Dry rock properties are estimated by Kuster-Toksöz method, and then those are filled with fluids through Gassman equations in order to calculate P-wave velocity. This modeled P-wave velocity is compared with the logged values. If they match, then a shear wave is calculated. If they do not match, the aspects ratios for shales and sandstones are changed. Initially the aspects ratios are 0.12 for sandstones and 0.03 for shales.

Two types of seismic inversion were carried out, a model-based seismic inversion and a pre-stack simultaneous seismic inversion, both using the software Hampson & Russell. The model-based inversion method is an iterative process where a known wavelet is convolved with an initial modeled reflectivity that was calculated from a low frequency acoustic impedance model. The synthetic seismic traces obtained from this convolution are compared to the original seismic traces, in this case the 3D seismic data. In the beginning, the differences between the synthetic and the original seismic traces are large because the input comprised a sparse low frequency model. Through optimization methods the model is updated and the convolution process is repeated until the differences between the seismic traces are small enough. As a consequence, the final output would be the last acoustic impedance model used to calculate the reflectivity. In this study, the model-based inversion was hard constraint, which means that there is a maximum impedance change. This change is a percentage of the well-log average acoustic impedances. The pre-stack simultaneous inversion has the same principle. The difference between this inversion and the model-based one is that the latter use post-stack seismic data where the final output is an acoustic impedance model, while the former one employs the gathers data in order to generate acoustic impedance and bulk density models. Moreover, Pre-stack simultaneous inversion takes into consideration the offsets or angles of reflections and also use low frequency models of shear impedance and bulk density. In this study, the final outputs are P-impedance, S-impedance and bulk density volumes.

The low frequency models were built using well-logs, RMS velocities and interpreted horizons. During the construction of these models, the high frequency content that the well-logs add to the model were eliminated with a high-cut frequency filter. Consequently, these models contain frequencies between 0 and 10 Hz, which is the range of frequencies missing from the seismic data. Several horizons were interpreted after performing well-seismic ties using checkshots for converting the wells from depth to time and a Butterworth wavelet for convolution. The well-tops found in the public database were used to interpret six horizons: Top Ommelanden Formation, Top Texel Formation, Base of Cretaceous Unconformity, Top Posidonia Shale Formation and two near horizons to the Bunter reservoir. For purpose of the seismic inversion, these horizons guide the lateral interpolation of the model between the wells. They are the structural and stratigraphic constraints to the model, and they are especially important because this area is structurally complex, with presence of horsts and grabens below the base of Cretaceous Unconformity.
An additional input to the seismic inversion process was the wavelet. A full wavelet of 200ms of length was extracted using the wells and the seismic data near those wells after an improved manual well-seismic tie was performed.

Other rock properties were calculated from the obtained acoustic impedance (Zp), elastic impedance (Zs) and bulk density (ρb) volumes. These properties were: P-wave velocity (Vp), S-wave velocity (Vs), Vp/Vs ratio, Poisson’s ratio (ν), shear modulus or second Lamé parameter (μ), Bulk modulus or incompressibility (K), Young’s modulus (E), first Lamé parameter (λ), λ*ρ and μ*ρ. Similar estimations were done from well-log data. Several crossplots were created in other to analyse the behaviour of these rock properties at Posidonia Shale Formation and Bunter reservoir intervals. These crossplots were coloured with properties such as volume of shale (Vsh), water saturation (Sw) and effective porosity (οeff) in order to characterise not only the rock but also its fluid content. In the case of the Posidonia Shale Formation, a brittleness index was estimated using the well-logs and the volumes of Poisson’s ratio and Young’s modulus. In the case of the Bunter reservoir, an effective porosity volume was calculated by a trend found in the crossplot of effective porosity versus acoustic impedance.

The bulk modulus is the ratio of volumetric stress to volumetric strain. On the other hand, the shear modulus is the ratio of shear stress to shear strain. Furthermore, the rock bulk modulus might be mainly dependent on the pore fluid bulk modulus. Conversely, the rock shear modulus is hardly unaffected by fluids. Therefore, when a liquid is replaced by a compressible free gas in the pore space, the rock P-wave velocity will decrease considerably, meanwhile the rock S-wave velocity will be slightly increased because of the decreasing bulk rock density. As a result, the Vp/Vs ratio is considered to be a good indicator of free gas in the pore space.

One of the principal goals of this study is that the Zp, Zs and ρb volumes obtained from the seismic inversion methods, as wells as the volumes of rock properties estimated, honour the well-log data, specially at Posidonia Shale Formation and Bunter reservoir intervals. In that way, the interpretation is more reliable of the vertical and lateral variations of these rock properties. Composite lines that pass through the wells of several rocks properties were analysed at reservoir intervals. Moreover, maps were generated of these properties in order to study lateral changes.

This project is part of a large study, with main objective to estimate rock properties from core samples through mineralogy composition and nanoindentation techniques in order to eventually upscale these properties to well-logs and, in that way, make a calibration.
2. Regional Geology

Several authors such as van Adrichem Boogaert and Kouwe (1993), Rondeel et al. (1996), de Jager (2007) and Kombrik et al. (2012) have described the regional geology of the Western Europe area. The following chapter summarises the work of these authors regarding the evolution of main tectonic and sedimentary settings occurred in the Dutch subsurface. Figure 2.1 illustrates the principal structural features of this area from Silesian to Cenozoic times.

The tectonic history of the western Europe begins with the Pangea Supercontinent, which was formed during the convergent of Laurentia, Baltica and Gondwana continental plates in Paleozoic times. The collision of Laurentia and Baltica cratons formed the Laurussian continent during Ordovician and Silurian periods. Moreover, Caledonian fold belt was developed during this collision. Simultaneously, the amalgamation of Baltica and Gondwana continents caused the development of the North German-Polish Caledonides. These two areas, the Caledonian basement in the North and the Gondwana-derived Avalonia with the London-Brabant Massif to the South, formed the basement of the Netherlands. In the northern offshore, the Caledonian basement consists of altered biotite monzo-granite overlain by non-metamorphosed Middle-Late Devonian Old Red Sandstones, which are interpreted as fluvio-lacustrine sediments. On the other hand, marine conditions existed in the southern part of the Netherlands, allowing the deposition of the Banjaard Group. In general, sedimentation prevailed during the Devonian, while London-Brabant Massif and Elbow Spit remained as highs. Furthermore, Middle Devonian to Early Carboniferous graben blocks were found in the Dutch onshore. These blocks are associated with NNW-SSE trend faults, which might be related to the NNW-SSE oriented seaway developed across the eastern Netherlands into the Proto-Dutch Central Graben (van Adrichem Boogaert and Kouwe, 1993 and de Jager, 2007).

Laurassia and Gondwana continents started to converge during the Middle to Late Devonian ages. This collision caused the formation of The Himalayan-type Variscan orogeny in the Early Carboniferous. The development of these Variscan Mountains to the South originated that the area of the Netherlands was land-locked. Farne Group was deposited in the North where deltaic sedimentation prevailed, while carbonate platforms with some sediment-starved basins developed in the South where clastic sedimentation was limited, these sediments are known as the Carboniferous Limestone Group. In the Late Carboniferous, these carbonate platforms were buried by siliciclastic sediments and the deep basins were filled by the Limburg Group, which is composed of fluvio-deltaic sediments and large amount of coals, showing a regressive mega-trend. During Silesian epoch, the Variscan belt started prograding northwards. This slightly affected the North European Basin, which was a foreland basin with a humid equatorial climate by Carboniferous times. Caledonian age fault zones were rejuvenated by this Variscan deformation. At the end of the Carboniferous, the northern Variscan forelands suffered compressional deformation, while Ems Low and Proto Central Graben experienced rifting process. Subsequently, Saalian deformation phase took place. Thermal uplift and magmatism caused wrench faulting, which generated widespread and deep erosion, leaving locally deep truncation of the Silesian deposits. At the end of the
Variscan orogenesis, sedimentation stopped and a major hiatus developed separating Carboniferous deposits from Permian ones. Younger feature like Sole Pit, Broad Fourteens, West and Central Netherlands Basins, Ems Low and the Central Graben were controlled by Silesian-Permian faults, or even older ones, in the beginning (van Adrichem Boogaert and Kouwe, 1993, de Jager, 2007 and Kombrik et al., 2012).

Figure 2.1 Main tectonic features of the Dutch subsurface. Structural elements of: a) Silesian. b) Early Permian. c) Late Permian. d) Triassic to Liassic. e) Late Jurassic to Early Cretaceous. f) Cenozoic. (From van Adrichem Boogaert and Kouwe, 1993).
After the tectonic-magmatic event started to decay, regional subsidence began during Permian. In other words, a calmer period occurred from Permian to Middle Jurassic, where sediments were deposited, having the Saalian unconformity as the base and the Mid Kimmerian unconformity as the top. Clastic sediments of Upper Rotliegend Group were deposited in an arid climate within a large East-West orientated basin known as southern Permian Basin. Upper Rotliegend Group consists of fluvial and eolian sandstones, which prograded from South to North into a playa basin characterised by fine-grained deposition with intercalation of halites. During the Late Permian, still under an arid climate, a depression was generated due to the large subsidence rates. This depression was suddenly filled with saline-sea water. Several evaporation cycles left the Zechstein sequence deposited. This Group consists of five evaporite cycles, Z1 to Z5, where the dominant lithology in Z1 is anhydrite and became more halite dominant in the upper cycles. Moreover, it is composed of a thick succession of cyclic marine evaporites in the northern part, while in the offshore Southern part it is found as basin fringe facies (van Adrichem Boogaert and Kouwe, 1993, de Jager, 2007 and Kombrik et al., 2012).

The break-up of the Pangea supercontinent by rifting process began in the Mesozoic. The area of the Netherlands moved from arid climate zone to sub-tropical latitudes in the northern hemisphere. Continuous thermal subsidence dominated during Triassic and Early Jurassic times. This subsidence caused the development of a brackish to saline lacustrine environment where the Lower Buntsandstein Formation was deposited. This sequence is characterised by fine-grained clastics, which are overlain by coarser-grained fluviatile and eolian clastics of the Main Buntsandstein unit. Lower Buntsandstein Formation and Main Buntsandstein sequence form the Lower Germanic Trias Group. This is separated from the Upper Germanic Trias Group by the Basal Solling Unconformity as a result of an uplifting phase during the Middle Triassic. At that time, a connection of the South with the Tethys Ocean allowed the influence of a marine environment, depositing in that way the Röt Evaporites with an alternation of fluvio-lacustrine sediments. Subsequently, the sedimentation gradually changed to fully marine marls and limestones of the Muschelkalk Formation. A more humid climate prevailed and fine-grained siliciclastic sediments came from the North constituting the deposition, together with intercalated lagoonal and evaporitic sediments, of the Keuper Formation. The Triassic-Jurassic boundary separates the shallow marine deltaic sediments from the fully argillaceous marine Altena Group. A calm period can be described during the Late Triassic and Early Jurassic times, where slow regional subsidence prevailed. Deposition of the organic-rich shales of Posidonia Shale Formation occurred in the Early Jurassic (van Adrichem Boogaert and Kouwe, 1993, de Jager, 2007 and Kombrik et al., 2012).

Uplifting of the Central North Dome occurred in the Middle Jurassic under influence of the Mid Kimmerian tectonic movements. Important erosion of northern Jurassic and Triassic sediments took place in the Central North Sea due to this thermo-magmatic uplift. Igneous activity began, heat flow increased and extensional faulting accelerated. As consequence, rift structures were completely developed, such as the Central Graben, Broad Fourteens Basin and West Netherlands Basin during Late Jurassic – Early Cretaceous times. High sedimentation rates and significant facies changes in the basin areas characterised the deposition during rifting.
times. Dutch Central Graben and Broad Fourteens rift basins were filled with fluvio-lacustrine sediments of Schieland and Scruff Groups from the Late Jurassic to the Earliest Cretaceous. By this time, this process culminated with the formation of the Late Kimmerian Unconformity during a regional low-stand of sea level. Subsequently, sea-level started to increase again accompanied with thermal subsidence. This caused that the open marine basin was filled with the transgressional sequence of the Rijnland Group, which consists of mainly fine-grained clastics with coastal sandstones (van Adrichem Boogaert and Kouwe, 1993, de Jager, 2007 and Kombrik et al., 2012).

Although the regional extension in the Netherlands was with an East-West orientation, only the Dutch Central Graben presents this configuration. Other basins have a NW-SE direction, which follow older structural trends. Thus, their main faults are dextrally reactivated older faults with transtensional displacement (de Jager, 2007).

Regional thermal subsidence and increment of the sea level occurred during the Late Cretaceous. As consequence, previously stable highs such as London-Brabant Massif, Rhenish Massif, Ringkøbing-Fyn and Mid North Sea began to subside rapidly. At the same time, younger sediments started to accumulate due to the creation of accommodation space until the entire area was below submerged again. Sandstones of the Vlieland Formation were deposited. Those consist of complex barrier systems and shallow marine sequences strongly bioturbated. This formation was overlain by marine fine-grained sediments of the Vlieland Shale Formation. Decreasing clastic sediment supply and still rising sea level generate the accommodation pace for marine carbonates to be deposited. Locally this sequence reaches 1500m of thickness. Firstly, Holland Formation was deposited. This is composed of an alternation of marls and claystones. This formation was covered by pure limestones of the Chalk Group (van Adrichem Boogaert and Kouwe, 1993, de Jager, 2007 and Kombrik et al., 2012).

Eurasia and Africa-Arabia tectonic plates started to converge during the Late Cretaceous. In consequence, Tethys system began to close and the Alpine orogenic system developed. The stress produced by the formation of this Alpine orogen generated the inversion of Mesozoic extensional basins. Several inversion phases or pulses affected the area eroding rift sequences, such as Upper Cretaceous Chalk and Lower Tertiary clastics, due to the uplifting. Furthermore, inversion phases are divided in Subhercynian, Laramide, Pyrenean and Savian. During the Laramide inversion phase in the Paleocene age, sediment supply increased changing the carbonate environment for a siliciclastic one, allowing the deposition of the North Sea Super Group, which is characterised by an alternation of distal marine sediments with shallow marine sands. West Netherlands Basin, Central Netherlands Basin, Broad Fourteens Basin and Dutch Central Graben suffered important erosion down to Jurassic deposits. Sub-hercynian, Laramide and Pyrenean unconformities were created during these inversion phases. Overall, subsidence dominated in the North Sea rift system during Cenozoic, resulting in a thick sequence of sediments deposited in the North Sea Basin, bounded by the Laramide or Pyrenean unconformity at their base. During the Miocene and Pliocene, the remaining accommodation space was filled by the sediments of the Eridanos delta system, which prograded westwards from Scandinavia and Denmark (van Adrichem Boogaert and Kouwe, 1993, de Jager, 2007 and Kombrik et al., 2012).
Figures 2.2 and 2.3 show a simplified stratigraphic diagram and a litostratigraphic column respectively of the Netherlands subsurface.

Figure 2.2 Simplified stratigraphic chart of the Netherlands. (Kombrink et al., 2012).
Q16 Block is located offshore in the West Netherlands Basin that has an orientation NW-SE (Figures 2.1 and 2.4). It is surrounded by the Broad Fourteens Basin and IJmuiden Platform to the North, Oosterhout Platform and Roer Valley Graben to the South, Zeeland High and Indefatigable Platform to the West and Peel-Maasbommel Complex to the East (Kombrink et al., 2012). During the Triassic, subsidence of this basin predominated due to sediment loading, while extensional faulting became important in the Late Jurassic. Half-grabens are the characteristic structural style, in which coastal clastic sediments were accumulated. Furthermore, Zechstein salt was not deposited. Rift faults were re-activated as reverse ones during inversion phases in Late Cretaceous times (van Adrichem Boogaert and Kouwe, 1993). According to Rondeel et al. (1996), when Zechstein salt is absent or breached, Carboniferous gas could migrate to higher reservoirs like continental Triassic sandstones or fluvio-marine Upper Jurassic and Lower Cretaceous reservoirs. Figure 2.5 illustrates an interpreted seismic cross-section that passes through the West Netherlands Basin, showing
the half-graben structures and the absent of salt tectonics. Most of the gas was generated during the Jurassic and Cretaceous, but the likely amount of gas formed was larger than the size of present-day traps. During Late Cretaceous – Early Tertiary, the inversion phase stopped the generation and hence the charge of gas. Structures evolved or modified during this stage are often found to be water-bearing, most likely as they postdate the main hydrocarbon generation and migration phase. Many Upper Jurassic and Lower Cretaceous clastic reservoirs have been charged by the Lower Jurassic marine Posidonia Shale source rock, which has been preserved in the West Netherlands and Broad Fourteens Basins, and in the Central Graben (further north offshore).

Figure 2.4 Locations of the West Netherlands Basin and Q16-Block. A-A’ is a seismic cross-section illustrated in Figure 2.5. (Modified from Kombrink et al., 2012).
Figure 2.5 Interpreted seismic cross-section that passes through the West Netherlands Basin. Figure 2.4 illustrates the location of this line. (Modified from ten Veen et al., 2012).
3. **Reservoir Geology**

**Triassic (Lower and Upper Germanic Trias Group)**

Two principal lithological groups can be distinguished within the Triassic deposits: the Lower Germanic Trias Group and the Upper Germanic Trias Group. Subdivisions in these Groups are shown in Figure 3.1. The former one is composed of lacustrine claystones and fluvial sandstones, and the latter one consists of lacustrine to marine claystones, marine carbonates and evaporites, with minor intercalations of fluvio-lacustrine sandstones. Layer cake geometry characterizes these Triassic deposits on regional and reservoir scales. This can be seen in Figure 3.2. Two extension phases caused the main variation within the Triassic: the Hardegsen phase influencing the distribution of the Main Buntsandstein and the Early Kimmerian phase causing the uplifting and erosion of Muschelkalk and Keuper Formations (Geluk et al., 1996).

![Figure 3.1 Stratigraphic diagram of the Triassic in the Netherlands and neighbouring countries. (From Geluk, 2007).](image-url)
At the end of Permian period, the deposition of marine evaporites finished due to sea-level dropping in Northern and Southern basins. A continental environment prevailed with influx of coarse clastic sediments from southern source areas during the Early Triassic. Also, a complex rift system was created. This passed through the Variscan fold belt and Permian basins. After the occurrence of uniform subsidence, large domal swells were developed in the main parts of the Netherlands onshore during the Scythian. During the Late Permian-Scythian, Lower Buntsandstein Formation was deposited in a lacustrine sedimentary environment. Cyclic alternation of lacustrine fine-grained sandstones and clayey siltstones composed the lower unit of this group. A large fluvial feeder system governed the deposition of the Buntsandstein by transporting clastics from the Vosges in NE France northwestward through the Roer Valley Graben and West Netherlands Basin into the Off Holland Low. Up to 200 meters of massive sandstones and conglomerates were deposited in the Roer Valley Graben and Pell Block thanks to this feeder system. These sediments were eventually covered by claystone beds. In the West Netherlands Basin, Lower Buntsandstein Formation is gradually thinning and onlapping towards the Brabant Massif. Consequently, strong fluvial influence allowed the deposition of the Main Buntsandstein Subgroup, which consists of
cyclic alternation of (sub-) arkosic sandstones and clayey siltstones. Volpriehausen, Detfurth and Hardeggen Formations composed this unit. Even though these deposits are predominantly of fluvial origin, eolian sediments are also found in the northern quadrants P and Q. Extensional tectonics of Hardeggen phase controlled thickness and facies distribution of these Formations. Swells were uplifted at the end of the Scythian, causing the erosion of the sediments previously deposited and thus creating the Base Solling Unconformity. Subsequently, those swells were covered by sandstones and claystones of the Solling Formation during the latest Scythian period. The source of sediments of the lower part of the Upper Germanic Trias Group came from the southern areas, meanwhile the upper part were derived from the northeast. Because of the Netherlands was located far away from these northern source areas, the latter deposits are commonly fine-grained (van Adrichem Boogaert and Kouwe, 1993 and Geluk et al., 1996). Figure 3.3 illustrates that the base of the Lower Germanic Trias Group is between approximately 3000 and 4000 meters of depth and its thicknesses is between 150 to 200 meters at Q16 block.

Figure 3.3 a) Depth map (in km) of the base of the Lower Germanic Trias Group. b) Isopath map (in meters) of the Lower Buntsandstein Formation. Q16 block area enclosed by the dotted square. (Modified from Geluk, 2007).
**Lower Buntsandstein Formation**

The Lower Buntsandstein Formation was deposited during the latest Permian - early Seythian period. It consists of cyclical alternations of anhydritic claystones, siltstones and sandstones or calcareous oolite beds. This oolite layers are found mainly in the upper part of the Formation. In general, the thickness of this unit is very continuous over large areas and, as was mentioned before, it can reach 150 meters in the Western Netherlands Basin. Claystones of the Zechstein Group underlying the base of the Lower Buntsandstein Formation, while the Volpriehausen Formation is found as the upper boundary. Features such as: red and green mottled intervals, anhydrite and carbonate nodules and desiccation cracks allowed the interpretation of an ephemeral lake sedimentary environment characterised by periodic flooding and drying. The oolitic limestone layers are indicative that a shallow lacustrine environment with low siliciclastic sediment supply occurred. The Lower Buntsandstein Formation is divided into two sub-units: the Main Claystone Member and the Rogenstein Member. The former one is composed of red-brown to green silty, anhydritic claystones with some sandstone beds and oolite layers. The latter member is differentiated from the first one by the regular intercalation of up to one meter thick oolite beds, which are used as regional correlation markers. These oolite layers are replaced by sandstone beds at the southern part of the country (van Adrichem Boogaert and Kouwe, 1993).

**Volpriehausen Formation**

In general, the Volpriehausen Formation is widely distributed and well-preserved on the Netherlands Swell and the Cleaver Bank High below the Base Solling Unconformity. It is bounded by the Lower Buntsandstein Formation in the lower part, forming a subtle unconformity, and the Detfurth Formation in the upper part, or Solling Formation in the swells, which might be difficult to identify. The Volpriehausen Formation presents two units: Lower and Upper Volpriehausen Sandstone Members. The first one is composed of clean pink to grey fine-grained sub-arkosic sandstones, which contain strongly cemented reworked material in its lower part. Moreover, the lowermost interval part consists of less than 50% quartz with a high percentage of dolomite and calcite cement. On average, this Member possess up to 10% of porosity in the West Netherlands Basin and up to 15% in the Ems Low. It can reach 75 meters of thickness in the Off Holland Low and 15 meters in the Ems Low due to limited accommodation space. Furthermore, these sandstones show a cylindrical or blocky shape on the Gamma Ray well-logs, which is a characteristic of massive bedded sandstones that are lithologically uniform, typical of tidal channels, barrier bars and fluvial channel sands in the delta plain. This aggrading trend also means that the sandstones have a uniform porosity. This Member has a lateral equivalent towards the Netherland Swell called Volpriehausen Clay-Siltstone, which consists of small-scale fining-upwards cycles of reddish to greenish fine-grained sandstone, siltstone and claystone. The second one consists of light-brown carbonate-cemented sandstones with several thin greenish claystone rhythmic
Intercalations. Thicknesses of 150 meters of this succession can be found in the Roer Valley and less than 50 meters in the Netherlands swells. The uppermost sandy sediments of this member are restricted to the northern area of the Off Holland Low and the Roer Valley Graben. While the Lower Volprieheusen Sandstone Member is considered one of the best reservoirs, the Upper Volprieheusen Sandstone Member is dismissed due to its cementation. Dolomite, anhydrite and ankerite cements are found in its pore spaces (van Adrichem Boogaert and Kouwe, 1993 and Geluk et al., 1996). Figure 3.4 shows depths of approximate between 3500 and 4000 meters of the top Lower Volprieheusen Sandstone Member. Thicknesses of this Member range between 40 and 60 meters at Q16 block (Kombrink et al., 2012).

Figure 3.4 a) Depth of top Lower Volprieheusen Sandstone Member. b) Thickness of Lower Volprieheusen Member. Q16 block area enclosed by the dotted square (Modified from Kombrink et al., 2012).
**Detfurth Formation**

The Detfurth Formation is bounded by the overlain Hardegsen Formation and underlain by the Volpriehausen Formation. The base of this sandstone forms a subtle unconformity. Due to the truncation at the Basal Solling Unconformity, the distribution of the Detfurth Formation is restricted to the Triassic lows such as the Roer Valley Graben, the West Netherlands Basin, the Off Holland Low, the Ems Low and the Central Graben. Two sub-units compose the Detfurth Formation: Lower and Upper Detfurth Sandstone Members. The latter one gradually evolves into the Detfurth Claystone member to the North. This unit consists of red-brown anhydritic claystones. Lower Detfurth Sandstones Member is characterised by low gamma ray and low acoustic velocity readings. Within the Main Buntsandstein, the Lower Detfurth Sandstone Member is considered one of the best reservoir units, which consists of light-coloured massive arkosic sandstones containing up to 60% of quartz grains whilst being quartz cemented. In the West Netherlands Basin, its porosities vary between 15% and 20%. Due to subsidence during deposition, this sandstone can locally have a thickness of more than 50 meters in the Ems Low; meanwhile thicknesses of 10 meters are observed in the Roer Valley Graben and Off Holland Low. The Upper Detfurth Sandstone has two claystone intervals, which can be distinguished by high gamma ray values. In the West Netherlands Basin, this unit can have thicknesses between 20 and 30 meters. This succession can be very useful when regional correlations need to be done. The equivalent unit Detfurth Claystone Member reaches 50 meters in the Ems Low (van Adrichem Boogaert and Kouwe, 1993 and Geluk et al., 1996).

**Hardegsen Formation**

Stratigraphically, the Hardegsen Formation, of Scythian age, is the uppermost unit of the Main Buntsandstein. It is bounded by the Detfurth Formation below and the Solling Formation above, separated by the Basal Solling or Spathian Unconformity. This Formation consists of rapid alternation of off-white to pink sandstones and claystones. Arkosic sandstones without claystone intercalations or massive sandstones can be found in the southern part of the Netherlands, onshore and offshore. Transition between Solling Formation and Hardegsen formation is characterised by a sudden decrease of compressional velocity. Perhaps this could be related to the fact that their altered feldspars exhibit leaching leading to secondary porosities of up to 20% in the West Netherlands Basin. Due to the Basal Solling Unconformity, this unit is located only in the centres of the West Netherlands Basin, the Roer Valley Graben, the Off Holland Low, the Ems Low and the Central Graben. While its development is very limited in the eastern parts, it has a wider distribution in the southern areas. Its thickness varies a lot due to the erosion below this Unconformity (van Adrichem Boogaert and Kouwe, 1993 and Geluk et al., 1996).
Solling Formation

The Solling Formation was deposited during the latest Scythian age. This unit unconformably overlies the Main Buntsandstein Subgroup or the Lower Buntsandstein Formation. A well-cemented basal sandstone characterised this unconformity. This can be seen in more pronounced wireline log values compared to those shown by the underlain Main Buntsandstein Subgroup. Röt Evaporite Member can be found above the Solling Formation. Regarding its lithology and sedimentary environment, Solling Formation was deposited during a major transgression after the tectonic movements of the Hardegsen phase stopped. It consists of basal grey sandstones interpreted as braided-river deposits overlying by red lacustrine claystones. It can reach over 100 meters of thickness in the Ems Low and less than 25 meters within the Roer Valley Graben, West Netherlands Basin and Off Holland Low. Solling Formation is divided in two units: Basal Solling Sandstone Member and Solling Claystone Member. The former one is composed of light-coloured massive or cross-bedded dolomite-cemented sandstones, which are characterised by high resistivity well-log readings. The latter one consists of red, green and locally grey claystones that normally show high gamma ray values in the basal part. Sandstones become more prominent in the western offshore (van Adrichem Boogaert and Kouwe, 1993 and Geluk et al., 1996).

Lower and Middle Jurassic (Altena Group)

The Altena Group is composed of uppermost Triassic, and Lower and Middle Jurassic deposits, which consists of a thick succession of marine claystones, siltstones, marls and a few sandstones. Regarding its sedimentary settings, there was a change in the depositional environment at the end of the Triassic. During Permian and Triassic, evaporite sedimentation of red-beds occurred product of arid climate. At Rhaetian age, the development of an open-marine system allowed the deposition of claystones and marls in thick layers. A thinner, more calcareous sequence with occasional iron oolites is found in some elevated structural features. A few intercalated sandstones and sandy and oolitic carbonates indicate low-stand sea level periods and/or hinterland uplift. Hardgrounds originate in periods of non-deposition and/or reworking. The Altena Group shows first a transgressive and then a regressive trend.

The Sleen Formation is the basal unit of this Group. It is a thin, marine, fossiliferous, shaley claystone of Rhaetian age deposited during a very rapidly transgression event. This unit is more or less continuously present in the basin centre and it lies locally unconformable on underling Triassic sediments at the basin margins. Widespread deposition of an argillaceous limestone bed, which constitutes the base of the Aalburg Formation, was the result of the open-marine conditions developed from the Hettangian age until the earliest Toarcian in western Europe. Aalburg Formation is composed of a monotonous succession of dark, marly clays and silts with intercalated thin limestone beds. An anoxic environment at the bottom of the basin prevailed during Early Toarcian due to a high sea level period and restricted basin circulation. Given these conditions, Lower Jurassic bituminous shale
claystone called Posidonia Shale Formation was deposited. This unit is considered one of the most important oil source rocks in southern North Sea region and the Netherlands. Overlain Posidonia Shale is found the Werkendam Formation, which consists of silty claystones with one prominent sandy marlstone intercalation called Middle Werkendam Member. Well-oxygenated open-marine conditions developed in Late Toarcian characterised the sedimentary environment in which the Werkendam succession was deposited. After the first pulse of the Late Kimmerian uplift during Late Oxfordian-Early Kimmeridgian, marine environment retreated from the Netherlands (van Adrichem Boogaert and Kouwe, 1993). In Figure 3.5 can be seen a chronostratigraphic chart of the Altena Group of the Central Netherlands Basin with their different depositional facies (Wong, 2007).

According to Kombrink (2012), the base of the Altena Group can be found approximately at depths between 2500 and 3500 meters, and the thicknesses of this Group can approximate vary between 600 to 1800 meters at Q16 block (Figure 3.6) (Wong, 2007).

**Figure 3.5** Stratigraphic chart of larger Jurassic basins in the Netherlands. (From Wong, 2007).
Posidonia Shale Formation

As mentioned above, the Aalburg Formation is found conformably below the Posidonia Shale. The Aalburg Formation is composed of non-bituminous marine claystones. On the other hand, the Posidonia Shale Formation received its name thanks to the dominant fossil type Posidonia (lamellibranch genus). This rock is a dark-grey to brownish-black fissile claystone unit of Toarcian age, which gives high gamma ray and high resistivity reading on wire-line logs. The presence of the Posidonia Shale is restricted to basin centres of the Roer Valley Graben, the West Netherlands Basin, the Central Netherlands Basin, the Broad Fourteens Basin, the Central Graben and isolated locations in the Lower Saxony Basin. On seismic this unit can be observed as a very distinctive reflector in the Netherlands area, which can be observed in the example of the Figure 3.7. It is suggested that the deposition of the Posidonia Shale Formation occurred during a high sea level period and restricted basin-floor circulation based on the wide distribution of the unit, which goes from United Kingdom to Germany. Bituminous composition and lacking of benthic elements imply a pelagic
depositional environment with anoxic conditions. The Werkendam Formation is more or less conformably located above Posidonia Shale. It is composed of predominantly non-bituminous marine silty claystones and siltstones (van Adrichem Boogaert and Kouwe, 1993). Kombrink (2012) built a map showing the base of the Posidonia Shale Formation at approximate depths between 2000 and 3000 meters (Figure 3.8).

![Figure 3.7 Seismic line across the Pijnacker Field. Posidonia Shale reflector (dark blue) is characterised by strong amplitudes and low frequency content (Modified from de Jager et al., 1996).](image)

According to de Jager et al. (1996), Posidonia Shale Formation is a 30 meters thick marine, kerogenous type II source rock.
Figure 3.8 Depth of the base of the Posidonia Shale Formation. Q16 block area enclosed by the dotted square (Modified from Kombrink et al., 2012).
4. Seismic Inversion Theory and Methods

Inversion Theory

According to Menke (1984), inversion theory can be defined as the use of mathematical techniques in order to obtain meaningful information of the physical world from observations.

A distinction is made between forward and inverse problems. The forward problem consists of generating theoretical data from a previous model, which is called the forward model. An example of a forward problem is the generation of synthetic seismograms. In this case, the model is the Earth, which is built through elastic properties such as the compressional wave velocity, shear wave velocity and bulk density at different depths in the subsurface. Thus, the elastic properties are considered the model parameters and synthetic seismograms can be created employing a reflectivity algorithm (Sen, M. K., 2006).

On the other hand, the inverse problem tries to derive Earth model parameters from recorded observations. Direct inversion algorithms are highly unstable, and therefore these model parameters are estimated by iterative methods that match the observed data with the synthetic one. Synthetic data is obtained solving the forward problem, so a large number of Earth models are tested. Figure 4.1 illustrates a diagram of the forward and inverse problems (Sen, M. K., 2006).

Figure 4.1 Diagram displaying forward and inverse problems. Forward modeling obtains data from model parameters, while inversion estimates model parameters from observations (Modified from Sen, M.K., 2006).
Optimization techniques are used to match the observed data with synthetic ones. A mathematical function named cost function, misfit function, error function or objective function measures the differences between the observed and synthetic data. The data fit is optimal when the value of the objective function is a global minimum. The use of an iterative forward modeling in order to estimate the model parameters characterizes the model-based inversion process, where optimization is a very important step. Figure 4.2 shows a flowchart of the model-based inversion algorithm. Synthetic data is created for an assumed model and then compared with observed data. If the match is acceptable, the model is admitted as the solution. If it is not, the model is changed, and the synthetics are recalculated and compared again with the observations. This iterative forward modeling process is repeated until an acceptable matching is found between the observed and synthetic data. Thus, inversion is seen as an optimization process, where the final Earth model is that one that best explains the observations (Sen, M. K., 2006).

**Figure 4.2 Model-based inversion flowchart. Iterative forward modeling is used to estimate model parameters (Modified from Sen, M.K., 2006).**
Non-unique solutions are one of the drawbacks of inversion algorithms. A number of models can match the observed data with the same certainty. This is because the measured data is often noisy, the forward modeling is inexact and there may not be sufficient data. Therefore, the goal of the inversion is not only to find the best-fit model, but also to estimate its uncertainty (Figure 4.3) (Sen, M. K., 2006).

Figure 4.3 Estimation of model parameters and their uncertainties due to inaccuracies in measured data and inadequate forward modeling (Modified from Sen, M.K., 2006).

A lineal optimization method can be used in order to establish a relationship between the data and the model (Sen, M. K., 2006):

\[ d_{syn} = g(m) \]  
\[ \|e\|_2 = [(d_{obs} - g(m)^T)(d_{obs} - g(m))]^{1/2} \]

Where:
- \( d_{syn} \) = synthetic data vector.
- \( g \) = forward modeling operator.
- \( m \) = model vector.
- \( d_{obs} \) = observed data vector.
- \( e \) = error vector (objective function).
The inversion problem now consists of determining the model that minimises the misfit between the observed and synthetic data. Generally, the forward modeling operator $g$ is a nonlinear operator. Therefore, the error function can present multiple minima of varying levels. A well-defined minimum can only be obtained when $g$ is or can be approximated to a linear operator. In consequence, inverse problems can be classified according to the relationship between the data and the model and the behaviour of the cost function (Sen, M. K., 2006):

- **Linear inverse problems:** The relationship between the data and model is nonlinear. The forward modeling operator $g$ is nonlinear but can be approximated by a linear operator or a matrix $G$:

$$d_{syn} = Gm \quad (3)$$

Where the solution is:

$$m = G^{-1}d_{obs} \quad (4)$$

If $G^{-1}$ exists. Approximation of the solution is given by:

$$m_{est} \approx G^\theta d_{obs} \quad (5)$$

Where:

$G^\theta =$ generalize inverse.

$m_{est} =$ estimated model vector.

- **Weakly nonlinear inverse problems:** A reference model $m_0$, which is assumed to be very close to a given model $m$, is linear perturbed to data $d$:

$$d = g(m) \approx g(m_0) + \frac{\partial g}{\partial m}(m - m_0) + \cdots = d_0 + G_0 \Delta m \quad \rightarrow \quad \Delta d = G_0 \Delta m \quad (6)$$

Where:

$G_0 =$ matrix with partial derivatives of the data with respect to model parameters.

$\Delta d =$ data residual.

$\Delta m =$ model perturbation.

The model perturbation or solution can be obtained employing techniques for solving linear inverse problems.
- **Quasilinear inverse problems:** The error function is linearized:

\[
e(m + \Delta m) \approx e(m) + \Delta m^T \nabla e(m) \quad (7)
\]

Where \( \nabla e(m) \) includes the partial derivatives of error with respect to model parameters.

- **Nonlinear inverse problem:** No approximations are done. The forward modeling and error function are considered nonlinear.

The inversion solution of equation (3) can be written as:

\[
m = G^{-1}d_{obs} \quad (8)
\]

Where

\( G^{-1} \) = inverse operator of \( G \) (forward modeling operator).

Several issues need to be taken into consideration during the search for solutions:

- Existence of the inverse operator \( G^{-1} \).
- Uniqueness solution where \( G \) is an injective function and only one model explains the observed data.
- Stability in the model refers to how small errors in the observed data propagate into the model. A stable solution does not change due to small error in the measured data. Instability might lead to nonuniqueness solutions.
- Robustness is related to the grade of insensitivity that the model present with respect to small number of large errors in the measured data.

Regularization techniques can be applied in order to restore an ill-posed inverse problem, which do not have uniqueness and stability, to a well-posed inverse problem.
Two methods can be described in order to solve the linear inverse problems (Sen, M. K., 2006):

- **Method of Least Squares:** Find the minimum of the error function:

\[
E(m) = e^T e = (d_{\text{obs}} - Gm)^T (d_{\text{obs}} - Gm) \quad (9)
\]

When \( \frac{\partial E(m)}{\partial m} = 0 \).

In order for this system of linear equations \( Gm = d \) to have one unique solution, the number of equation and model parameters must be the same. This is known as an even-determined problem. If the number of parameters is larger than the data, then the problem is underdetermined. Geophysical inversions have this problem if continuous Earth model parameters are attempted to be estimated from a finite set of measurements. This can be solved by discretizing or reducing the number of model parameters in order to reduce the problem to an even-determined, or even better, to an overdetermined case. Therefore, an Earth model can be divided into a group of discrete layers instead of having the model parameters as continuous functions. On the other hand, an overdetermined problem, where there is more data than model parameters, can be solved by least squares methods.

- **Maximum Likelihood Methods:** Taking into consideration the uncertainties in the observed data, these methods try to find optimum values of the model parameters, which are those that maximize the probability of the measure data. In the case of geophysical data, the uncertainty in the measurement can be caused by random noise and also by the influence that closer data points have between each other. For a linear inverse problem, the probability can be written:

\[
p(d) \propto \exp \left[ -\frac{1}{2} (d - Gm)^T C_d^{-1} (d_{\text{obs}} - Gm) \right] \quad (10)
\]

Where \( C_d \) is the data covariance matrix and \( d \) the mean data. The maximum probability is obtained when the argument of the exponential is minimum. Thus, the error function to be minimised is:

\[
E(m) = (d_{\text{obs}} - Gm)^T W_d^{-1} (d_{\text{obs}} - Gm) \quad (11)
\]

Where \( W_d \) is a weighting matrix.
In order to transform an ill-posed inverse problem in a well-posed inverse problem avoiding nonuniqueness issues, the solution needs to be constrained. As was mentioned above, the Earth can be modeled by small number of discrete layers, which also can be seen as coarse grid points. This constraint is based on prior information or assumptions. For example, one constraint could be the restriction of the model parameters to only positive values. This will be the case of the seismic wave velocity and density parameters that always consist of positives values, therefore the resulting inversion may be constraint to positives values. Another constraint will be the use of a prior model. This means that, besides to minimise the objective function in order to improve the match between the measured and synthetic data, there is also a restriction where the model cannot deviate significantly from the prior model \( m_p \). Having this in mind, the error function could be rewritten as:

\[
E(m) = (d_{obs} - Gm)^T(d_{obs} - Gm) + \varepsilon (m - m_p)^T(m - m_p)
\]

Where \( \varepsilon \) is the regularization weight. The importance of the model and the data error is determined by this factor.

Local and global optimization methods exist in order to solve nonlinear inverse problems. The former methods search for a local minimum in the vicinity of a starting solution employing the first or second derivative of the objective function, while the latter methods look for the global minimum. In seismic inversion, local optimization methods such as steepest-descent algorithm and conjugate-gradient algorithm are used. Regarding global optimization methods, simulated annealing and genetic algorithm are commonly employed (Sen, M. K., 2006).

**Seismic Inversion Methods**

Post-stack seismic inversion methods:

- **Bandlimited inversion (recursive inversion):** This type of inversion does not take into consideration the effects of the seismic wavelet and therefore assumes that the seismic trace represents an approximation to the Earth’s reflectivity. As a result, acoustic impedances are calculated directly through the integration of the seismic traces. First, the seismic trace is converted to a reflectivity trace by deconvolution, and then the reflectivity is transformed to an impedance trace. The low frequency components missing in the input band-limited seismic data are adding to the acoustic impedance results by a smoothed Zp prior model. Nevertheless, the disregarding of the wavelet makes the final acoustic impedance model smooth like the seismic traces. Impedance from reflectivity formula can be written as (Veeken, 2006 and Hampson and Russell’s Manual, 2013):
Coloured Inversion: This method is based on the derivation of an inversion operator that matches the amplitude spectrum of the seismic to that of the acoustic impedance. The seismic trace is transformed, in frequency domain, into acoustic impedance by this operator. It is a simple and fast method that does not need a good prior model. One of the disadvantage is that the seismic data input is assumed zero phase, which is may not be the case. Another disadvantage is that the resulting relative acoustic impedances need to be calibrated (Veeken, 2006 and Hampson and Russell’s Manual, 2013).

Sparse-spike inversion: Is a broad band inversion where a group of sparse reflection coefficients are estimated from the seismic data. Initially, the reflectivity consists of large and small spikes. The large ones are located to match the seismic trace and then newer spikes are added until the fit is accurately enough. Then, the inversion of the reflectivity coefficients creates the acoustic impedances. This method generates events to match the seismic data; therefore the final model does not have thin layers often created by the model-based inversion methods. Moreover, sparse-spike inversion is less dependent on the prior model than the model-based one and it is a good approach when there is not considerable knowledge about the geology of the area. The low frequencies are added by the prior model. Two sparse-spike inversion algorithms can be described (Hampson and Russell, 1991, Veeken, 2006 and Hampson and Russell’s Manual, 2013):

- **Linear programming sparse-spike inversion:** A linear programming technique based on frequency domain constraints is used to estimate the reflectivity. As a result, this reflectivity will have the frequency content of the seismic and then it will be integrated taken into consideration the restrictions of the initial model. Limiting to a minimum number of spikes, this sparse reflectivity generates the best fitting between the synthetic trace and the real one. The calculation of the acoustic impedance is based on this sparse reflectivity and the assumption that the wavelet is known.

- **Maximum likelihood sparse-spike inversion:** A single-most-likely-addition algorithm is employed in order to positioning the optimum spikes in the reflectivity series. In other words, a sparse reflectivity sequence is generated by adding reflection coefficients one by one until an optimal result is achieved. The amplitude of the new spike is compared with the average amplitude of other spikes added so far. The algorithm stops adding spikes when this amplitude is smaller than the specified fraction of the average. Subsequently, the broadband reflectivity is changed gradually until an accurate match is obtained between the synthetic and real seismic trace. Again the calculation of the acoustic impedance is based on this sparse reflectivity and the assumption that the wavelet is known.

\[ Z_{p_{i+1}} = Z_{p_i} \left[ \frac{1 + r_{p_i}}{1 - r_{p_i}} \right] \] (13)
- **Model-based inversion**: Is a generalized linear inversion algorithm that consists of the perturbation of an initial low frequency acoustic impedance model until the resulting synthetic seismic traces best matches the observed seismic data. Figure 4.4 shows a diagram about the estimation of an acoustic impedance model by using a model-based seismic inversion method. A reflectivity model is calculated from an initial low frequency acoustic impedance model, by convolving with a known wavelet. The prior model is based on well-logs, interpreted seismic horizons and/or seismic velocities. It is a smooth model, with low frequency content that the seismic data generally does not possess. The low frequency content is coming from the well-logs. A wavelet can be extracted from seismic data or derived from a well-to-seismic match. The reflectivity model is convolved with the wavelet in order to obtain a synthetic trace. Subsequently, the synthetic trace is compared with the original seismic trace. The differences are measured and the objective function value is evaluated. If the error is small enough, then the acoustic impedance model introduced is the final solution. If the error is considered large, then an optimization method is used in order to update the prior acoustic impedance model and then start with the convolution process again. Therefore, this is an iterative process (Hampson and Russell, 1991, Veeken and Hampson and Russell’s Manual, 2013).

![Figure 4.4 Model-based seismic inversion diagram (Modified from Sen, M.K., 2006).](image-url)
Mathematically speaking, the goal is to minimise this function:

\[ J = \text{weight}_1 (S - W * r) + \text{weight}_2 (M - H * r) \] (14)

Where:

- \( S \) = Seismic trace.
- \( W \) = Wavelet.
- \( r \) = Final reflectivity.
- \( M \) = Initial low frequency acoustic impedance model.
- \( H \) = Integration operator which convolves with final reflectivity to produce final impedance.
- \(*\) = Convolution.

If the \((S - W * r)\) is minimised, then the solution will be modeling the original seismic data. On the other hand, minimising \((M - H * r)\) will generate a solution that models the initial impedance model employing the specified block size. This is balanced by the values assigned to the weights, where \(\text{weight}_1 + \text{weight}_2 = 1\). Model-based inversion can be stochastic or constraint. In the stochastic version, the solution can deviate from the initial model setting the values for both weights, which is considered a soft constraint. Meanwhile, in the constraint inversion, \(\text{weight}_2\) is zero and the final impedances are restricted to largest and smallest values (maximum impedance change), which is a percentage of the average impedance of the log, so it is considered a hard constraint due to the fact that the final model cannot go beyond these values. It is important that the process be constraint in order to prevent the algorithm be influenced by error or small amounts of noise in the data (Hampson and Russell’s Manual, 2013).

Model Based Inversion method provided by Hampson and Russell software consists in an algorithm that generates pseudo-velocity logs by dividing the zone into blocks or layers. The block size is usually larger than the sample rate of input data, so these modeled pseudo-velocity logs have lower temporal resolution compared to velocity and density logs from well information. A reflectivity estimated from this initial low frequency blocked model is convolved with the assumed known wavelet in order to build a synthetic trace as was mentioned above. The amplitude and thickness of blocks or layers are modified in order to improve the matching between the synthetic seismic trace and the real one. Thus, it is an iterative process where the synthetic trace is changing. The number of blocks remains the same, what it is adjusted is the size. A coarse velocity model is created from a large blocking interval trend, and resolution is increased as the blocking interval becomes smaller. It is very important to take into consideration the initial blocking interval because an unstable condition
may occur if this interval is made too small compared to the main lobe of the seismic wavelet. Smaller block size (large number of blocks) increases the resolution and the synthetic trace will match the real trace better, but this might be artificial when the detail is dependent on the initial guess and not on the real rock (Hampson and Russell’s Manual, 2013).

Pre-stack seismic inversion methods:

- **Simultaneous Pre-stack Seismic Inversion Method**

Simultaneous pre-stack inversion estimates reliable P-impedance \(Z_p\), S-impedance \(Z_s\) and bulk density \(\rho\) inverting pre-stack CDP gathers in order to predict fluid and lithology properties. Compared to post-stack inversion, pre-stack inversion takes into consideration a linear relationship between compressional velocities \(V_p\) and shear velocities \(V_s\) in water-wet clastic rocks (Castagna’s equation). In addition, \(V_p\) and \(\rho\) must be related according to Gardner’s equation. These relationships between variables help to decrease problems of noise and non-unique solutions. The algorithm offered by Hampson and Russell software is based on three assumptions: linearized approximation for reflectivity holds, PP and PS reflectivity as a function of angle can be given by the linear approximations of the Aki-Richards equations and there is a linear relationship between the logarithm of \(Z_p\) and both \(Z_s\) and \(\rho\) (which is expected to hold for the background wet lithologies). Then, final estimations of \(Z_p\), \(Z_s\) and \(\rho\) can be performed by perturbing an initial low frequency model of \(Z_p\) (Hampson and Russell, 2005).

Taking into consideration the linearized approximation of reflectivity, P-reflectivity \((R_p)\), S-reflectivity \((R_p)\) and \(\rho\)-reflectivity \((R_\rho)\) can be written as:

\[
R_p = \frac{1}{2} \left( \frac{\Delta V_p}{V_p} + \frac{\Delta \rho}{\rho} \right) \tag{15}
\]

\[
R_s = \frac{1}{2} \left( \frac{\Delta V_s}{V_s} + \frac{\Delta \rho}{\rho} \right) \tag{16}
\]

\[
R_\rho = \frac{\Delta \rho}{\rho} \tag{17}
\]

These reflectivity terms can be estimated from the angle dependent reflectivity \(R_{pp}(\theta)\) (Aki-Richards linearized approximation - equation 28) and \(\rho\) and \(V_p\) are related (Gardner’s relationship):
Small reflectivity approximation can be used to relate original $\Delta V_P/V_P$, $\Delta V_S/V_S$ and $\Delta \rho/\rho$ to their changes:

$$\frac{\Delta V_P}{V_P} \approx \Delta \ln V_P \quad (19)$$

$$\frac{\Delta V_S}{V_S} \approx \Delta \ln V_S \quad (20)$$

$$\frac{\Delta \rho}{\rho} \approx \Delta \ln \rho \quad (21)$$

Where $\ln$ is the natural logarithm. This allows invert velocities and densities rather than reflectivity. Hampson and Russell (2005) invert directly $Z_P$, $Z_S$ and $\rho$ through a small reflectivity approximation as was mentioned above.

$$Z_P = \rho V_P \quad (22)$$

$$Z_S = \rho V_S \quad (23)$$

Small reflectivity approximation for the P-wave reflectivity can be given by the combination of equations (15) and (19):

$$R_{Pi} \approx \frac{1}{2} \Delta \ln Z_{Pi} = \frac{1}{2} [\ln Z_{Pi+1} - \ln Z_{Pi}] \quad (24)$$

Where $i$ means the $i^{th}$ interface between layers $i$ and $i + 1$. This equation can be written as a matrix considering $N$ samples of reflectivity:

$$\begin{bmatrix}
R_{P1} \\
R_{P2} \\
\vdots \\
R_{PN}
\end{bmatrix} = \frac{1}{2} \begin{bmatrix}
-1 & 1 & 0 & \cdots \\
0 & -1 & 1 & \cdots \\
0 & 0 & -1 & 1 \\
\vdots & \vdots & \vdots & \ddots
\end{bmatrix}
\begin{bmatrix}
L_{P1} \\
L_{P2} \\
\vdots \\
L_{PN}
\end{bmatrix} \quad (25)$$

Being $L_{Pi} = \ln(Z_{Pi})$. Seismic trace $(T)$ resulted from convolving the Earth’s reflectivity $(R_P)$ with the seismic wavelet $(w)$, given the equation: $T = w * R_P$. This can also be written as a matrix:
The relationship between the seismic trace and the logarithm of P-impedance can be obtained combining the equations (25) and (26):

\[
\begin{bmatrix}
T_1 \\
T_2 \\
\vdots \\
T_N
\end{bmatrix} =
\begin{bmatrix}
w_1 & 0 & 0 & \cdots \\
w_2 & w_1 & 0 & \cdots \\
\vdots & \vdots & \vdots & \ddots \\
w_3 & w_2 & w_1 & \cdots \\
\vdots & \vdots & \vdots & \vdots & \ddots
\end{bmatrix}
\begin{bmatrix}
R_{P1} \\
R_{P2} \\
\vdots \\
R_{PN}
\end{bmatrix} \quad (26)
\]

\[W\] is the wavelet matrix given in equation (26) and \(D\) is the derivative matrix of equation (25). Matrix inversion will be potentially unstable and low frequency features will not be recovered from the impedance if equation (27) is inverted employing standard matrix inversion techniques in order to obtain \(L_P\) (knowing \(T\) and \(W\)). Therefore, an initial low frequency impedance model is constructed and then iterate until obtain a solution employing the method of conjugate gradients.

Aki-Richards equation can be written as:

\[R_{pp}(\theta) = c_1R_p + c_2R_s + c_3R_D \quad (28)\]

Where:

\[c_1 = 1 + tan^2 \theta \quad (29)\]

\[c_2 = -8\gamma^2 tan^2 \theta \quad (30)\]

\[c_3 = -0.5tan^2 \theta + 2\gamma^2 sin^2 \theta \quad (31)\]

\[\gamma = V_s/V_p \quad (32)\]

For an angle dependent trace \(T(\theta)\), equation (27) can be extended combining this with equation (28):

\[T(\theta) = \left(\frac{1}{2}\right)c_1W(\theta)DLP + \left(\frac{1}{2}\right)c_2W(\theta)DL_S + W(\theta)c_3DL_D \quad (33)\]

Being \(L_S = ln(Z_s)\) and \(L_D = ln(\rho)\). The wavelet now is dependent of the angle. This equation does not take into consideration the relationship between \(L_P\) and \(L_S\) and between \(L_P\) and \(L_D\). Relationships are different since impedance is being used instead of velocity. The objective is tried to look for deviations away from the lineal trend in logarithmic scale.
\[
\ln(Z_S) = k\ln(Z_P) + k_c + \Delta L_S \quad (34)
\]
\[
\ln(Z_D) = k\ln(Z_P) + m_c + \Delta L_D \quad (35)
\]

Next equation is obtained combining equations (33) and (35):

\[
T(\theta) = e_1 W(\theta) DL_p + e_2 W(\theta) DL_s + W(\theta)c_3 DL_D \quad (37)
\]

Where:

\[
e_1 = \left(\frac{1}{2}\right) c_1 + \left(\frac{1}{2}\right) kc_2 + mc_3 \quad (38)
\]
\[
e_2 = \left(\frac{1}{2}\right) c_2 \quad (39)
\]

Equation (37) also can have matrix form:

\[
\begin{bmatrix}
T(\theta_1) \\
T(\theta_2) \\
\vdots \\
T(\theta_N)
\end{bmatrix} =
\begin{bmatrix}
e_1(\theta_1)W(\theta_1)D & e_2(\theta_1)W(\theta_1)D & c_3(\theta_1)W(\theta_1)D \\
e_1(\theta_2)W(\theta_2)D & e_2(\theta_2)W(\theta_2)D & c_3(\theta_2)W(\theta_2)D \\
\vdots & \vdots & \vdots \\
e_1(\theta_N)W(\theta_N)D & e_2(\theta_N)W(\theta_N)D & c_3(\theta_N)W(\theta_N)D
\end{bmatrix}
\begin{bmatrix}
L_p \\
\Delta L_S \\
\Delta L_D
\end{bmatrix} \quad (40)
\]

This matrix presents the same problem mentioned above if matrix inversion methods are applied (low frequency content is missed). For this reason, a practical approach proposed by Hampson and Russell is to initialize the solution to:

\[
[L_p \quad \Delta L_S \quad \Delta L_D]^T = [\ln(Z_{p0}) \quad 0 \quad 0]^T \quad (41)
\]

Where \(Z_{p0}\) is the initial low frequency impedance model (Hampson and Russell, 2005).
5. **Data and Processing**

A methodology was followed in order to perform post-stack and pre-stack inversions. Figure 5.1 shows a diagram with the applied workflow.
3D Full Stack Seismic (Q16 Block)

During the phase 1 of this study, a 3D pre-stack time migrated (PSTM) full-stack seismic data was used. The characteristics regarding the acquisition and processing are shown in the Table 5.1. Also, the seismic area and geometry, together with the location of ten wells, are illustrated in the Figure 5.2.

<table>
<thead>
<tr>
<th>Seismic Features Q16</th>
<th>3D Seismic Full Stack Pre-stack Time Migrated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seismic type</td>
<td>3D Seismic Full Stack</td>
</tr>
<tr>
<td>Area</td>
<td>256 km²</td>
</tr>
<tr>
<td>Bin size</td>
<td>25m x 25m</td>
</tr>
<tr>
<td>Offsets</td>
<td>From 300 to 3300 m</td>
</tr>
<tr>
<td>Sample rate</td>
<td>4ms</td>
</tr>
<tr>
<td>Record length</td>
<td>5000ms</td>
</tr>
<tr>
<td>Inline Azimuth</td>
<td>51.7 degrees</td>
</tr>
<tr>
<td>Number of Inlines</td>
<td>844 (from 1070 to 1913).</td>
</tr>
<tr>
<td>Number of Crosslines</td>
<td>716 (from 5009 to 5724).</td>
</tr>
<tr>
<td>Acquisition recording polarity (SEG)</td>
<td>• Hard kicks are peaks (positive amplitudes, blue).</td>
</tr>
<tr>
<td></td>
<td>• Soft kicks are troughs (negative amplitudes, red).</td>
</tr>
<tr>
<td>Display Polarity</td>
<td>• Hard kicks are troughs (negative amplitudes, red).</td>
</tr>
<tr>
<td></td>
<td>• Soft kicks are peaks (positive amplitudes, blue).</td>
</tr>
<tr>
<td>Seismic data processing</td>
<td>1. Refraction statics correction.</td>
</tr>
<tr>
<td></td>
<td>2. Spherical divergence compensation.</td>
</tr>
<tr>
<td></td>
<td>3. Shot domain noise attenuation.</td>
</tr>
<tr>
<td></td>
<td>4. Zero phasing.</td>
</tr>
<tr>
<td></td>
<td>5. Tau-P domain deconvolution.</td>
</tr>
<tr>
<td></td>
<td>6. Velocity analysis.</td>
</tr>
<tr>
<td></td>
<td>7. Residual statics.</td>
</tr>
<tr>
<td></td>
<td>8. Velocity analysis.</td>
</tr>
<tr>
<td></td>
<td>10. Surface consistent amplitude compensation.</td>
</tr>
<tr>
<td></td>
<td>11. CDP domain noise attenuation.</td>
</tr>
<tr>
<td></td>
<td>12. Normal moveout correction.</td>
</tr>
<tr>
<td></td>
<td>15. Residual moveout correction.</td>
</tr>
<tr>
<td></td>
<td>16. NMO mute.</td>
</tr>
<tr>
<td></td>
<td>17. CMP stack.</td>
</tr>
<tr>
<td></td>
<td>18. Predictive deconvolution (Gap 24ms).</td>
</tr>
<tr>
<td></td>
<td>19. FXY noise attenuation.</td>
</tr>
</tbody>
</table>

Table 5.1 3D seismic (full stack) features.
The 3D seismic volume and well information (locations, deviations, logs and tops) were loaded in Petrel Software and a quality control of the data was done. Polarity of the seismic was checked. Moreover, high signal/noise ratio and clear reflectors could be seen in the data until approximately 2500ms of depth. Structurally, continuous reflectors are distinguished until approximately 1700ms. Below these, the reflectors look discontinuous and separated by normal and/or inverted faults that are assumed to be consequence of rifting and then inversion phases. In other words, horsts and grabens features are observed below 1700ms. A seismic composite line passing through most of the wells can be seen in the Figure 5.3.

Figure 5.2 3D seismic area and well locations.
Wells

Well information: locations, deviations, Kelly Bushing (KB), logs, tops and checkshots, was obtained from the public database: http://nlog.nl/nl/home/NLOGPortal.html and from the company (Client) who supplied the seismic data. Extracting, processing and doing the quality control of the well information from the public database (PD) took a considerable amount of time due to the large quantity of logs. Moreover, sometimes those logs were at different depth intervals. Table 5.2 shows information of location coordinates, KB, measured depth (MD) and true vertical depth sub-sea (TVDSS) of ten wells found within the seismic area. TVDSS were calculated with deviation files that contained azimuth and inclination values of each well.

<table>
<thead>
<tr>
<th>Well</th>
<th>X coordinate (m)</th>
<th>Y coordinate (m)</th>
<th>KB (m)</th>
<th>MD (m)</th>
<th>TVDSS (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q16-03</td>
<td>569026.64</td>
<td>577713.65</td>
<td>40.60</td>
<td>0 to -2660</td>
<td>40.6 to -2619.19</td>
</tr>
<tr>
<td>Q16-04</td>
<td>570497.51</td>
<td>5774657.02</td>
<td>31.00</td>
<td>0 to -3839</td>
<td>31.0 to -3805.08</td>
</tr>
<tr>
<td>Q16-05</td>
<td>570560.30</td>
<td>5769981.59</td>
<td>39.60</td>
<td>0 to -2979</td>
<td>39.6 to -2938.97</td>
</tr>
<tr>
<td>Q16-08</td>
<td>572606.00</td>
<td>5765132.00</td>
<td>35.00</td>
<td>0 to -4103</td>
<td>35.0 to -3746.39</td>
</tr>
<tr>
<td>Q16-FA-101-S1</td>
<td>571791.50</td>
<td>5768716.76</td>
<td>39.10</td>
<td>0 to -4060</td>
<td>39.1 to -3945.81</td>
</tr>
<tr>
<td>P18-02</td>
<td>565845.00</td>
<td>5773939.49</td>
<td>33.50</td>
<td>0 to -3754.75</td>
<td>33.5 to -3706.25</td>
</tr>
<tr>
<td>MSG-01</td>
<td>571151.00</td>
<td>5759808.00</td>
<td>13.58</td>
<td>0 to -4259.42</td>
<td>13.58 to -3375.86</td>
</tr>
<tr>
<td>MSG-02</td>
<td>571154.97</td>
<td>5759777.38</td>
<td>13.96</td>
<td>0 to -4218</td>
<td>13.96 to -2960.74</td>
</tr>
<tr>
<td>MSG-03</td>
<td>571892.99</td>
<td>5759522.72</td>
<td>13.75</td>
<td>0 to -5083</td>
<td>13.75 to -3029.99</td>
</tr>
<tr>
<td>MSV-01-S2</td>
<td>571939.00</td>
<td>5756405.00</td>
<td>14.48</td>
<td>0 to -2725</td>
<td>14.48 to -2554.67</td>
</tr>
</tbody>
</table>

Table 5.2 Well information.
Well-logs: gamma ray (GR), P-wave (DT), S-wave (DTSM), bulk density (RHOB), neutron-porosity (NPHI) and deep resistivity (ILD) were loaded in Petrel Software. Table 5.3 illustrates at what measure depths this information was found within each well and also, the differences of these depths according to the public database and the Client. Moreover, well-tops and only five checkshots were downloaded from the public database. GR, DT, RHOB, NPHI and ILD well-logs were quite complete, while there were a lack of information regarding the DTSM well-logs and checkshots. Only the Client provided logs from well MSG-3, but not for the entirely depth interval.

MD, logs and tops from wells Q16-03 and Q16-FA-101-S1 can be observed in the Figures 5.4 and 5.5. Pictures of logs from other wells can be found in the Appendix A: Initial well-log information.

A well correlation was done from approximate South (onshore – proximal) to North (offshore – distal) using GR logs in order to observe the most important and continuous top formations. In Figure 5.6 is observed that top formations such as Ommelanden and Texel are very continuous in the area. Top Posidonia Shale is only present in offshore wells. This Formation shows very high GR reading comparing to other formations. Basal Solling Sandstone Member and Rogenstein Member also show very distinguished tops that can be found in deeper wells.
Table 5.3 Measured depths of well-log information provided by the public database and the Client. Depths of checkshot data is in TVDSS.

<table>
<thead>
<tr>
<th>Well</th>
<th>GR</th>
<th>DT</th>
<th>DTS</th>
<th>RHOB</th>
<th>NPHI</th>
<th>ILD</th>
<th>Checkshot</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q16-03</td>
<td>PD: 591.5-2646.1m</td>
<td>PD: 725.2-2646m</td>
<td>PD: 593.1-2661.2m</td>
<td>PD: 1429.8-2661.2m</td>
<td>PD: 585.8-2658.6m</td>
<td>PD: 0-2597.5m</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 586.5-2650.9m</td>
<td>Client: 590-2647m</td>
<td>Client: 1432.8-2659.9m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>Q16-04</td>
<td>PD: 34.3-3828.7m</td>
<td>PD: 761.3-3819.8m</td>
<td>PD: 710.7-3821.7m</td>
<td>PD: 536.7-3817.7m</td>
<td>PD: 532.3-3837.7m</td>
<td>PD: -</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 30.1-3808.8m</td>
<td>Client: 534.4-3818.4m</td>
<td>Client: 532.1-3808.9m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>Q16-05</td>
<td>PD: 48.8-2669.4m</td>
<td>PD: 652.6-2664m</td>
<td>PD: 639.2-2601.2m</td>
<td>PD: 639.2-2594.8m</td>
<td>PD: 650.8-2677.5m</td>
<td>PD: 0-2939.2m</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 62.4-2664.7m</td>
<td>Client: 652.6-2663.9m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>Q16-08</td>
<td>PD: 21.2-4070.8m</td>
<td>PD: 1009.9-4084.8m</td>
<td>PD: 1012.2-4078.8m</td>
<td>PD: 3769.9-4080.7m</td>
<td>PD: 3769.9-4104.7m</td>
<td>PD: -</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 19.7-4070.9m</td>
<td>Client: 1009.9-4089m</td>
<td>Client: 1010.9-4076.2m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>Q16-FA-101-S1</td>
<td>PD: 19.4-4015.7m</td>
<td>PD: 931.3-3656.5m</td>
<td>PD: 917.6-4018.9m</td>
<td>PD: 918.2-4012.2m</td>
<td>PD: 931.2-3671.3m</td>
<td>PD: 0-3938m</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 29.4-4051.5m</td>
<td>Client: 940.1-4048m</td>
<td>Client: 940.1-4047.8m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>P18-02</td>
<td>PD: 35.1-3752.6m</td>
<td>PD: 398.7-3519.8m</td>
<td>PD: 1838.1-3770m</td>
<td>PD: 1849.8-3764m</td>
<td>PD: 401-3765.7m</td>
<td>PD: -</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 22.9-3765.4m</td>
<td>Client: 364.4-3513.5m</td>
<td>Client: 3061.7-3509.7m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>MSG-01</td>
<td>PD: 1074.8-4259.8m</td>
<td>PD: 2427.1-4244.9m</td>
<td>PD: 2427.3-4260m</td>
<td>PD: 2427.4-4254.8m</td>
<td>PD: 2427.7-4272.7m</td>
<td>PD: 0-3372.9m</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 1074-4259.8m</td>
<td>Client: 2427.1-4244.9m</td>
<td>Client: 2427.3-4303.7m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>MSG-02</td>
<td>PD: 1645.2-4209.8m</td>
<td>PD: 3935.2-4179.7m</td>
<td>PD: 3935.2-4153.7m</td>
<td>PD: 3935.2-4157.8m</td>
<td>PD: 3935.9-4224.7m</td>
<td>PD: -</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 1645-4209.8m</td>
<td>Client: 3935.3-4179.7m</td>
<td>Client: 3935.3-4153.7m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>MSG-03</td>
<td>PD: 124.4-5069.8m</td>
<td>PD: 4428.3-5020.8m</td>
<td>PD: 4428.3-5020m</td>
<td>PD: 4449-5035.5m</td>
<td>PD: -</td>
<td>PD: -</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 124.4-5069.8m</td>
<td>Client: 4449-5021m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
<tr>
<td>MSV-01-S2</td>
<td>PD: 10.4-2722.8m</td>
<td>PD: 1210.3-2573.8m</td>
<td>PD: 2024.2-2589.9m</td>
<td>PD: 2024.2-2583.8m</td>
<td>PD: 2023.4-2727.7m</td>
<td>PD: 1151.7-2404.2m</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Client: 10.4-2723m</td>
<td>Client: 1211.1-2570.3m</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td>Client: -</td>
<td></td>
</tr>
</tbody>
</table>
Figure 5.4 Well-logs Q16-03.

Figure 5.5 Well-logs Q16-FA-101-S1.
Figure 5.6 Well-log correlation from proximal to distal using GR logs.
Well-Seismic Tie

Checkshots or time-depth relationships of five wells were used in order to generate the first synthetic seismograms. Figure 5.7 shows curves of TVDSS versus two way time (TWT). Maximum depths reached are about 4000 meters, which in TWT is approximately 2500 ms. It is observed that the checkshots of the five wells are very similar, which gives confidence in the well-seismic tie procedure. Checkshots with large differences could bring problems positioning the wells in the right time.

Petrel Software calculates acoustic impedance, \( Z_p = V_p \rho \), from P-wave (\( V_p \)) and bulk density (\( \rho \)) well-logs. Then, a reflectivity or reflection coefficients (RC) can be estimated, \( RC = \frac{Z_2-Z_1}{Z_2+Z_1} \).

A Butterworth wavelet was convolved with the reflectivity series calculated at each well to create a synthetic trace. The wavelet is constant zero phase with a sample rate of 2ms, length of 100ms, low cut frequency of 10Hz, high cut frequency of 50Hz, low frequency slope of 18 dB/octave and high frequency slope of 72 dB/octave (Figure 5.8).

![Figure 5.7 Checkshots of five wells. TVDSS (Z) versus TWT.](image)

![Figure 5.8 a) Butterworth wavelet. b) Power spectrum.](image)
Figures 5.9 and 5.10 show examples of synthetic seismograms being compared with original seismic (section of one km) at locations of the wells Q16-03 and Q16-FA-101-S1. The idea is that the synthetics resemble the original seismic having a similar content of frequency and the wells have the right positioning in time. Moreover, Figure 5.11 illustrates well-seismic tie in a composite line that passes through eight wells.
Figure 5.11 Seismic composite line with the synthetic seismograms generated at each well (Well-seismic tie).
Seismic Interpretation

The initial well-seismic tie (ten wells) was used only to guide the interpretation. The well-seismic tie is an important step for the inversion process and it was fine tuned during phase 2 (see workflow chart on Figure 5.1). Nevertheless, this well-seismic tie allowed interpreting important reflectors.

Top Ommelanden Formation shows a suddenly increase in acoustic impedance due the increment of Vp and $\rho$. It is a well distinguished hard kick reflector related with the fact that the Ommelanden Formation is a limestone. The GR well-log shows very low values at this interval that is consistent with the presence of carbonate rocks.

Vp and $\rho$ decrease at Top Texel Formation might be because the presence of marls. In consequence, Zp decreases, which is indicative of a soft kick. Moreover, GR readings increase compared to the above formation.

Top Posidonia Shale Formation, which presents very high GR values due to its organic matter content, also illustrates a soft kick, but the change is gradual. This increase in density and velocity might be related with the presence of organic matter and/or hydrocarbon.

Regarding the top (Top Basal Solling Sandstone Member) and base (Top Rogenstein Member) of the Bunter reservoir, the former one is considered a soft kick due the suddenly decrease in Zp, which could be related with the presence of gas. The latter one is difficult to define because changes in velocities are small and $\rho$ looks to suffer an increment, giving a hard kick. These little differences in acoustic impedances might be because the lower part of the Bunter reservoir (Volpriehausen Formation) is cemented by calcite and dolomite given high densities, which overlap with the high densities of the Rogenstein Formation, which consists on anhydritic claystones. The anhydrite mineral has a high density. Moreover, the entire interval of the Bunter reservoir has very low GR values comparing with the above shale formations, Solling and Rot Claystone Members, and below shale formations, Rogenstein and Main Claystone Members.

Comparing the real seismic with the synthetic seismograms (Figure 5.12), it was also noticed that the amplitudes of shallower reflector like top Ommelanden and top Texel are sharper than amplitudes of deeper reflectors like top of Posidonia, top Basal Solling Sandstone and top Rogenstein. This is because the frequency content is being lost as depth increases, causing less temporal resolution. The Posidonia Shale gives a very characteristic reflection that presents very low frequencies and can be recognised easily in seismic sections. The Base of Cretaceous Unconformity can be recognised very well in seismic when Cretaceous package of reflectors lie unconformably over Jurassic ones.

Figure 5.13 shows a composite line with the seismic interpretation of six reflectors: Top Ommelanden Formation (orange), Top Texel Formation (magenta), Base of Cretaceous Unconformity (green), Top Posidonia Shale Formation (yellow) and two reflectors close to the Bunter reservoir (pink and blue). These interpretations were based on the well-seismic tie and the characteristic acoustic impedances mentioned above, taking into consideration mostly
the wells with checkshots. The same composite line can be observed with the GR logs displayed in the Figure 5.14. Describing the seismic section, according to seismic stratigraphy, it can be observed a transparent package of more or less continuous reflectors between Top Ommelanden and Top Texel. Another package of continuous reflectors, but with stronger amplitudes is being characterised between Top Texel and Base of Cretaceous Unconformity, which is hard to recognise as it moves north or offshore. Below this Unconformity, reflectors are not continuous anymore; a lot of folds and faults can be seen and laterally the amplitudes change excepting in the Posidonia Shale. Onshore, this Formation is not observed and assuming that it has been eroded.
Figure 5.12 a) Top Ommelanden Formation (Hard kick). b) Top Texel Formation (Soft kick). c) Top Posidonia Shale Formation (Soft kick). d) Top Basal Solling Sandstone Member (Soft kick) and Top Rogenstein Member (Hard kick, difficult to define due to little change in sonic and density logs).
Figure 5.13 Seismic interpretations: Top Ommelanden Formation (orange), Top Texel Formation (magenta), Base of Cretaceous Unconformity (green), Top Posidonia Shale Formation (yellow), two horizons close to the Bunter Reservoir (pink and blue).
Figure 5.14 Composite line with the interpreted horizons and the GR-logs displayed. A major normal fault can be seen in black. Top Ommelanden Formation (orange), Top Texel Formation (magenta), Base of Cretaceous Unconformity (green), Top Posidonia Shale Formation (yellow), two horizons close to the Bunter Reservoir (pink and blue).
All the horizons were interpreted every 5 inlines and 5 crosslines generating a very tight grid, excepting for the Top Posidonia Shale Formation horizon that was interpreted every 1 inline and 1 crossline. Then, a 3D snap followed by a 3D autotracking were performed. The snap procedure put the picked points in the right trough or peak depending if it was a hard or soft kick. The autotracking filled the inlines and crosslines that were not interpreted, looking for the right reflector. Top Posidonia Shale Formation horizons did not need autotracking. The performance of the autotracking is very important for the horizons that are close to the Bunter reservoir because these reflectors are very discontinuous due to the presence of faults. Subsequently, these horizons were smoothed.

These interpreted horizons constitute a very important input in the performing of the inversion process. They will drive the lateral interpolation between the well-logs during the building of the low frequency models. As well, these horizons could be used for time-depth conversion purpose, but in this study everything was kept in two way travel time.

Final structural maps in TWT of the interpreted horizons can be seen in the Figures 5.15 to 5.20. Top Ommelanden and Top Texel show a NW-SE trend, dipping to the SW. The depths vary from about 600ms at the northeast to approximate 1200ms at the southwest. There is an area located in the southeast that does not have data.

Figure 5.15 Top Ommelanden Fm Map.               Figure 5.16 Top Texel Fm Map.
The Base of Cretaceous Unconformity map shows more or less a constant depth of 1800ms excepting at some shallower locations at the northeast (between 1500 and 1700ms) and other deeper areas at north-northwest that can reach 1950ms. A major fault with northwest-southeast strike can be observed close to the crossline 5309.

The top of the Posidonia Shale Formation was not interpreted at the southwest of the major normal fault mentioned above (Figure 5.14). It was interpreted only in the offshore area and it is assumed eroded in the onshore part. This Formation is very faulted. Faults show northwest-southeast trends. Depths vary from about 1700ms to 2400ms showing two deepest areas to the northeast and one shallowest location to the north between crosslines 5609 and 5709. Faults in general were not interpreted during this study due to the complexity of the area. Nevertheless, fault gaps were respected during the interpretations as can be seen in detail on the maps.

![Base Cretaceous Unconf. Map](image1)

![Top Posidonia Shale Fm Map](image2)

Figure 5.17 Base Cretaceous Unconf. Map.  Figure 5.18 Top Posidonia Shale Fm Map.

The two reflections close to the Bunter reservoir are located approximately between 1800ms and 2800ms of depth. They are very faulted and therefore Bunter reservoir is interpreted to be compartmentalized. Faults show northwest-southeast trends.
At this point of the process it is concluded that the area of study, Q16 Block in West Netherlands Basin, is structurally characterized by half grabens, where the faults have a NW-SE trend. Posidonia Shale Formation and Bunter reservoir are compartmentalised and they are located at different depths, between 2300 and 2800 meters and between 2500 and 3500 meters respectively. Moreover, Posidonia Shale Formation is not found in the west of the study area and it is assumed to be eroded.

Post-stack inversion

The second phase of the workflow began after finishing the seismic interpretation. Hampson and Russell Software was used for the inversion purpose. Initially, a database was created within this software. Well information, horizons and 3D seismic were loaded.

Available seismic data comprised a 3D full stack seismic used as an input in the post-stack inversion, and 3D CDP gathers used as an input in post-stack and pre-stack inversions.
CDP Gathers

The dataset comprises of 682,877 NMO corrected CDPs. It has 805 inlines, numbered from 1109 to 1913, and 716 crosslines that go from 5009 to 5724. This is a pre-stack time migrated seismic NMO corrected. Figure 5.21 shows an example of some CDPs at inline 1248. Sonic log of the well Q16-03 can also be observed in the CDP number 210653. The interpreted horizons in the full-stack seismic are displayed in the CDP gather as well. The offset varies from 300 to 3300 meters, but analysing the data, it is observed effective traces only until approximately 2300 meters of offset. A closer look can be seen in the Figure 5.22, inline 1247 – well Q16-03.

Figure 5.21 CDP gathers (Inline 1248).
Figure 5.22 CDP gathers (Inline 1247). Base of Cretaceous (green), Top Posidonia Shale Formation (yellow), horizons close to the Bunter reservoir (pink and blue).

Stacking by Offset

A stacking by offset was done using the CDP gathers. This was performed in order to compare the different stacked volumes. Sometimes at larger offset, some CDPs look over or under corrected due to over or under estimated stacking velocities. This causes a not so accurate stacking when all offsets are used. An over-corrected NMO can be seen in the Figure 5.22 (middle CDP where the pink reflector is located) and in Figure 5.23 an example of under-corrected NMO is illustrated. Nevertheless, these under and over corrections are considered small in general. Figure 5.24 shows an example, inline 1369-Well Q16-04, of four stacking by offset: near stack offset (300-800m), near-mid stack offset (800-1300m), far-mid stack offset (1300-1800m), far stack offset (1800-2300m) and full stack offset (300-2300m). Also tops Posidonia Shale Formation (yellow) and the two horizons close to the Bunter reservoir can be observed. It is noticed that near stack offset section has more resolution where sharper reflectors can be seen than the others sections. Furthermore, far stack offset section show less information after an offset of approximately 1800 meters. In conclusion, due to this increment in details and more reliable amplitudes, the near stack offset seismic volume was used as an input for the acoustic inversion.
Figure 5.23 Example of a CDP gather (inline 1369) with an under-corrected NMO at pink reflector (Q16-04 sonic well-log). Notice also how the amplitude thickness increases at longer offsets.
Amplitude Spectrum

Amplitude spectrums were extracted from both 3D full-stack and near stack seismic volumes within a window between 500 and 3000ms, and also within a shorter window at the targets Posidonia Shale Formation and Bunter reservoir from 1700 to 2800ms (Figure 5.25). It was observed in both volumes and windows that the frequency content varies approximately from 10Hz to 70Hz.
Wavelet Extraction from Seismic

The wavelet used during the inversion process is a very important input. Firstly, wavelets were extracted from both seismic volumes, full and near offset stacks, by autocorrelation (The program call this statistical wavelet extraction). These initial wavelets were used to perform the well-seismic tie. They were characterised by the following features: constant zero phase, length of 200ms, taper length of 50ms, sample rate of 2ms, phase rotation of 180 degrees and analysis window of 2500ms of thickness, from 500 to 3000ms. Figure 5.26 illustrates the very similar wavelets extracted with their respective amplitude spectrums, showing good frequency content from 10 to 70Hz.
Figure 5.26 Wavelet extracted from seismic. a) From full-stack 3D seismic. b) From near offset-stack 3D seismic.

Well-Seismic Tie

Acoustic impedance well-logs were calculated using P-wave and density logs for each well \( Z_p = \frac{V_p \rho}{\rho} \). Hampson and Russell software calculates reflectivity coefficients \( RC = \frac{Z_2 - Z_1}{Z_2 + Z_1} \). These reflectivity coefficients are convolved with the previous extracted wavelet from the seismic and, in that way, a synthetic seismic trace is generated at the well-location. This synthetic seismic trace from the well-logs is compared with the original seismic trace from the 3D volume. Initially, these well-logs are positioning from
depth (TVDSS) to time (TWT) using checkshots available. Then this well-seismic tie can be adjusted even more (White, 1997). Figure 5.27 displays tops, GR, P-wave, density and P-impedance logs of the well Q16-03. Next to Zp, it is observed a group of blue traces, which is a synthetic trace repeated five times. This synthetic trace was obtained from the logs and the wavelet above. These blue traces are compared with the red ones next to them, which is one trace repeated also five times that illustrates the real seismic trace at the well-location. Next to the red traces is an arbitrary seismic section that passes through the well. The original seismic trace at well location also can be observed in this section (red trace). For deviated wells, the red trace is a composed trace from several inlines and crosslines. Finally, a synthetic is displayed. This is the same blue trace repeated five times showing normal polarity colours (red are troughs and blue are peaks). In this case, the seismic used was the full-stack, but this also was done for the near-offset seismic and using the other nine wells. In this well, Q16-03, the correlation looks quite good because the logs were previously positioned in TWT with a checkshot. The uncertainty in the correlations increases in other wells when the checkshots are not available or when the wells are too deviated.

![Figure 5.27 Well-seismic tie (Well Q16-03). Input: Full-stack seismic, extracted wavelet from full stack seismic. Well logs previously positioning in TWT using checkshot available.](image)

A correlation or a well-seismic tie can be improved manually. Figure 5.28 illustrates an example of that for the well Q16-03. Troughs and peaks of the synthetic trace can be adjusted manually with troughs and peaks of the real trace respectively. The improvements of
this correlation can also be seen in terms of cross-correlation between these two traces (Figure 5.29). Before manual adjustment, the maximum coefficient of the cross-correlation was 0.255; and after the improvement this increased until 0.638. Furthermore, these graphs can give an idea of the wavelet shape that can be extracted from this well. Manual corrections of correlations can improve the phase and therefore the symmetry of the wavelet. In the Figure 5.29 is observed that before the fine tuning the wavelet was shifted 10ms and after the fine tuning the wavelet is at 0ms.

Figure 5.28 Improvement of well-seismic tie (Well Q16-03). Input: Full-stack seismic, extracted wavelet from full stack seismic. a) Initial correlation. b) Manual tie improvement. c) Final result.

Figure 5.29 Cross-correlation (Well Q16-03). a) Initial maximum coefficient: 0.255. b) Final maximum coefficient: 0.638.
Wavelet extraction from wells

After doing the well-seismic ties, a new full wavelet was extracted from the well-logs (Figures 5.30 and 5.31). This is used to determine the full amplitude and phase spectrum of the wavelet by finding an operator in time domain that shapes the well-log reflectivity to the seismic composite trace. The effects of log correlation like stretching and picking of data are incorporated into the logs that are used in wavelet extraction. This process calculates an exact wavelet, but it is very sensitive to the tie between logs and data. A timing or stretch error can cause features like loss of high frequency in the wavelet, distortion of the phase spectrum and generation of unrealistic side-lobes.

Several wells were employed in the extraction of the wavelet. In this case, offshore wells were used with less uncertainty in their correlation with the seismic. Onshore wells do not have enough data regarding their sonic and density logs, and therefore their wavelets are not so good to use them.

Figure 5.30 Wavelet extracted from well-logs. a) Well Q16-03. b) Well Q16-04. c) Well Q16-05. d) Well Q16-08. e) Well Q16-FA-101-S1. f) Using the five well mentioned from a) to e). The seismic used was the full-stack.
In conclusion, the extraction of the wavelets from the well-logs is very sensitive to the well-seismic tie, which was previously fine-tuned manually. The wavelets used as inputs for the inversions are considered accurately estimated due to their symmetrical shape observed, although the side lobes are slightly different. These differences in the side lobes can be related to small errors in the well-seismic ties that introduce noise to the estimated wavelets.
Low Frequency Model

After having the wells tied to the seismic, a low frequency acoustic impedance model was built. This model is based on well-logs, horizons interpreted and RMS velocities. Figure 5.32 illustrates a composite line that passes through eight wells. It can be observed the input full stack seismic and its respective low frequency model. The idea is to have a very smooth initial model where the lateral geometry of the model is guided by the horizons since this study area is characterised by half-graben features. In consequence, the output models have structural geological meaning. Vertically, the low frequency variations are given by the well-logs. The provided seismic does not have frequencies below 10 Hz (Figure 5.25).

Inversion Analysis

Having the 3D seismic, wavelet and initial low frequency acoustic impedance model as inputs, a model-based, with hard constraints, acoustic inversion process was performed at well locations, generating inverted synthetic logs of acoustic impedance. The original, initial modeled and inverted Zp logs were compared. Moreover, the original seismic trace at well-locations was compared with the synthetic one calculating the error. Figures 5.33 and 5.35 show this process for wells Q16-03 and Q16-04. In general, it is noticed a very good matching trend between the smoothest black curve (initial low frequency model), the blue curve (original Zp log) and the inverted Zp log (red one). The synthetic seismic trace is very similar to the original one, having a very small error. A closer look to Posidonia Shale interval can be observed in Figure 5.34. Blue and red curves follow the same trend, but in this case, it was hard to match the real value of acoustic impedance. The black trace is very smooth as it should be. Figure 5.36 illustrates a better matching between the modeled Zp log and the real one at Posidonia Shale interval. On the other hand, even though these logs follow the same trend at Bunter reservoir, they do not match perfectly well.
Figure 5.32 a) Composite full-stack seismic line with synthetic seismograms at well locations. b) Initial low frequency acoustic impedance model with original Zp logs at well locations.
Figure 5.33 Inversion analysis for the well Q16-03. Original log (blue), initial model (black) and inverted log (red). Input seismic: near-offset stack.

Figure 5.34 Closer look to the inversion analysis at Posidonia Shale interval for the well Q16-03. Original log (blue), initial model (black) and inverted log (red). Input seismic: near-offset stack.
Figure 5.35 Inversion analysis for the well Q16-04. Original log (blue), initial model (black) and inverted log (red). Input seismic: full stack.

Figure 5.36 Closer look to the inversion analysis at Posidonia Shale and Bunter intervals for the well Q16-04. Original log (blue), initial model (black) and inverted log (red). Input seismic: full stack.
Another way of doing the quality control during the inversion analysis is by generating a crossplot of Zp-inverted log versus Zp-original log. Theoretically, a linear trend between these two logs, where the slope of the lineal regression is one, means that the Zp-inverted log is the same as the Zp-original log. Figure 5.37 illustrates this crossplot for the entire log intervals. The slope of this lineal trend is 0.82, which is considered good.

$$Z_p^{(inverted)} = 0.82Z_p^{(original)} + 1552.27$$

![Figure 5.37 Crossplot Zp (inverted log) versus Zp (original log). Input: Full-stack seismic.](image)

After the inversion analysis at each well, the model based, with hard constraints, acoustic inversion process was applied to the entire full stack and near-offset stack seismic volumes. Acoustic impedance composite lines, resulting from both seismic inputs, are given in Figures 5.38 and 5.39 respectively. Original Zp logs were displayed at well-locations. In general, acoustic impedance models honour the well-log data. P-impedances vary from about 4.36 to 14.18 MPa*s*m$^{-1}$ (4360 to 14180 m/s*gr/cc). Comparing both outputs, section from Figure 5.39 looks noiser than the section from Figure 5.38. At target intervals, Posidonia Shale and Bunter Reservoir, it is not observed any particular improvement between these two sections, the results are very similar. Posidonia shale interval is characterised by low acoustic impedance compared with values from the formations below and above. Therefore, the base of the Posidonia could be interpreted from these results. On the other hand, Bunter reservoir is more difficult to characterise due to several reasons. Firstly, wells at that interval were too deviated except in Q16-04, increasing the uncertainty during the well-seismic tie phase. Secondly, the base of the reservoir, Top Rogenstein Member, is hard to recognise in terms of acoustic impedance because the velocity and density do not change too much. The above Formation, Lower Volpriehausen Sandstone Member, even though it is composed of sandstone, is well cemented and considered a tight gas formation.
Acoustic Impedance (Full-stack Seismic Input)

Final acoustic impedance volume which honour the well-log data.

Figure 5.38 Model based acoustic inversion (input: full-stack seismic).
Figure 5.39 Model based acoustic inversion (input: near-offset stack seismic).

Final acoustic impedance volume which honour the well-log data.
Pre-Stack Simultaneous Inversion

A pre-stack simultaneous inversion was carried through after the model-based acoustic inversion. The input seismic was the CDP gathers and S-wave well-logs were calculated.

**Angle Gathers**

The CDP gathers, showing an example in Figure 5.40, were transformed to angle gathers using a RMS velocity volume (Figure 5.41). A group of CDP gathers coloured by angle can be observed in the Figure 5.42. As offsets vary from 300 to 2300m, angles vary from 0 to 30 degrees. Thus, an angle gather was generated from 0 to 30 degrees (Figures 5.43 and 5.44). Traces after 30 degrees were muted. This angle gathers show a relatively good NMO correction.

![Figure 5.40 CDP Gathers (Inline 1559).](image)
Figure 5.41 RMS-velocities (Inline 1559).

Figure 5.42 CDP gathers coloured by angle (Inline 1559).
Shear Wave Calculation (Well-logs)

Shear wave logs were estimated by the Xu-White model (Xu and White, 1995 and 1996). Figure 5.45 illustrates a schematic process of how Xu-White model works in Hampson and Russell software. It is an iterative process where the initial aspect ratios of the
sandstones and shales are $\alpha_{\text{sand}} = 0.12$ and $\alpha_{\text{shale}} = 0.03$ respectively. The input logs are P-wave velocity, total effective porosity, bulk density and shale volume. The total effective porosity was calculated by the bulk density, neutron-porosity and deep resistivity logs. The shale volume was estimated by the gamma ray log. Xu-White model use Kuster-Toksöz method for calculating the dry rock properties and then fill them with fluid through the Gassman method. Subsequently, P-wave velocity is calculated with this filled rock properties and compared with the original one. If these two match, then the S-wave velocity is estimated. If they do not, then the aspect ratios for sand and shale are changed until both (real and modeled P-wave velocities) are similar. See Appendix C for more information.

![Figure 5.45 Xu-White Process (modified from Hampson and Russell tutorial).](image)

Well P18-A-02 is located to the North of the seismic area. This well has original P-wave and S-wave logs at Bunter Reservoir interval. Therefore, estimations of P-wave and S-wave using Xu-White model could be compared with these original ones. Figure 5.46 displays the logs of this well focusing in the interval between Top Basal Solling Sandstone Member and Top Rogenstein Member. The first column shows the well-top formations; the first track illustrates a very constant caliper, which is interpreted as no caves or/and mud cakes are affecting other property measurements; GR and Vsh calculated are observed in second and third tracks respectively. Vsh was calculated with the formula:

$$V_{\text{sh}} = \frac{\rho_{\text{sh}} - \rho_{\text{water}}}{\rho_{\text{water}}} \times V_{\text{sh}}^{\text{original}}$$
Where \( GR_{ss} \) and \( GR_{shale} \) are the end member values of sandstone and shale respectively. Bulk density and neutron-porosity logs were plotted together in the fourth track in order to visualize gas effect, where both logs decrease. Conversely, shales found above and below the Bunter reservoir show an increasing in bulk density and neutron-porosity logs. Deep resistivity, water saturation and porosity can be observed in tracks five, six and seven respectively. Porosity was calculated from bulk density and deep resistivity. The equation used for calculate the porosity was:

\[
\phi = \frac{0.9 \left[ \frac{\rho_{obs}}{\rho_{t}} \right]^{x} (\rho_{ma} - \rho_{h}) + (\rho_{ma} - \rho_{obs})}{(\rho_{ma} - \rho_{h})}
\]

Where \( \rho_{t} \) is the true resistivity from the log and \( \rho_{obs} \) is the observed density from the log. The density of formation water (\( \rho_{w} \)), assumed brine, had a value of 1.09 gr/cc. The fluid considered was gas, with a constant density (\( \rho_{h} \)) of 0.1 gr/cc. Even though the matrix density (\( \rho_{ma} \)) for a sandstone rock is 2.65 gr/cc, it is important to consider that for this reservoir, these sandstones can be cemented by calcite and dolomite, which increases the density. Therefore a matrix density of 2.8 gr/cc was used. The resistivity of formation water (\( Rw \)) was assumed to be 0.03 ohm.m. Water saturation (\( Sw \)) was determined by Archie’s equation:

\[
S_{w}^{n} = \frac{a}{\rho_{ma}^{m}} \times \frac{R_{w}}{R_{t}}
\]

Where the cementation factor (\( a \)) is 1, the cementation exponent (\( m \)) is 2 and the saturation exponent (\( n \)) is also 2.

Tracks 8, 9 and 10 display a comparison between the real P-wave, S-wave and Poisson’s ratio logs (red) with the modeled logs (blue). Errors between modeled and original velocities logs can be seen in tracks 11 and 12. It is appreciated that the error in S-wave is larger than in P-wave.
Figure 5.46 Display of P18-A-02 well-logs. S-wave log estimation based on models P-wave using Xu-White Method.
S-wave velocity well-logs were calculated for all the wells within the seismic area excepting for MSG-03, which already has an S-wave well-log. The calculated values were compared with original ones by plotting S-wave velocities versus P-wave velocities of several wells. This crossplot can be observed in the Figure 5.47, blue points belong to well-logs taken from the public nlog database of 21 wells located in blocks Q and P, while violet points are located within the seismic area Q16 and they are conformed by original Vp and calculated Vs using Xu-White Model. The calculated points fall within the same area of the crossplot where the original points are located, although slightly in the upper boundary. For this reason, the shear wave velocity well-logs calculated using the Xu-White Model, are considered to be accurate estimated at Bunter reservoir interval.

![Figure 5.47 Crossplot Vs versus Vp at Bunter reservoir interval from 30 wells (Blocks Q and P). Blue points are Vp and Vs values from nlog public database and violet points are original Vp and Vs values calculated using Xu-White Model.](image)

A linear regional trend was used outside the reservoir in order to calculate the shear wave velocity. Figure 5.48 shows a crossplot of Vs versus Vp with information of 21 wells from blocks Q and P. The yellow points are original well-log data from Bunter reservoir, while the gray points are original well-log data from the shales found above and below the reservoir. It is observed that the sandstones are above the shales.

Shear wave velocities were estimated at Posidonia Shale Formation also with the Xu-White Model. Only three wells are present with original Vs at this interval. Posidonia Shale is located between 1200 and 1800 meters in wells K18-08 and MDZ-02, while this Formation is located around 2460 meters in well P06-10. Figure 5.49 illustrates a crossplot of Vs versus Vp at Posidonia Shale Formation interval. Although there are few original data and the
uncertainty of the calculation increases, the estimated points fall in the same region as the original ones in the crossplot at the Posidonia Shale interval, which was considered a good sign and hence an acceptable estimation. The shear wave velocity well-logs of other intervals, from Ommelanden to Zechstein Formations, were estimated from linear trends found in crossplots Vs versus Vp generated from log data of several wells located in the blocks P, Q and K.

Figure 5.48 Crossplot Vs (m/s) versus Vp (m/s) from 21 wells (Blocks Q and P). Yellow points belong to the Bunter reservoir. Gray points belong to the shales found above and below the reservoir.

Figure 5.49 Crossplot Vs versus Vp from nine wells at Posidonia Shale Formation interval. Round points are Vs estimated with the Xu-White Model. Square and triangle points are original Vs well-log data.
Wavelet Extraction

A wavelet was extracted from the angle gathers in order to do the first well-seismic tie. The parameters are similar to the wavelets generated for the post-stack inversion: the window used was from 500 to 3000ms, the wavelet length is 200ms, the taper length is 50ms, the sample interval is 2ms and it has a phase rotation of 180 degrees due to the displayed polarity. Because the input are angle gathers, two wavelets angle dependent were created: from 1 to 15° and from 15 to 30° (Figure 5.50). The first wavelet with higher content of frequencies was employed to match well with seismic at shallower depths and the second wavelet was used to perform well-seismic tie at deeper places. Subsequently, a wavelet was generated from the well-logs (Figure 5.51). This wavelet show a good symmetry concerning the time shift, which is close to 0ms and a frequency content between approximately 10 and 70Hz. The slightly differences in the side lobes are attributed to the small time shift.

![Figure 5.50 Wavelet extracted from seismic (input: angle gathers). Angles from 1 to 15°.](image_url)
**Figure 5.51 Wavelet extracted from wells.**

**Well-Seismic Tie**

Well-seismic match for well Q16-03 and Q16-FA-101-S1 are given in the Figures 5.52 and 5.53 respectively. While a good fit between the synthetic trace (blue) and the real one (red) can be obtained in both wells. Other well-seismic ties can be observed in the Appendix B.
Figure 5.52 Well-seismic tie (Well Q16-03). Input seismic: angle gathers.

Figure 5.53 Well-seismic tie (Well Q16-FA-101-S1). Input seismic: angle gathers.
AVA Modeling and Analysis

An amplitude versus angle (AVA) modeling was built using the logs of the well Q16-FA-101-S1. The modeled angles range from 0 to 45°. This was compared with the original angle gather, which contains angles of incidence between 1 and 29°. The display polarity used was SEG. Figure 5.54 displays these angle gathers at shallower depths. It is observed higher similarities between the modeled gather and the original one. On the other hand, Figure 5.55 illustrates the same comparison at larger depths. The quality of the real angle gathers diminished at larger depths. One of the reasons of the lower quality could be the deviation of this well at larger depths. Moreover, this could also be related with the processing of the gathers, when the NMO corrections are applied and a stretching effect is produced. In consequence, it is difficult to study the changes in amplitude at different angles at Bunter reservoir. The modeled gather shows larger negative amplitudes at larger angles within the Bunter reservoir, which can be related with the presence of gas. While the original gather presents unreliable amplitudes at larger angles. The way that the amplitude varies with the angle at the modeled gather can be observed in the Figure 5.56. Two events were tracked within the Bunter reservoir; both have negative amplitudes and they become more negative at larger angles, after approximately 25°. This is characteristic of sandstone filled with gas fluid and can be classified as class 3 sandstones, with negative intercept and gradient (Castagna et al., 1993 and Sen, 2006). This effect cannot be seen in the real gathers because reliable amplitudes can only be observed until approximately 21°.

Figure 5.54 Comparison between a synthetic angle gather (0-45°) built with the logs of the well Q16-FA-101-S1 and the original angle gather (1-29°) at shallower depths. (SEG Polarity display).
Figure 5.55 Comparison between a synthetic angle gather (0-45°) built with the logs of the well Q16-FA-101-S1 and the original angle gather (1-29°) at larger depths. (SEG Polarity display).

Figure 5.56 AVA analysis of a modeled angle gather (0-45°) built with the logs of the well Q16-FA-101-S1. (SEG Polarity display).
Low Frequency Models

Initial low frequency model of acoustic impedance, shear impedance and bulk density were built using the well-logs, horizons interpreted and RMS velocities. These three models are illustrated through composite lines in the Figures 5.57, 5.58 and 5.59. Original well-logs are represented by the rectangles boxes. The low frequency content from 0 to 10Hz is coming from the well-logs. The lateral changes in the geometry are given by the interpreted horizons.
An inversion analysis was performed at all the well locations using as input: the angle gathers, well-logs, horizons interpreted and the wavelet extracted from the well-logs. Figures 5.60 and 5.62 illustrate the entire inverted red traces of $Z_p$, $Z_s$ and $\rho$ obtained after run a pre-stack simultaneous inversion at wells Q16-03 and Q16-08 respectively. Original well-log traces as well as the original low frequency model logs are displayed. The synthetic angle gather generated is compared with the original one and the difference or error between them is calculated and also displayed. In general, while it is observed an acceptable matching between the original and synthetic log for $Z_p$ and $Z_s$, the inverted density log does not. Figures 5.61 and 5.63 show the inversion analysis at the target intervals Posidonia Shale and Bunter Reservoir. The match between the original well-logs and inverted traces is considered very well at Posidonia Shale interval. On the other hand, although the inverted trace follow the same trend of the original one at the Bunter interval, the absolute value is not reached.

Inversion Analysis
Figure 5.60 Inversion analysis at well Q16-03. Initial Low frequency model (black trace), original well-log (blue trace), inverted well-log (red trace).

Figure 5.61 Closer look at Posidonia Shale Formation interval at well Q16-03. Initial Low frequency model (black trace), original well-log (blue trace), inverted well-log (red trace).
Figure 5.62 Inversion analysis at well Q16-08. Initial Low frequency model (black trace), original well-log (blue trace), inverted well-log (red trace).

Figure 5.63 Closer look at Posidonia Shale Formation interval and Bunter Reservoir interval at well Q16-08. Initial Low frequency model (black trace), original well-log (blue trace), inverted well-log (red trace).
Another way of doing the quality control of the match between the inverted logs and the original ones is generating crossplots of this data. Figure 5.64 illustrates these crossplots: Zp inverted versus Zp original, Zs inverted versus Zs original and ρ inverted versus ρ original. The linear trends show a slope of 0.87, 0.94 and 0.84 respectively. Consequently, the inverted impedances and density traces (synthetic traces) at well locations are considered a representative approximation to the original well-log traces.

![Figure 5.64 Crossplots inverted logs versus original logs: Zp, Zs and ρ.](image)

After the inversion analysis, the pre-stack simultaneous inversion was performed in the angle gather volume. The final outputs obtained from this inversion were volumes of Zp, Zs and ρb.

Figures 5.65, 5.66 and 5.67 show composite lines of Zp, Zs and ρb that passes through the wells Q16-03, Q16-04, Q16-FA-101-S1, Q16-08, MSG-03 and MSV-01-S2. In general, it is observed a good match between the original well-logs of Zp, Zs and ρb and the modeled properties obtained from the pre-stack simultaneous inversion.

In conclusion, model-based post-stack inversion and simultaneous pre-stack inversion are considered reliable seismic inversion techniques by several reasons. Firstly, these processes use as input data low frequency models of acoustic impedance, shear impedance and bulk density that were built with well-log data. These well-logs could add the low frequency content that the provided seismic data does not possess. Therefore, the objective of the inversion is that the final models honour the well-log data. Secondly, the lateral interpolation between the well-logs is driven by the interpreted horizons. It is very important that the lateral geometry of the models is guided by the horizons since this study area is characterised by half graben features. In consequence, the output models have structural geological meaning. Thirdly, the inversion processes were hard constraint, which means that the output models cannot deviate significantly from the initial low frequency models. As a result, the estimation of properties between the wells is restricted to a lower and upper percentage of the average well-log properties. This creates more confidence regarding the
rock property values obtained from the inversion not only at the well locations but also between them. Lastly, the used wavelets were extracted from the well-logs after the well-seismic ties were performed. The extraction of a full wavelet involve the use of well-logs in order to determine the phase and amplitude of the wavelet by finding an operator in time domain that shapes the well-log reflectivity to the seismic composite trace. This extraction is very sensitive to the well-seismic tie, which was previously fine tuned manually. The wavelets used as inputs for the inversions are considered accurately estimated due to their symmetrical shape observed, although the side lobes are slightly different. These differences in the side lobes can be related to small errors in the well-seismic ties that introduce noise to the estimated wavelets. Ultimately, the constraints mentioned above make the output rock property models some kind of unique solution to the inversion problem, which is that different acoustic impedance models can generate synthetic seismic traces similar to the original ones.

Moreover, having the original CDP gathers pre-stack time migrated allowed to study the changes in amplitude with offset at Bunter reservoir using angle gathers, which were previously converted from CDP gathers through RMS velocities. Therefore, an analysis of amplitude versus angle (AVA) could be done. Nevertheless, even though the largest offset was of 3300 meters, the reliable amplitudes were observed until approximately between 2100 and 2300 meters at Bunter reservoir, which in angles is about between 19 to 21 degrees. The unreliable amplitudes present a decrease that does not look related with fluid content, but with the seismic data processing. The input gathers are NMO corrected. Applying NMO corrections generates a stretching effect in the traces. This effect is more pronounce in traces located at larger offsets. A mute is applied in order to get rid of the stretching effect, but that also can cause an impact in the amplitude values. It is believed that in this case, the amplitudes at larger offset in the Bunter reservoir are affected by the previous data processing of the gathers. On the other hand, a modeled angle gather was built using the acoustic impedance well-logs and a wavelet extracted from the well-logs after they were positioned in the right time. The modeled gather was built with angles that go from 0 to 45 degrees. At Bunter reservoir interval, the modeled angle gather shows larger negative amplitudes at larger offsets, which allow classifying this reservoir as class 3 sandstones typically filled with gas, with negative intercept and gradient. Nevertheless, the effect can be observed after the 20 degrees. Consequently, although the gather were not being influenced by the stretching effect, there might not be enough larger angles to see this AVA behaviour.
Figure 5.65 Zp composite line from Pre-stack simultaneous inversion (input: angle gathers).

Final acoustic impedance volume which honour the well-log data.
Figure 5.66 Zs composite line from Pre-stack simultaneous inversion (input: angle gathers).

Final shear impedance volume which honour the well-log data.
Figure 5.67 Density composite line from Pre-stack simultaneous inversion (input: angle gathers).

Final bulk density volume which honour the well-log data.
6. Results and Analysis

Other rock properties were calculated based on \( V_p, \) \( V_s \) and \( \rho_b \). These properties are: shear modulus, bulk modulus, young’s modulus, Poisson’s ratio, \( V_p/V_s \) ratio, first Lamé parameter \( \lambda \), \( \lambda*\rho \) and \( \mu*\rho \). Table 6.1 shows the equation used for these estimations.

<table>
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<tr>
<th>Rock Property</th>
<th>Equation</th>
<th>Units (SI)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-wave velocity</td>
<td>( V_p = \frac{Z_p}{\rho_b} )</td>
<td>m/s</td>
</tr>
<tr>
<td>S-wave velocity</td>
<td>( V_s = \frac{Z_s}{\rho_b} )</td>
<td>m/s</td>
</tr>
<tr>
<td>Bulk density</td>
<td>( \rho_b )</td>
<td>Kg/m³</td>
</tr>
<tr>
<td>Acoustic impedance (P-impedance)</td>
<td>( Z_p )</td>
<td>(m/s)*(Kg/m³)</td>
</tr>
<tr>
<td>Elastic impedance (S-impedance)</td>
<td>( Z_s )</td>
<td>(m/s)*(Kg/m³)</td>
</tr>
<tr>
<td>Shear modulus</td>
<td>( \mu = \frac{Z_s^2}{\rho_b} )</td>
<td>GPa</td>
</tr>
<tr>
<td>Bulk modulus</td>
<td>( K = \frac{Z_p^2}{\rho_b} - \frac{4\mu}{3} )</td>
<td>GPa</td>
</tr>
<tr>
<td>Young’s modulus</td>
<td>( E = \frac{9K\mu}{3K+\mu} )</td>
<td>GPa</td>
</tr>
<tr>
<td>Poisson’s ratio</td>
<td>( \nu = \frac{(1 - \frac{V_p^2}{V_s^2})}{(V_p^2-V_s^2)} )</td>
<td>unitless</td>
</tr>
<tr>
<td>( V_p/V_s ) ratio</td>
<td>( \frac{V_p}{V_s} )</td>
<td>unitless</td>
</tr>
<tr>
<td>Lamé’s first parameter</td>
<td>( \lambda = K - \frac{2\mu}{3} )</td>
<td>GPa</td>
</tr>
<tr>
<td>Lambda*Rho</td>
<td>( \lambda*\rho )</td>
<td>(GPa)**(Kg/m³)</td>
</tr>
<tr>
<td>Mu*Rho</td>
<td>( \mu*\rho )</td>
<td>(GPa)**(Kg/m³)</td>
</tr>
</tbody>
</table>

Table 6.1 Rock properties equations.

Crossplots of these properties were built in order to continue characterising the Posidonia Shale Formation and the Bunter reservoir.

Posidonia Shale Formation

Well-log data analysis through crossplots is very important in order to perform a reservoir characterisation. Moreover, seismic inversion results should honour these data. Initially, a crossplot of bulk density versus P-wave velocity was built at the interval of Posidonia Shale Formation using log information of 32 wells located in other blocks in the North Sea basin. The well-log information was collected from the public database.
Figure 6.1 shows this crossplot, where the magenta points belong to the well-logs situated within the study area and the blue ones are from other areas. In general, it is distinguished a regional trend, with bulk density varying approximately from 1.9 to 2.8 gr/cc and Vp changing from about 2100 to 4400 m/s. Vp versus density crossplot at Posidonia Shale interval can also be observed in the Appendix D (Figure D.1), where it can be noticed that this trend fits with the Gardner model applied to log and laboratory shale data (Mavko, 2009). Moreover, Figure 6.2 illustrates histograms with the regional variations of Vp and $\rho_b$ within the Posidonia Shale. A good distribution is noticed of the data. Higher values of density and velocity can be distinguished, although a bit scattered, at the study area compared to other locations. This might be because the Posidonia Shale is found deeper in this area. In the Figure 6.3 it is observed that the Posidonia Shale is between 2300 and 2800 meters in the Q16 block, while it is situated at shallower depths in other zones excepting in the F03 block. It is interpreted that velocity and density increase with depth due to compaction.

Figure 6.1 also illustrates a crossplot of $\rho_b$ versus Vp only using the well-logs located at the seismic area. Posidonia Shale Formation interval was plotted (red) together with the units found above and below it: Werkendam Formation (blue) and Aalburg Formation (green) intervals respectively. Posidonia Shale presents lower values of density and velocity than Werkendam and Aalburg Formations. In the former one, the density varies from about 2 to 2.65 gr/cc and the velocity from 2400 to 3400 m/s; mean while in the other formations the density changes from approximately 2.5 to 2.7 gr/cc and the velocity from 3300 to 4500 m/s. Therefore, the acoustic impedance, product of bulk density and the P-wave velocity, decreases at Posidonia Shale interval comparing to the Formations above and below. This can be observed in the Figure 6.4, where a well-log correlation of Zp was done employing the wells: P18-A-02, P18-02, Q16-03, Q16-04, Q16-FA-101-S1 and Q16-08. Furthermore, the thickness of the Posidonia Shale is no more than 40 meters as can be seen in this correlation.

The decrease in Vp and $\rho_b$ could be due to the fact that the Posidonia Shale is a bituminous rock, it has organic matter. Other reason might be the presence of hydrocarbons, which can be interpreted from the higher deep resistivity reading of well-logs at that interval. According to geological reports and gas-logs found in the public database, the Posidonia Shale resulted 4400ppm of methane (CH$_4$), 178ppm of ethane (C$_2$H$_6$), 446ppm of propane (C$_3$H$_8$), 133ppm of normal butane (n-C$_4$H$_{10}$) and 33ppm of isobutene (i-C$_4$H$_{10}$) at well P18-02. Well Q16-04 has 4216 of C$_1$H$_4$ and 235ppm of C$_2$H$_6$. At the well Q16-03 the values are 2600ppm of C$_1$H$_4$, 260ppm of C$_2$H$_6$ and 220ppm of C$_3$H$_8$. According to these documents, the vitrinite reflectance ($R_o$) is 0.55% at this well, which indicates that this source rock is immature but close to the onset of oil generation. So, no significant hydrocarbon generation has occurred locally from the Posidonia Shale Formation. The total organic content (TOC) at this well is 6.5%, which is considered high. With this information, the Posidonia Shale Formation could be classified as an oil shale instead of a gas shale at this particular location.
Posidonia Shale Formation presents larger Vp and $\rho_b$ within Q16-block than in other areas because it is located deeper.

Posidonia Shale Formation at Q16 block has lower Vp and $\rho_b$ than the Formations above (Werkendam) and below (Aalburg), might be related with the presence of organic matter and/or hydrocarbon.

Figure 6.1 Crossplot Bulk Density (gr/cc) versus P-wave velocity (m/s). a) Regional trend of Posidonia Shale Formation interval. b) Werkendam, Posidonia and Aalburg Formation intervals within seismic area.
Figure 6.2 Histograms of well-log data at Posidonia Shale interval within North Sea basin. a) Vp and b) ρb. The colours represent the different wells.

Figure 6.3 Depth location of the top Posidonia Shale Formation at different blocks of the North Sea basin.
As was mentioned above, the Figure 6.4 displays the GR and Zp of six wells at Posidonia Shale interval. Zp decreases at this interval likely due to the organic matter content and/or hydrocarbon presence. Nevertheless, the top and base of the Posidonia Shale have uncertainty because the feature of the logs changes at each well. These differences in GR might be consequence of the heterogeneities present within this shale. Its thickness varies from approximately 15 to 42 meters in the wells (Table 6.2).

![Figure 6.4 Gamma Ray and Acoustic impedance well-logs correlation at Posidonia Shale interval.](image)

<table>
<thead>
<tr>
<th>Well</th>
<th>Thickness (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P18-A-02</td>
<td>15</td>
</tr>
<tr>
<td>P18-02</td>
<td>13</td>
</tr>
<tr>
<td>Q16-03</td>
<td>32</td>
</tr>
<tr>
<td>Q16-04</td>
<td>42</td>
</tr>
<tr>
<td>Q16-05</td>
<td>23</td>
</tr>
<tr>
<td>Q16-FA-101-S1</td>
<td>34</td>
</tr>
<tr>
<td>Q16-08</td>
<td>22</td>
</tr>
</tbody>
</table>

Table 6.2 Posidonia Shale thickness at seven wells within seismic area.

The top of the Posidonia Shale Formation was picked from the full stack seismic data previously to the performing of the model based acoustic inversion. As was mentioned before, the top is characterised by a soft kick (blue, positive amplitude). Figure 6.5 illustrates a composite line that passes through the wells Q16-FA-101-S1 and Q16-08, showing the initial full stack seismic data with a calculated resolution of approximately 25ms in the target...
area. Below, it is observed the acoustic impedance result. Zp decreases at Posidonia Shale interval. This also can be observed at the original Zp well-logs represented by the rectangular boxes. The base of the Posidonia Shale can be well recognised from the inversion, where the values decrease from about 8000 to 14000 (m/s)*(gr/cc). Reflection coefficients were obtained taking the first derivative of the acoustic impedance volume. The estimated resolution was approximately of 16ms at the target area.

Figure 6.5 Interpretation of top and base of Posidonia Shale Fm in a composite line. a) Full-stack seismic, b) P-impedance and c) Reflection coefficients (product of the first derivative of Zp).
After picking the base of the Posidonia Shale, a TWT map was generated. This base can be found between 2350 and 1750 ms of depth (Figure 6.6). The deeper places are located at the north-east and the shallower areas are placed close to the wells Q16-03 and Q16-04. But in general, the predominant depths are between 2000 and 2200 ms. Moreover, an isochron thickness map of this unit was built. The thickness can vary from approximately 10 to 42 ms. Larger thicknesses are observed at the north and west and smaller ones at the south and east at the mapped horizon. The average thickness is between 30 and 40 ms. Thicknesses less than 16 ms might be interfered with the resolution.

Figure 6.6 a) Base of the Posidonia Shale Fm map in TWT. b) Isochron thickness map of Posidonia Shale Fm.
Several properties were calculated at well locations based on gamma ray, P-wave velocity, bulk density, neutron porosity and deep resistivity. These properties are: volume of shale, S-wave velocity, acoustic impedance, shear impedance, effective porosity and water saturation. The Posidonia Shale Formation is characterised by a high GR and therefore a high Vsh; low Vp, Vs and ρb that give low Zp and Zs; low φeff, high resistivity due to hydrocarbon presence and therefore low Sw. Examples of these well-logs can be observed in Figure 6.7.

A number of crossplots were generated using the wells P18-A-02, P18-02, Q16-03, Q16-04, Q16-FA-101-S1 and Q16-08 in order to analysis the rock properties within the Posidonia Shale Formation. Figures 6.8 displays a crossplot of Vs versus Vp. A lineal trend is observed, where Vp varies from approximately 2300 to 4300 m/s and Vs from 1000 to 2100 m/s, which fits with rock-physics models built by Han, Marcote-Rios and Castagna (Mavko, 2009). This crossplot can be observed together with the rock-physics models in the Figures.
D.2 and D.3 of the Appendix D. This trend was coloured with Vsh, Sw and $\phi_{\text{eff}}$ respectively. Vsh and Sw decreases and $\phi_{\text{eff}}$ increases at larger Vp and Vs. An expected similar behaviour be seen in the crossplot Zs versus Zp, where Zp varies from 5000 to 10800 m/s*gr/cc and Zs changes from 2000 to 6000 m/s*gr/cc (Figure 6.9).

The decrease in Vsh might imply more presence of quartz, feldspars and/or calcite minerals and less content of clay. Moreover, higher brittleness and thus a more frackable rock is associated to these minerals. It is consistent that the velocities increase with the present of harder mineral. The velocities increase from North to South. Lower velocities are observed at the wells Q16-03 and Q16-04, where Posidonia Shale is found shallower. In contrast, higher velocities are distinguished at the wells Q16-FA-101-S1 and Q16-08, where this Formation is located deeper. Therefore, it is also consistent that the velocities are higher when depth increases due to compaction. Additionally, deposits with lower Vsh are above from those with higher Vsh.

The decrease in Sw is an indication of hydrocarbon presence. Lower Sw at larger depths could be interpreted as more generation of hydrocarbon due to a more mature Posidonia Shale. It is highlighted that the depth increases from approximately 2400 to 2900 meters, which is 500 meters of difference. This can cause an increase in temperature and pressure that can make the Posidonia Shale more mature. In consequence, the kerogen can be transformed into hydrocarbons.

The estimated effective porosity is a property that has considerable uncertainty. It was calculated through the density and resistivity logs, assuming values of water density, hydrocarbon density, matrix density and formation water resistivity. No core data was available to calibrate the generated logs. Moreover, the Sw also has uncertainty because it was estimated through the density, resistivity and effective porosity logs previously calculated. Regarding to the crossplot, even though the densities at well Q16-03 are lower than the densities at well Q16-FA-101-S1 at Posidonia Shale interval, the resistivity is a bit higher in the latter well. That could be making the porosity higher at this well. However, it does not result intuitive to think that porosity increases with depth. Nevertheless, these higher porosities are observed also where there is assumed to be more presence of quartz and calcite minerals and maybe then these porosities are more related with the mineralogy composition than with the depth locations.
Figure 6.8 Crossplots at Posidonia Shale interval (wells: P18-A-02, P18-02, Q16-03, Q16-04, Q16-FA-101-S1 and Q16-08). Vs versus Vp coloured with: a) Vsh, b) Sw and c) $\phi_{eff}$.
Figure 6.9 Crossplots at Posidonia Shale interval (wells: P18-A-02, P18-02, Q16-03, Q16-04, Q16-FA-101-S1 and Q16-08). Zs versus Zp coloured with: a) Vsh, b) Sw and c) ϕ_eff.

- **Figure 6.9 a:**
  - Zs versus Zp has a linear trend at Posidonia Shale Formation.
  - More clay content.
  - Vsh decreases.
  - Higher brittleness.
  - More presence of quartz and carbonates.

- **Figure 6.9 b:**
  - Lower Sw presence.
  - Hydrocarbon presence.

- **Figure 6.9 c:**
  - At larger Zp and Zs, ϕ increases, Vsh decreases and Sw decreases.
  - Higher Porosity.

Zs versus Zp has a linear trend at Posidonia Shale Formation. More clay content leads to more presence of quartz and carbonates, resulting in higher brittleness. Lower Sw presence indicates oil or gas saturation. At larger Zp and Zs, porosity increases, while Vsh and Sw decrease.
Figure 6.10 shows a composite line of Zp, Zs and ρb resulted from the pre-stack simultaneous inversion that passes through the wells Q16-03, Q16-04, Q16-05, Q16-FA-101-S1 and Q16-8 at Posidonia Shale Formation interval. The well-logs are original Zp, Zs and ρb respectively represented by the rectangle boxes. It is observed that the inversion results honour the well data, meaning that Zp, Zs and ρb decrease at Posidonia Shale interval compared to the Formations above and below. Laterally, it is noticed that the values of these properties increase from North to South within the Posidonia Shale, which might be related with the deeper location of this formation as was discussed above.

Figure 6.11 illustrates a crossplot of bulk modulus versus shear modulus coloured with Vsh, Sw and φeff. Bulk modulus varies from about 9 to 25 GPa with some higher values until 39 GPa. Shear modulus changes from 2 to 11 GPa. Smaller values of Vsh and Sw and larger values of φeff are observed when K modulus decreases and µ modulus increases.

In general, shear modulus and Bulk modulus increases with depth due to compaction. On the other hand, shear modulus increases and bulk modulus decreases when the Formation presents lower values of Vsh and Sw and higher values of porosity. The increment in shear modulus might be associated to the mineralogy, where areas with more presence of ductile minerals like clay have lower shear modulus compared to areas with more presence of brittle minerals such as quartz and calcite. These make sense since the shear modulus is defined as the ratio of the shear stress to the shear strain (Mavko et al., 2009). It means that the deformation would be less in areas with more content of brittle minerals than in areas with more presence of ductile minerals. On the other hand, the decrease in bulk modulus could be related with the fluid content. This property is defined as the ratio of the hydrostatic stress to the volume strain (Mavko et al., 2009). In other words, bulk modulus is a measure of the resistance of the fluid to compression, and water presents more resistance to be compressed than oil and definitely more than gas. Therefore, this property is strongly sensitive to water saturations and then, it is consistent to have lower Sw associated to lower bulk modulus.
Figure 6.10 Pre-stack simultaneous inversion results at Posidonia Shale interval. Composite line: a) Zp, b) Zs and c) ρb.

Lower Zp at North
Lower Zs at North
Lower ρb at North
Higher Zp at South
Higher Zs at South
Higher ρb at South

Acoustic Impedance (Posidonia Shale Fm)

Shear Impedance (Posidonia Shale Fm)

Bulk Density (Posidonia Shale Fm)
Figure 6.11 Crossplots at Posidonia Shale interval (wells: P18-A-02, P18-02, Q16-03, Q16-04, Q16-FA-101-S1 and Q16-08). K modulus versus μ modulus coloured with: a) Vsh, b) Sw and c) $\phi_{\text{eff}}$.

At larger shear modulus and lower bulk modulus, $\phi$ increases, Vsh decreases and Sw decreases.
Poisson’s ratio was plotted against Young’s modulus at Posidonia Shale interval (Figure 6.12). Young’s modulus varies from 5 to 30 GPa and Poisson’s ratio from 0.22 to 0.47. Vsh and Sw decrease and $\phi_{\text{eff}}$ increases at larger values of Young’s modulus and lower values of Poisson’s ratio. Young’s modulus describes the resistance of a material to be deformed when it is submitted to compressive or tensile forces. Moreover, Young’s modulus is defined as the ration of the shear stress to the shear strain (Mavko et al., 2009). Therefore, it is logic to think that deposits with lower Vsh have higher Young’s modulus. Regarding the Poisson’s ratio, this is defined as the lateral strain divided by longitudinal strain. Deposits with higher Vsh have larger Poisson’s ratio because they present more anisotropy due to the large clay content than in areas with an increased amount of quartz and/or carbonates mineral. The ratio between lateral and longitudinal strains is smaller in brittle mineral than in soft ones. Furthermore, the relationship between Poisson’s ratio and Young’s modulus is important in order to find areas of higher brittleness and therefore easily to fracture. The brittleness increases in areas where the Poisson’s ration decreases and the Young’s modulus increases.

On the other hand, the crossplot $\mu*\rho$ versus $\lambda*\rho$ (Figure 6.13) at Posidonia Shale interval shows that Vsh and Sw decrease and $\phi_{\text{eff}}$ increases at larger $\mu*\rho$ and lower $\lambda*\rho$. Values of $\mu*\rho$ varies from approximately 4 to 28 GPa*gr/cc and $\lambda*\rho$ changes from 13 to 70 GPa*gr/cc. The first Lamé parameter is related to the shear modulus and bulk modulus and the shear modulus is also known as the second Lamé parameter. These parameters, together with the bulk density, also serve in the characterisation of rock and fluid within reservoirs. Areas with more frackable minerals, that also show more hydrocarbon presence and porosity, are above the zones with more clay content.

Points with lower Vsh and Sw and higher porosity present an increased $\mu*\rho$, while $\lambda*\rho$ tends to be scattered. The shear modulus, also known as the second Lamé parameter, combined with the density is a good lithology discriminator. Therefore, it is expected that areas of the Posidonia Shale with an increased composition of brittle minerals have larger shear modulus and density than areas that have more clay minerals. On the other hand, $\lambda*\rho$ is a good discriminator of pore fluid. Lambda or the first Lamé parameter depends on the bulk modulus and shear modulus. The bulk modulus suffers a dramatic decrease when the fluid changes from water to gas, while the shear modulus is almost not affected. Since $\lambda$ is proportional to the bulk modulus and shear modulus, it is expected that lambda and density decreases when the Sw is reduced. In this case, $\lambda*\rho$ tends to be scattered to low.

These rock properties were also calculated using the volumes of Zp, Zs and $\rho_b$ obtained from the pre-stack simultaneous inversion. In that way, volumes of Vp/Vs ratio, Poisson’s ratio, Young’s modulus, Shear modulus, Bulk modulus, $\mu*\rho$ and $\lambda*\rho$ could be analysed as well.

Figure 6.14 display a composite line from North to South that pass through the wells Q16-03, Q16-04, Q16-05, Q16-Fa-101-S1 and Q16-08, showing Poisson’s ratio, Young’s modulus and Vp/Vs ratio. The match between the well-logs and the volume properties is less accurate than the match between Zp and Zs. Values of Vp/Vs ratio varies from approximately 1.7 to 2, Poisson’s ratio changes from about 0.25 to 0.35 and Young’s modulus goes from 8
to 35 GPa. Laterally, the Young’s modulus increases to the south. Lower Vp/Vs ratio and Poisson’s ratio are observed at the areas surrounding the well Q16-05.

Composite lines of $\mu^*\rho$ and $\lambda^*\rho$ are shown in the Figure 6.12. In general low values are observed within the Posidonia Shale Formation, $\mu^*\rho$ varies from about 5 to 35 GPa and $\lambda^*\rho$ changes from 10 to 50 GPa. Laterally, the values increase to the south.

Several rock property maps of Posidonia Shale Formation were generated (Figures 6.16 and 6.17). It can be seen that $Z_p$ varies from 5000 to 11500 m/s*gr/cc, $Z_s$ changes from 2500 to 6000 m/s*gr/cc, $\rho_b$ goes from 1.75 to 2.65 gr/cc, $V_p$ are found between 2900 and 4500 m/s and $V_s$ varies from 1500 to 2400 m/s. Larger values of $Z_p$, $Z_s$, $\rho_b$, $V_p$ and $V_s$ are observed to the east. In general, velocities and density increase with depth. The pore space closes and the rock becomes more compacted. Therefore, these larger values might be related with the fact that the Posidonia Shale is found deeper in that area. On the other hand, lower values of $Z_p$, $Z_s$ and $\rho_b$, $V_p$ and $V_s$ are distinguished at the north. The ratio $V_p/V_s$ changes between 1.7 to 2 and the Poisson’s ratio goes from approximately 0.24 to 0.33. Both properties decrease to the west. Furthermore, the estimated bulk modulus is between 9 to 30 GPa, the shear modulus changes from 3 to 14 GPa, the Young’s modulus varies from 10 to 35 GPa, $\mu^*\rho$ is between 7.5 to 35 GPa *gr/cc and $\lambda^*\rho$ varies from 12 to 53 GPa *gr/cc. The modulus and the Lamé parameters are lower at the north and higher at the east.
Figure 6.12 Crossplots at Posidonia Shale interval (wells: P18-A-02, P18-02, Q16-03, Q16-04, Q16-FA-101-S1 and Q16-08). Poisson’s ratio versus E modulus coloured with: a) Vsh, b) Sw and c) $\phi_{eff}$.

At larger Young’s modulus and lower Poisson’s ratio, $\phi$ increases, Vsh decreases and Sw decreases.

More presence of quartz and calcite Higher brittleness

Lower Vsh

Lower Sw

Higher Porosity
Figure 6.13 Crossplots at Posidonia Shale interval (wells: P18-A-02, P18-02, Q16-03, Q16-04, Q16-FA-101-S1 and Q16-08). $\mu^*\rho$ versus $\lambda^*\rho$ coloured with: a) Vsh, b) Sw and c) $\theta_{eff}$. 

At larger $\mu^*\rho$ and lower $\lambda^*\rho$, $\theta$ increases, Vsh decreases and Sw decreases.
Figure 6.14 Composite line of rock properties calculated from Zp, Zs and ρb volumes at Posidonia Shale interval. a) Vp/Vs ratio, b) Poisson’s ratio and c) Young’s modulus.
A brittleness index was estimated using the Poisson’s ratio and the Young’s modulus with these formulas (Perez, 2013):

\[
E_{brittleness} = \frac{E - E_{\text{min}}}{E_{\text{max}} - E_{\text{min}}} \quad 1)
\]

\[
\nu_{brittleness} = \frac{\nu - \nu_{\text{max}}}{\nu_{\text{min}} - \nu_{\text{max}}} \quad 2)
\]

\[
\text{Brittleness}_{\text{average}} = \frac{(E_{\text{brittleness}} + \nu_{\text{brittleness}})}{2} \quad 3)
\]

Where \( E_{\text{min}} \) = 5 GPa, \( E_{\text{max}} \) = 27 GPa, \( \nu_{\text{min}} \) = 0.24 and \( \nu_{\text{max}} \) = 0.45. Figure 6.18 shows a composite line that passes through the wells Q16-03, Q16-04, Q16-05, Q16-FA-101-S1 and Q16-08, and also a crossline that passes through the well Q16-03 of the estimated brittleness index. This varies from 0.4 to 1, being more brittle 1 and less brittle 0. As a result, higher brittleness, and therefore more fractureable areas, are distinguished at South within Posidonia Shale interval. On the other hand, lower brittleness or more ductile zones are observed at the North. Furthermore, this also can be seen in the map of the Figure 6.19. Lower fractureable zones are located at the north close to the wells Q16-03 and Q16-04 which have more clay minerals. Higher fractureable areas are situated at the south nearby the well Q16-FA-101-S1, where the Posidonia Shale Formation possess more brittle minerals like quartz or carbonates that are easily to fracture than ductile ones such as clay.
Figure 6.16 Rock properties maps (minimum amplitude attribute) at Posidonia Shale Formation interval. a) Acoustic impedance. b) Shear impedance. c) Bulk density. d) P-wave velocity. e) S-wave velocity. f) Vp/Vs ratio.
Figure 6.17 Rock properties maps (minimum amplitude attribute) at Posidonia Shale Formation interval. a) Shear modulus. b) Bulk modulus. c) Lambda*Rho. d) Poisson’s ratio. e) Young’s modulus. f) Mu*Rho.
Figure 6.18 Estimated brittleness index. a) Composite line that pass through the wells Q16-03, Q16-04, Q16-05, Q16-FA-101-S1 and Q16-08. See Figure 6.14 for location. b) Crossline 5703 that pass through the well Q16-03. See Figure 6.19 for location.

Figure 6.19 Estimated brittleness index map.
Figure 6.20 illustrates a comparison of different important maps of the Posidonia Shale Formation interval. The brittleness index, calculated through the Poisson’s ratio and Young’s modulus, is not considered related with the location in depths of the Posidonia Shale. This observation is illustrated through the comparison of the structural map and the brittleness index map of the Posidonia Shale. Deeper and shallower zones can present different brittleness index. Therefore, the brittleness index is related with the mineralogy. Moreover, larger brittleness index are related with more frackable areas, thus a frackability map was generated where the light red areas are 70% more frackable than the dark green areas. The area enclosed in the light green oval is considered a sweet spot in order to make hydraulic fracturing because in this zone the Posidonia Shale Formation possess a large extension, it is thicker and it is more brittle and hence more frackable.

**Figure 6.20** Comparison of different maps at Posidonia Shale interval in order to find sweet spots to do hydraulic fracturing. a) Structural map of the Posidonia Shale base, b) Brittleness index map, c) Isochron thickness map and d) Frackability map.
**Bunter Reservoir**

The Bunter reservoir consists of the sandstone units Hardegsen Formation, Detfurth Formation and Volpriehausen Formation. Some shale layers are intercalated in these sandstones units. Above and below this Bunter reservoir are found the shale units Solling Formation and Rogenstein Member respectively. Figure 6.21 shows a crossplot of bulk density versus P-wave velocity at Bunter reservoir interval using information of 32 wells located in the North Sea basin. In general, the density varies from 2 to 2.8 gr/cc and the velocity from 3200 to 6000 m/s. The magenta points are log information from the wells located within the study area. It is observed lower values of density compared to other areas, until approximately 2.65 gr/cc. This lower density is assumed to be associated with the presence of gas-bearing sandstones.

![Crossplot Bulk Density versus P-wave velocity](image)

**Figure 6.21 Crossplot Bulk Density versus P-wave velocity.**

- **a)** Regional trend of Bunter reservoir interval.
- **b)** Bunter reservoir and shales above and below within seismic area.

Sandstones of the Bunter reservoir at Q16 block has lower Vp than the shales above (Solling Fm) and below (Rogenstein Mb). The $\rho_b$ is also lower, but with the increment of depth, the densities of the sandstones located at the base are similar to the bounded shales.
The same figure shows another graph of density versus Vp with the information of the wells situated within the 3D survey area, including the Bunter reservoir coloured with yellow and the shales units above and below the reservoir coloured with gray. There is a clear distinction between the reservoir and the formations that bound it. It is noticed that the shale units present density values between 2.65 and 2.75 gr/cc, while the formations from the Bunter reservoir shows values from approximately between 2.25 and 2.65 gr/cc. Vp varies from 4300 to 5600 m/s at shale intervals and in Bunter reservoir changes from 3500 to 5600 m/s. Moreover, there is a characteristic lineal trend within the Bunter reservoir, where velocity and density increase with depth. In other words, the sandstones are found below the shales in the crossplot, but when depth increases, the density and velocity values of the sandstones of the Volpriehausen Formation and shales of the Rogenstein Member slightly overlap. The Figure D.4 in the Appendix D shows also the crossplot Vp versus density at Bunter reservoir interval. It is noticed that this trend fits the rock-physics model of Gardner applied to log and laboratory sandstone data (Mavko, 2009).

A more detail variation of Vp and $\rho_b$ at Bunter reservoir within North Sea basin can be observed in the histograms of the Figure 6.22. A better distribution is distinguished in the Vp histogram than in the density one. Moreover, the top of the Bunter reservoir is found between 2500 and 3500 meters of depth at wells located within the seismic area. This top is situated deeper at offshore wells than at onshore ones (Figure 6.23).

A correlation of the logs GR and Zp was done using the wells P18-A-02, P18-02, Q16-04, Q16-FA-101-S1, Q16-08, MSG-01, MSG-02 and MSG-03 at the Bunter reservoir interval (Figure 6.24). This interval is well characterised by its lower values of GR characteristic of sandstones from the top of Hardegsen Formation to the base of the Volpriehausen Formation. In fact, the top and base are very sharp. The Solling and Rogenstein Formations present much higher GR, which is expected from shales. On the other hand, the acoustic impedance suddenly decreases from the Solling Formation to the Hardegsen Formation. Then, Zp starts increasing again. It is hard to recognise the base of the Bunter reservoir or, in other words, the base of the Volpriehausen Formation because its acoustic impedance is similar to the Rogenstein Member found below. In general, the thickness of the Bunter reservoir at well locations is approximately 200 meters, where the Hardegsen, Detfurth and Volpriehausen Formations show average thicknesses of approximately 30, 60 and 100 meters respectively.

Analysing the results of the acoustic inversion, it is noticed that the tops of the Muschelkalk, Hardegsen and Volpriehausen Formations can be recognised. This can be seen in the Figure 6.25. A composited line that passes through the well Q16-08 at Bunter reservoir interval shows theses differences in acoustic impedances. Hardegsen and Detfurth interval have low Zp, while Volpriehausen interval has higher acoustic impedance. The acoustic impedance in the Rogenstein Member is similar to the acoustic impedance of the Volpriehausen Formation. This makes that the base of the Bunter reservoir cannot be recognised in the acoustic impedance property.

It is interpreted that the shales above and below the Bunter reservoir present higher densities due to their anhydritic mineral content. Moreover, the fact that the sandstones of the Bunter reservoir show sometimes larger densities than 2.65 gr/cc, which is the matrix density of a sandstone, might be because of the presence of dolomitic cement within the pore space. These sandstones are well sorted eolian and fluvial deposits that can be highly cemented by quartz and dolomitic cements that make density and velocity increase.
Figure 6.22 Histograms of well-log data at Bunter reservoir interval within North Sea basin. a) Vp and b) ρ_b.

Figure 6.23 Depth location of the top Bunter reservoir at different blocks of the North Sea Basin.
Figure 6.24 Gamma Ray and acoustic impedance well-logs correlation at Bunter reservoir interval.
Figure 6.25 Composite line at Bunter reservoir interval: a) Original full-stack seismic and b) Acoustic impedance.
A trend can be observed when the acoustic impedance is plotted against the effective porosity within the Bunter reservoir interval. Figure 6.26 shows these crossplots, where $Z_p$ decreases when $\phi_{\text{eff}}$ increases. This is consistent because at larger porosities, the density and $V_p$ decreases. The values of the effective porosity calculated vary between 2 and 24% and the acoustic impedance changes from 15000 to 7000 (m/s)*(gr/cc). Moreover, these crossplots were coloured with the properties of: $V_{\text{sh}}$, $S_w$ and $V_p/V_s$ ratio. It is noticed that lower values of $V_{\text{sh}}$ or cleaner sandstones are found in the upper part of the crossplot, with higher $Z_p$. The same behaviour is observed with the $S_w$ and $V_p/V_s$ ratio, which lower values are found in the upper part. Therefore, there is a higher presence of hydrocarbon in this area.

A volume of effective porosity was estimated using the estimated trend of the Figure 6.27. Other authors like Dvorkin and Alkhater (2004) estimated porosity volumes from relationships found between acoustic impedance and porosity from well-logs. Moreover, the Figure D.6 of the Appendix D shows a crossplot of $V_p$ versus porosity at the Bunter reservoir interval, where the trend fits with the rock-physic model of Wyllie (Mavko, 2009). Larger porosities are observed within the Hardegsen and Detfurth Formations and lower porosities are distinguished in the Volpriehausen Formation. Figure 6.28 shows a composite line of effective porosity that passes through the wells Q16-FA-101-S1 and Q16-08. In the upper part of the Bunter reservoir, the porosities are higher, between 15 and 10%, meanwhile the lower part presents porosities of less than 10%. Larger porosities at the upper part of Bunter reservoir maybe due to less compaction than in the lower zone, or perhaps Hardegsen and Detfurth Formations are less cemented than the Volprijehausen Formation. On the other hand, these larger porosities might be related to diagenetic processes. Arkosic sandstones consist of feldspars minerals that could be diluted creating secondary porosity.

Two maps of effective porosity were generated. Figure 6.29 illustrates the distribution of effective porosity within the upper part of the Bunter reservoir, which includes the Hardegsen and Detfurth Formations. Larger porosity values between 15 and 20% are observed close to the well Q16-03 at the north, at the proximities of the well Q16-05 in the middle and at the south where offshore wells are located. Lower values of porosity between 5 and 10% are noticed in the vicinity of the well Q16-08 at east. On the other hand, Figure 6.30 shows an effective porosity distribution map of the lower part of the Bunter reservoir, which consists of the Volprijehausen Formation. The porosities are lower compared to the upper part of the reservoir, varying between approximately 5 to 15%. Larger values between 10 to 15% are distinguished at the north, middle and south. While lower values of less than 10% can be seen in the proximities of the wells Q16-04 and Q16-08.
Zp decreases when effective porosity increases.

Vsh decreases, cleaner sandstones

Sw decreases, hydrocarbon presence

Vp/Vs ratio decreases, hydrocarbon presence

Figure 6.26 Crossplots at Bunter reservoir interval (wells: P18-A-02, P18-02, Q16-FA-101-S1, Q16-08, MSG-01 and MSG-02). Zp versus $\phi_{\text{eff}}$ coloured with: a) Vsh, b) Sw and c) Vp/Vs ratio.
Figure 6.27 Crossplot Porosity versus Zp coloured with density at Bunter reservoir interval. (wells: P18-A-02, P18-02, Q16-FA-101-S1, Q16-08, MSG-01 and MSG-02).

Figure 6.28 Composite line of calculated effective porosity that passes through wells Q16-FA-101-S1 and Q16-08.
Figure 6.29 Effective porosity map: Hardegsen and Detfurth Formation intervals. Larger porosities in Hardegsen and Detfurth Formations.

Figure 6.30 Effective porosity map: Volpriehausen Formation interval. Lower porosities in the Volpriehausen Formation.
S-wave velocity logs were calculated previously at each well using Xu-White model. Figure 6.31 shows these Vs calculated together with other rock properties: GR, Vsh, Vp, Zp, Zs, \( \rho_b \), NPHI (neutron-porosity), \( \phi_{ef} \), deep resistivity and Sw at Bunter reservoir interval within wells Q16-FA-101-S1 and P18-02. The gas effect can be observed through the entire reservoir when both, bulk density and neutron porosity logs, decrease. Larger effect is noticed in the upper zones than in the lower areas of the reservoir.

Figure 6.31 Well-logs at Bunter reservoir interval: GR, Vsh, Vs, Vp, Zp, Zs, \( \rho_b \), NPHI, \( \phi_{ef} \), deep resistivity and Sw. a) Well Q16-FA-101-S1 and b) Well P18-02.

Several crossplots were generated in order to analyse different rock properties and fluid content. Figure 6.32 displays the crossplot Vs versus Vp at Bunter reservoir interval. A clear lineal trend is observed where both velocities increase with depth. These increments are associated to compaction of the rock due to lithostatic pressure. Vp varies from approximately 3300 to 5700 m/s, while Vs changes between 2200 and 3800 m/s. The same crossplot can be observed in the Figure D.5 of the Appendix D, where the trend fits with the
rock-physics model built by Han and Castagna (Mavko, 2009). This trend was coloured with $V_{sh}$, $S_W$ and $\phi_{eff}$ respectively. Cleaner sandstones with lower $S_W$ are found in the upper part of the crossplots. On the other hands, larger porosities are noticed at lower $V_p$ and $V_s$.

The increment in $V_s$, through sandstones that have lower $S_W$, is because the bulk density decreases in presence of gas while the shear modulus remains almost constant. The little changes in the shear modulus is due to the fact that the shear deformation generally does not produce alterations in the pore volume and different pore fluids regularly do not affect this modulus. In consequences, $V_s$ is expected to increase in the presence of gas because this property is proportional to the shear modulus and inversely proportional to the bulk density. On the other hand, porosity decreases at larger depths probably due to compaction. Nevertheless, lower water saturations are observed through the entire reservoir.

A similar crossplot was made between shear impedance and acoustic impedance (Figure 6.33). The values of $Z_p$ varies from approximately 7000 to 15000 (m/s)*(gr/cc) and $Z_s$ changes from 4400 to 10000 (m/s)*(gr/cc). This crossplot was also coloured with $V_{sh}$, $S_W$ and $\phi_{eff}$ and the same features are observed than in the above graph.

In both crossplots, Figures 6.32 and 6.33, the cleaner sandstones with more hydrocarbon presence are located above the deposits with more clay, which are more water saturated.

Composite line examples of $Z_p$, $Z_s$ and $\rho_b$ properties resulted from the pre-stack simultaneous inversion can be observed at the Figures 6.34 and 6.35. One composite line passes through the wells Q16-03, Q16-04, Q16-05, Q16-FA-101-S1 and Q16-08; and the other composite line goes across the wells Q16-FA-101-S1 and MSG-03. The original well-logs of the different properties are represented by the rectangular boxes. It is noticed that the inversion results honoured the well-log data. The top of the Bunter reservoir is well recognised by the suddenly decreasing of $Z_p$, $Z_s$ and $\rho_b$, as could be seen also in the well-logs. Two areas can be distinguished vertically within the Bunter reservoir, one shallower zone with lower $Z_p$, $Z_s$ and $\rho_b$ and a deeper area with higher $Z_p$, $Z_s$ and $\rho_b$. It is interpreted that Hardegsen and Detfurth Formations belong to the upper zone and the Volpriehausen Formation is the lower part. It is hard to recognise the base of the Bunter reservoir because these properties look similar. Laterally, lower impedances and densities are observed nearby the wells Q16-03 and Q16-05, but not well-data is available to confirm these results at this interval. Moreover, the shallower onshore well MSG-03 also shows lower lateral $Z_p$, $Z_s$ and $\rho_b$. On the other hand, larger impedances and densities are noticed close to the well Q16-08, where Bunter reservoir is located deeper. A major fault can be well recognised in the composite lines $Z_p$ and $Z_s$ of the Figure 6.35.

Regarding the values, $Z_p$ varies approximately from 7000 to 15500 (m/s)*(gr/cc), $Z_s$ changes from 5000 to 9900 (m/s)*(gr/cc) and $\rho_b$ goes from about 2 to 2.85 gr/cc.

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Figure 6.32 Crossplots at Bunter reservoir interval (wells: P18-A-02, P18-02, Q16-FA-101-S1, Q16-08, MSG-01 and MSG-02). $V_s$ versus $V_p$ coloured with: a) $V_{sh}$, b) $S_w$ and c) $\phi_{eff}$.

V$_{sh}$ decreases, cleaner sandstones

Linear trend $V_s$ versus $V_p$ at Bunter reservoir interval

$S_w$ decreases, hydrocarbon presence

At lower $V_p$ and $V_s$, $V_{sh}$ is low, $S_w$ is low and porosity is high.

Porosity increases
Bunter reservoir interval

**Figure 6.33 Crossplots at Bunter reservoir interval (wells: P18-A-02, P18-02, Q16-FA-101-S1, Q16-08, MSG-01 and MSG-02).** Zs versus Zp coloured with: a) Vsh, b) Sw and c) $\phi_{eff}$.

- **Figure a**: Linear trend Zs versus Zp at Bunter reservoir interval. Vsh decreases, cleaner sandstones.
- **Figure b**: Sw decreases, hydrocarbon presence.
- **Figure c**: Porosity increases. At lower Zp and Zs, Vsh is low, Sw is low and porosity is high.
Figure 6.34 Composite line at Bunter reservoir interval passing through the wells: Q16-04, Q16-FA-101-S1 and Q16-08. a) Zp, b) Zs and c) \( \rho_b \).
Figure 6.35 Composite line at Bunter reservoir interval passing through the wells: Q16-FA-101-S1 and MSG-03. a) Zp, b) Zs and c) $\rho_b$. 

Bunter reservoir has lower Zp, Zs and $\rho_b$ at its upper zone (Hardegsen and Detfurth Fms) and higher properties at its lower zone (Volpriehausen Fm).
Like in the Posidonia Shale Formation, several rock properties were estimated using the resulted volumes $Z_p$, $Z_s$ and $\rho_b$ from the pre-stack simultaneous inversion at the Bunter reservoir interval. These properties are: bulk modulus, shear modulus, Poisson’s ratio, Young’s modulus, $V_p/V_s$ ratio, $\mu \rho$ and $\lambda \rho$. The formulas employed can be found in the Table 6.1. These properties also were calculated at well locations using the original well-logs.

Figure 6.36 displays a crossplot of bulk modulus versus shear modulus at Bunter reservoir interval, which was made with the logs of the wells P18-A-02, P18-02, Q16-FA-101-S1, Q16-08, MSG-01 and MSG-02. $K$ modulus and $\mu$ modulus are directly proportional and increase with depth. These makes sense because these modulus are directly proportional to velocities and densities. Therefore, at larger depths the rock becomes more compacted and velocities and densities increase as well as its bulk modulus and shear modulus. $K$ modulus varies from approximately 10 to 50 GPa and $\mu$ modulus changes from about 10 to 35 GPa. The crossplot was coloured with $V_{sh}$, $S_w$ and effective porosity respectively. Cleaner sandstones with lower $V_{sh}$ and lower $S_w$ are found above the deposits with more clay minerals and less hydrocarbon saturated. Nevertheless, it is observed that deposits with higher effective porosities and large presence of hydrocarbons present lower values of shear modulus and bulk modulus, between 10 to 20GPa and 10 to 25GPa respectively. The shear modulus is acting as a good lithology discriminator and it makes sense that this property increases when the amount of quartz minerals is larger than clay minerals. Conversely, the bulk modulus is working as fluid discriminator, where sandstones with more hydrocarbon presence and more porosity have lower bulk modulus.

Figure 6.37 illustrates a crossplot of Poisson’s ratio versus Young’s modulus. This crossplot was coloured with $V_{sh}$, $S_w$ and effective porosity. The crossplot is a bit scattered, where the Young’s modulus varies from about 22 to 85 GPa and increases with depth. The Poisson’s ratio goes from less than 0.1 to 0.4 and it is approximately constant across the Bunter reservoir. Cleaner sandstones with higher hydrocarbon content are located below those with higher $V_{sh}$ and $S_w$. The cleaner sandstones as a more or less constant Poisson’s ratio of 0.1, which is a characteristic value of sandstones saturated with gas. Larger effective porosities are found in the deposits with lower Young’s modulus.

$\mu \rho$ versus $\lambda \rho$ crossplot can be seen in the Figure 6.38. These values varies from 20 to 100 GPa*gr/cc and from 2 to 100 GPa*gr/cc respectively. The values of $\lambda \rho$ are more scattered than the values of $\mu \rho$. In this case, the cleaner sandstones with lower $V_{sh}$ and $S_w$ are located above the ones with higher clay content and more water saturated. Furthermore, deposits with larger effective porosities and more hydrocarbon presence have low $\mu \rho$ between 20 and 60 GPa*gr/cc and low $\lambda \rho$ between 2 to 15 GPa*gr/cc. $\mu \rho$ is showing to be a good lithology discriminator and $\lambda \rho$ a good fluid discriminator.
Figure 6.36 Crossplots at Bunter reservoir interval (wells: P18-A-02, P18-02, Q16-FA-101-S1, Q16-08, MSG-01 and MSG-02). Shear modulus versus bulk modulus coloured with: a) Vsh, b) Sw and c) $\phi_{\text{eff}}$. 
Figure 6.37 Crossplots at Bunter reservoir interval (wells: P18-A-02, P18-02, Q16-FA-101-S1, Q16-08, MSG-01 and MSG-02). Poisson’s ratio versus Young’s modulus coloured with:

a) Vsh, b) Sw and c) $\phi_{eff}$.

At lower Poisson’s ratio and Young’s modulus, Vsh is low, Sw is low and porosity is high.
Figure 6.38 Crossplots at Bunter reservoir interval (wells: P18-A-02, P18-02, Q16-FA-101-S1, Q16-08, MSG-01 and MSG-02). Mu*Rho versus Lambda*Rho coloured with: a) Vsh, b) Sw and c) $\phi_{\text{eff}}$.

Vsh decreases, cleaner sandstones
Sw decreases, hydrocarbon presence
Porosity increases
At lower $\mu^*\rho$ and $\lambda^*\rho$, Vsh is low, Sw is low and porosity is high.
Two composite lines of Vp/Vs ratio, Poisson’s ratio and Young’s modulus are displayed in the Figures 6.39 and 6.40. One composite line goes across the wells Q16-03, Q16-04, Q16-05, Q16-FA-101-S1 and Q16-08. The other passes through the wells Q16-FA-101-S1 and MSG-03. The original well-log properties are represented by rectangular boxes. It is observed that the properties estimated from the inversion match the well-log data. Within the Bunter reservoir, Vp/Vs ratio varies from approximately 1.5 to 1.8, Poisson’s ratio goes from about 0.1 to 0.28 and Young’s modulus changes from approximately 25 to 65 GPa. It is noticed that the base of the Bunter reservoir is better recognised in properties like Vp/Vs ratio and Poisson’s ratio because the Volpriehausen Formation has lower values than the Rogenstein Member. Vertically, Poisson’s ratio and Vp/Vs ratio is constantly low at Bunter reservoir, but the Volpriehausen Formation present lower values between the well Q16-FA-101-S1 and Q16-08. The Young’s modulus is lower in the upper part of the reservoir and higher in the Volpriehausen Formation. In the Figure 6.40, it is distinguished that the Young’s modulus is higher at deeper locations offshore than at shallower areas onshore nearby the well MSG-03.

The same composite lines showing the properties $\mu^*\rho$ and $\lambda^*\rho$ are displayed in the Figure 6.41 and 6.42. These estimated properties, product of the inversion, honoured the well-log data. Moreover, the top and base of the Bunter reservoir are well recognised. Lower values of $\mu^*\rho$ and $\lambda^*\rho$ are observed in the upper zone of the Bunter reservoir where Hardegsen and Detfurth Formations are situated. Conversely, higher values of $\mu^*\rho$ and $\lambda^*\rho$ are distinguished in the lower area of the reservoir where the Volpriehausen Formation is located. The values of $\mu^*\rho$ and $\lambda^*\rho$ are found between 10 and 90 GPa*gr/cc and between 10 and 65 GPa*gr/cc respectively. Maps of the different properties were generated within the upper and lower intervals of the Bunter Formations. Figures from 6.43 to 6.46 show these maps of Zp, Zs, $\rho_b$, Vp, Vs, Vp/Vs ratio, Poisson’s ratio, E modulus, $\mu$ modulus, K modulus, $\mu^*\rho$ and $\lambda^*\rho$. The acoustic impedance, shear impedance and bulk density are lower nearby the wells Q16-03 at the North, Q16-05 in the middle and MSG-03 at the South. In general, the values vary from 7000 to 14500 (m/s)*(gr/cc), from 4500 to 8500 (m/s)*(gr/cc) and from 2 to 2.75 gr/cc respectively. Lower values of these properties are observed at the upper area of the Bunter Formation where the Hardegsen and Detfurth Formations are located, and higher values are distinguished in the lower zone where the Volpriehausen Formation is placed. Vp and Vs displayed the same characteristics mentioned above, changing from 3500 to 5100 m/s and from 2100 to 3000 m/s respectively. The Vp/Vs ratio is found between 1.5 and 1.8. At the upper zone of the reservoir, lower Vp/Vs ratios are found close to the wells P18-02, Q16-04 and Q16-FA-101-S1. On the other hand, lower values of Vp/Vs ratio at Volpriehausen Formation are found nearby the wells MSG-03, Q16-08 and Q16-FA-101-S1. Moreover, the Poisson’s ratio varies from about 0.14 to 0.30, where lower values are found at the well Q16-FA-101-S1 in the entire reservoir. At Volpriehausen Formation, the well Q16-08 also has lower values of Poisson’s ratio. Regarding to the Young’s modulus, shear modulus, bulk modulus, $\mu^*\rho$ and $\lambda^*\rho$, present lower values at wells Q16-03, Q16-05 and MSG-03. They change from 25 to 60 GPa, from 9 to 25 GPa, from 14 to 35 GPa, from 18 to 60 GPa*gr/cc and from 15 to 50 GPa*gr/cc respectively. Higher values are observed in the Volpriehausen.
Figure 6.39 Composite line at Bunter reservoir interval passing through the wells: Q16-04, Q16-FA-101-S1 and Q16-08. a) Vp/Vs ratio, b) Poisson’s ratio and c) Young’s modulus.
Figure 6.40 Composite line at Bunter reservoir interval passing through the wells: Q16-FA-101-S1 and MSG-03. a) Vp/Vs ratio, b) Poisson’s ratio and c) Young’s modulus.
Figure 6.41 Composite line at Bunter reservoir interval passing through the wells: Q16-04, Q16-FA-101-S1 and Q16-08. a) Mu*Rho and b) Lambda*Rho. For location see Figure 6.39.

Figure 6.42 Composite line at Bunter reservoir interval passing through the wells: Q16-FA-101-S1 and MSG-03. a) Mu*Rho and b) Lambda*Rho. For location see the Figure 6.40.
Figure 6.43 Rock property maps (arithmetic mean attribute) at Bunter reservoir interval. Hardegsen and Detfurth Formations: a) $Z_p$, b) $Z_s$ and c) $\rho_b$. Volpriehausen Formation: d) $Z_p$, e) $Z_s$ and f) $\rho_b$. 

- Lower $Z_p$ at the upper zone of the Bunter reservoir.
- Higher $Z_p$ at the lower zone of the Bunter reservoir.
- Lower $Z_s$ at the upper zone of the Bunter reservoir.
- Higher $Z_s$ at the lower zone of the Bunter reservoir.
- Lower $\rho_b$ at the upper zone of the Bunter reservoir.
- Higher $\rho_b$ at the lower zone of the Bunter reservoir.
Figure 6.44 Rock property maps (arithmetic mean attribute) at Bunter reservoir interval. Hardegsen and Detfurth Formations: a) Vp, b) Vs and c) Vp/Vs ratio. Volpriehausen Formation: d) Vp, e) Vs and f) Vp/Vs ratio.
Figure 6.45 Rock property maps (arithmetic mean attribute) at Bunter reservoir interval. Hardegsen and Detfurth Formations: a) Poisson’s ratio, b) Young’s modulus and c) Shear modulus. Volpriehausen Formation: d) Poisson’s ratio, e) Young’s modulus and f) Shear modulus.
Figure 6.46 Rock property maps (arithmetic mean attribute) at Bunter reservoir interval. Hardegsen and Detfurth Formations: a) Bulk modulus, b) Mu*ρ and c) Lambda*ρ. Volpriehausen Formation: d) Bulk modulus, e) Mu*ρ and f) Lambda*ρ.
7. Conclusions

The objective of this study was to perform a reservoir characterisation of the Posidonia Shale Formation and the Bunter reservoir, through seismic inversion techniques, in order to obtain several rock properties and analyse how their variations are related to changes in depth, lithology and fluid content. It was considered that the rock property volumes: acoustic impedance, elastic impedance and bulk density obtained from the model-based post-stack seismic inversion and from the pre-stack simultaneous seismic inversion were accurate models as they honour the well-log data, not only in the Posidonia and Bunter intervals, but also in the surrounding formations. Furthermore, these three output volumes allowed estimating other rock property volumes: shear modulus, bulk modulus, Young’s modulus, Vp/Vs ratio, Poisson’s ratio, lambda*rho and mu*rho. In consequence, all the analyses made using these volumes are considered valuables for locate interesting target areas that could be hydrocarbon-bearing.

Posidonia Shale Formation

- The seismic reflection of this Formation has a characteristic low frequency content that helped in the seismic interpretation of its top and base.

- The Posidonia Shale is faulted and eroded in the West of the study area. The faults have a NW-SE trend and the Formation is found between 2300 and 2800 meters.

- The rock properties volumes acoustic impedance, elastic impedance and bulk density obtained from the model-based and the pre-stack simultaneous inversion methods honoured the well-log data, which gives confidence in the derived rock property volumes.

- The compressional wave velocity, shear wave velocity and bulk density are lower at the Posidonia Shale Formation than at the bounded Werkendam and Aalburg Formations. This is because of the presence of organic matter and/or hydrocarbon.

- The output rock property volumes also distinguished the top and base of the Posidonia Shale Formation clearly. Its thickness varies from approximately 12 to 45ms in TWT, which in depths is approximately from 27 to 67 meters.

- The Posidonia Shale Formation can be followed easily laterally from the output rock property volumes, in particularly the acoustic impedance volume. This is an advantage when horizontal drilling needs to be performed.
• A brittleness index map was built from the Poisson’s ratio and Young’s modulus properties. A more brittle area was observed in the South of the mapped Posidonia Shale, which implicates that this area is easier to be fractured.

• The obtained brittleness index map is related to the mineralogy and not to the depth location of the Posidonia Shale.

• The western area of the mapped Posidonia Shale is selected as a sweet spot in order to make hydraulic fracturing due to its large lateral extent, larger thickness and higher brittleness.
Bunter reservoir

- Bunter reservoir is faulted and compartmentalised. The faults have a NW-SE trend and the reservoir is found between 2500 and 3500 meters in depth. The seismic resolution decreased with depth, which made it more difficult to interpretate.

- The Volpriehausen Formation has porosities of approximately 10%, which are lower than the porosities of the Detfurth and Hardegsen Formations that are between 15 and 20%. These differences are attributed to changes in porosity due to diagenetic processes. Secondary porosity was created in the upper zone, while the porosity of the lower zone was reduced by precipitation of quartz and dolomite cement in the pore space.

- The synthetic modeled gather allowed studying the variation of amplitudes at larger angles than was acquired in the available seismic data. It was observed that an increase in the negative amplitudes were observed at larger offsets, which classifies this reservoir as class 3 sandstones typically filled with gas, with negative intercept and gradient.

- The well-seismic ties were considered accurate enough. The rock property volumes obtained from the seismic inversion methods honoured the well-log data.

- Even though the Bunter reservoir consists of lithologically uniform massive stacked sandstones, the obtained rock property volumes allow distinguishing two zones within the target unit. An upper zone that consist of Hardegsen and Detfurth Formations and a lower zone that consists of the Volpriehausen Formation. The upper zone presents lower acoustic impedance, shear impedance and bulk density than the lower zone. These differences are attributed to changes in porosity. Larger porosities make these rock properties decrease. Moreover, it is believed that the entire Bunter reservoir is gas-bearing, but in the Volpriehausen Formation the gas is tighter. The gas presence in the Hardegsen and Detfurth Formations also makes decreases these rock properties.

- Vp/Vs ratio and Poisson’s ratio are good gas-fluid indicators. Both decreases at the Bunter reservoir, allowing to separate the sandstones filled with gas from the bounded shales Solling and Rogenstein Formations. Furthermore, these rock property volumes allowed mapping the top and base of the Bunter reservoir much better than in the original seismic reflectivity volume.
In a nutshell, the rock property volumes obtained from the seismic inversions gave plenty of information about the lithology and fluid within the formations. Moreover, sometimes these volumes can be more helpful in the mapping of important surfaces than the original seismic volumes. In the case of the Posidonia Shale Formation, Young’s modulus and Poisson’s ratio allowed estimating a brittleness index and hence identify areas of higher brittleness that are suitable for hydraulic fracturing. While in the case of the Bunter reservoir, Vp/Vs ratio and Poisson’s ratio enabled to identify areas that could be gas-bearing.
8. **Recommendations**

- Acquiring a 3D seismic with longer offsets would allow studying the amplitude variations with offsets in more detail, particularly at Bunter reservoir interval or even at deeper formations. It was observed in the modeled gathers at Bunter reservoir interval that there were amplitude variation at larger offsets/angles than was acquired in the original gathers.

- Reduce the residual NMO corrections at the zones of interests in order to have a better alignment of the events. This would enhance the stacking and also the AVO and/or AVA analysis would be more reliable.

- With the longer offsets and better NMO corrections in the CDP gathers data would allowed to study in more detail the variation between rock properties obtained from the pre-stack simultaneous inversion at different angle stacks.

- Acquiring shear wave velocity well-logs, especially at Posidonia Shale interval would reduce the uncertainty of the estimated rock properties.

- Core data would allow a better calibration of the well-log data. Especially an accurate mineralogy composition of the Posidonia Shale Formation could have allowed the estimation of better volumes of clays, quartz, calcite and other minerals.

- Not all the wells are drilled until the Bunter reservoir and those that penetrate this interval are very deviated. If it is possible, to drill a few extra vertical wells through the Bunter reservoir.

- It is still unsure if the Posidonia Shale Formation is an oil prone and/or gas prone in this area. More TOC data at well-locations would allow studying the relationship between the mineralogy and the TOC content and therefore limited better the sweet spot areas.
9. References


Appendix A: Initial well-log information

Figure A.1 Well-logs Q16-04.
Figure A.2 Well-logs Q16-05.
Figure A.3 Well-logs Q16-08.
Figure A.4 Well-logs P18-02.
Figure A.5 Well-logs MSG-01.
Figure A.6 Well-logs MSG-02.
Figure A.7 Well-logs MSG-03.
Figure A.8 Well-logs MSV-01-S2.
Appendix B: Well-Seismic Tie for Pre-Stack Inversion

Figure B.1 Well-seismic tie (Well Q16-04).

Figure B.2 Well-seismic tie (Well Q16-08).
Figure B.3 Well-seismic tie (Well Q16-05).

Figure B.5 Well-seismic tie (Well MSV-01-S2).
Figure B.6 Well-seismic tie (Well MSG-01).

Figure B.7 Well-seismic tie (Well MSG-02).
Figure B.8 Well-seismic tie (Well MSG-03).
Appendix C: Xu-White Model for Velocity Estimations

Xu-White model is a velocity model for clay-sand mixtures. Unlike standard porosity-velocity models, this one takes into consideration the scatter produced by clays when a relationship is established between porosity and P-wave transit times. Xu-White model makes a difference between the pore aspect ratios (pore geometry) of clays and sands. The former ones are much smaller than the latter ones because clays consist of fine sheet-like particles. Kuster and Toksöz, effective medium and Gassmann theories are the foundations of this model where two types of pores exist: those associated with sand grains ($\alpha_s$) and others associated with clays ($\alpha_c$), assuming that the geometry of both is significantly different. The final goal of Xu-White model is to predict P-wave and S-wave logs from other logs through large depth intervals where formations can vary from unconsolidated to consolidated sandstones and shales (Xu and White, 1995 and 1996).

Evaluation of sand-related and clay-related pore volumes

The total pore space of the mixture ($\phi$) is the sum of pore spaces related to sand grains ($\phi_s$) and those associated with clays ($\phi_c$):

$$\phi = \phi_s + \phi_c \hspace{1cm} (1)$$

$\phi_s$ and $\phi_c$ are assumed to be directly proportional to sand grain volume ($V_s$) and clay content or shale volume ($V_{sh}$):

$$\phi_s = V_s \frac{\phi}{1-\phi} \hspace{1cm} (2) \hspace{1cm} \phi_c = V_{sh} \frac{\phi}{1-\phi} \hspace{1cm} (3)$$

Where total effective porosity ($\phi$) can be estimated from density (or neutron) and resistivity logs. Moreover, calculations of $V_{sh}$ can be done using GR log and $V_s$ is:

$$V_s = 1 - \phi - V_{sh} \hspace{1cm} (4)$$

Time-average equations are employed to calculate P-wave and S-wave transit times of the mixture (shaly sands and sandy shales):

$$T^P_m = (1 - V'_{sh})T^P_g + V'_{sh}T^P_{sh} \hspace{1cm} (5)$$
\[ T_m^S = (1 - V'_{sh})T_g^S + V'_{sh}T_{sh}^S \] (6)

\[ \rho_m = (1 - V'_{sh})\rho_g + V'_{sh}\rho_{sh} \] (7)

Where \( T_m^P, T_m^S \) and \( \rho_m \) are, respectively, P-wave transit time, S-wave transit time and density of the mixture. \( T_g^S, T_{sh}^S \) and \( \rho_g \) are related to the sand grains. \( T_{sh}^P, T_{sh}^S \) and \( \rho_{sh} \) are associated to clay minerals. \( V'_{sh} \) is the shale volume normalized by the volume of solid matrix:

\[ V'_{sh} = \frac{V_{sh}}{1 - \phi} \] (8)

**Calculation of elastic moduli**

Transit times can be employed for calculate the elastic bulk \( (K_m) \) and shear moduli \( (\mu_m) \) of the mixture:

\[ K_m = \rho_m \left( \frac{1}{(T_m^P)^2} + \frac{4}{3(T_m^S)^2} \right) \] (9)

\[ \mu_m = \rho_m \left( \frac{1}{(T_m^P)^2} \right) \] (10)

Dry rock properties can be derived from the Kuster and Toksöz theory, which “give equations for evaluating the moduli of an elastic medium permeated with a dilute (\( \phi \ll \alpha \)) distribution of (non-interacting) ellipsoidal pores”:

\[ K_d = \frac{K_m + 4A\mu_m}{1 - 3A} \] (11)

\[ \mu_d = \mu_m \frac{1 + B(9K_m + 8\mu_m)}{1 - 6B(K_m + 2\mu_m)} \] (12)

Where:

\[ A = \frac{1}{3} \left( \frac{K'_{\alpha} - K_m}{3K_m + 4\mu_m} \right) \sum_{i=s,c} \theta_i T_{ii} \alpha_i \] (13)
 Bulk moduli of the dry frame, the mixture and the fluid are represented by $K_d$, $K_m$ and $K'$ respectively. It is the same for the shear moduli ($\mu_d$, $\mu_m$ and $\mu'$). $K'$ and $\mu'$ are assumed zero (empty pores) when the dry frame is being calculated. $T_{iij}$ and $T_{iiij}$ are related to the aspect ratio of the inclusions and the moduli and densities of the matrix and fluid enclosed:

\[
T_{iij} = \frac{3F_4}{F_2} \tag{15}
\]

\[
T_{iiij} = \frac{1}{3} T_{iij} = \frac{2}{F_3} + \frac{1}{F_4} + \frac{F_4F_5 + F_6F_7 - F_8F_9}{F_2F_4} \tag{16}
\]

Where:

\[
F_1 = 1 + D \left[ \frac{3}{2} (g + \varnothing) - R \left( \frac{3}{2} g + \frac{5}{2} \varnothing - \frac{4}{3} \right) \right] \tag{17}
\]

\[
F_2 = 1 + D \left[ 1 + \frac{3}{2} (g + \varnothing) - \frac{R}{2} (3g + 5\varnothing) \right] + H(3 - 4R) + \frac{D}{2} (D + 3B) (3 - 4R) [g + \varnothing - R(g - \varnothing + 2\varnothing^2)] \tag{18}
\]

\[
F_3 = 1 + \frac{D}{2} \left[ R(2 - \varnothing) + \frac{1 + \alpha^2}{\alpha^2} g(R - 1) \right] \tag{19}
\]

\[
F_4 = 1 + \frac{D}{4} [3\varnothing + g - R(g - \varnothing)] \tag{20}
\]

\[
F_5 = D \left[ R \left( g + \varnothing - \frac{4}{3} \right) - g \right] + H\varnothing(3 - 4R) \tag{21}
\]

\[
F_6 = 1 + D[1 + g - R(g + \varnothing)] + H(1 - \varnothing)(3 - 4R) \tag{22}
\]

\[
F_7 = 2 + \frac{D}{4} \left[ 9\varnothing + 3g - R(5\varnothing + 3g) \right] + H\varnothing(3 - 4R) \tag{23}
\]

\[
F_8 = D \left[ 1 - 2R + \frac{g}{2} (R - 1) + \frac{\varnothing}{2} (5R - 3) \right] + H(1 - \varnothing)(3 - 4R) \tag{24}
\]

\[
F_9 = D[g(R - 1) - R\varnothing] + H\varnothing(3 - 4R) \tag{25}
\]
Where \( K \) and \( \mu \) are the bulk and shear moduli respectively of the solid in which the pores are embedded, and \( K' \) and \( \mu' \) are the bulk and shear moduli of the inclusions.

\[
\phi = \frac{\alpha}{(1-\alpha^2)^\frac{3}{2}} \left( \cos^{-1} \alpha - \alpha(1 - \alpha^{1/2}) \right) \quad (30)
\]

Gassmann equations

In order to simulate the effect of fluid relaxation, Gassman model can be used, formulating the compressional velocity \( (u_p) \) as:

\[
u_p = \left\{ \frac{1}{\rho_b} \left[ K_d + \frac{4}{3} \mu_d + \frac{(1-C_m)^2}{c_m(1-\alpha) + C_f(1-\alpha^n)c_f} \right] \right\}^{1/2} \quad (31)
\]

Where \( K_d \) and \( \mu_d \) are the bulk and shear moduli of the dry rock, \( \rho_b \) is the bulk density and \( \rho_f \) is the density of the fluid. \( C_m, C_f \) and \( C_d \) are the compressibilities of the matrix, fluid and dry rock frame respectively:

\[
\rho_b = \rho_m(1-\phi) + \rho_f \phi \quad (32) \quad C_m = \frac{1}{K_m} \quad (33) \quad C_f = \frac{1}{K_f} \quad (34) \quad C_d = \frac{1}{K_d} \quad (35)
\]

\( u_s \) (shear-wave velocity) of a rock which pore space is filled by non-viscous fluid is given by:

\[
u_s = \left\{ \frac{\mu_d}{\rho_b} \right\}^{1/2} \quad (36)
\]
Appendix D: Crossplot Models

Figure D.1 Crossplot $V_P$ versus $\rho_b$ at Posidonia Shale Formation interval. This fits with the Gardner model applied to log and laboratory shale data (Mavko, 2009).

Figure D.2 Crossplot $V_P$ versus $V_S$ at Posidonia Shale Formation interval. This fits with Han and Castagna models applied to laboratory $V_P$-$V_S$ data for water-saturated shales (Mavko, 2009).
Figure D.3 Crossplot Vs versus Vp at Posidonia Shale Formation interval. This fits with Marcote-Rios model applied to Vp versus Vs data for different coals (Mavko, 2009).

Figure D.4 Crossplot Vp versus ρb at Bunter reservoir interval. This fits with the Gardner model applied to log and laboratory sandstone data (Mavko, 2009).
Figure D.5 Crossplot $V_p$ versus $V_s$ at Bunter reservoir interval. This fits to Han and Castagna models applied to laboratory $V_p$-$V_s$ data for water-saturated sandstones (Mavko, 2009).

Figure D.6 Crossplot $V_p$ versus porosity at Bunter reservoir interval. This fits with the Wyllie model (Mavko, 2009).