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# Fluid Substitution Analysis Of The Heimdal Formation Reservoir, Northern North Sea: Implications For Seismic Reservoir Characterisation And Hydrocarbon Prediction

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***Abstract***
*Fluid substitution modeling is an essential rock physics technique for evaluating the seismic response of reservoirs under varying pore-fluid conditions. This study investigates the influence of fluid substitution on the elastic properties of the Heimdall Formation reservoir in the Northern North Sea using Gassmann's fluid substitution theory. Well log data comprising compressional-wave velocity (Vp), shear-wave velocity (Vs), density, porosity, and shale volume were utilized to model the replacement of in-situ hydrocarbon with brine. From wire line logs analysis a decrease in porosity and clay content with increase in seismic properties (Vp, Vs and density) was observed, while cementation increases with increasing seismic properties. Well 2 was fluid substituted from brine to oil and from brine to gas for a measured depth of 2154-2204m. The fluid substitution result indicates the most sensitive seismic attribute to fluid changes is the P-wave velocity, which varies from 2588-2100 m/s when brine is substituted with gas. Results indicate that hydrocarbon saturation significantly reduces acoustic impedance and increases Vp/Vs sensitivity relative to brine-saturated conditions. Fluid substitution produced noticeable changes in reflection coefficients and seismic amplitudes, demonstrating the effectiveness of rock physics modeling in predicting fluid-related seismic signatures. The findings highlight the potential of fluid substitution modeling for improving reservoir characterization, hydrocarbon detection, and uncertainty reduction during field development within the Heimdall Formation and analogous North Sea reservoirs.*

***Keywords:*** *Fluid substitution, Heimdall Formation, Northern North Sea, Gassmann equation, rock physics, reservoir characterization.*

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## I. Introduction

The accurate characterization of subsurface reservoirs remains a major objective in hydrocarbon exploration and production. Among the various factors controlling seismic responses, pore-fluid composition plays a dominant role because variations in fluid type alter the elastic properties of reservoir rocks. Rock physics provides the theoretical framework that links reservoir properties with seismic observations, thereby allowing geoscientists to predict fluid effects before drilling (Mavko et al., 2005).

The Heimdall Formation, a Paleocene deep-marine sandstone reservoir within the Northern North Sea, is one of the most productive hydrocarbon-bearing formations in the region. The formation consists predominantly of submarine fan sandstones interbedded with marine shales and exhibits excellent reservoir quality due to high porosity and permeability. However, distinguishing hydrocarbon-bearing intervals from brine-filled sands remains challenging because lithological similarities often mask fluid effects. Fluid substitution techniques based on Gassmann's equations (Gassmann, 1951) have become indispensable tools for evaluating the impact of changing pore fluids on seismic velocities and density. These techniques facilitate feasibility studies for seismic inversion, amplitude variation with offset (AVO) interpretation, time-lapse (4D) seismic monitoring, and reservoir management.

This study applies Gassmann fluid substitution to investigate the seismic response of the Heimdall Formation under different fluid scenarios. The primary objectives are to: Evaluate the influence of fluid replacement on elastic properties. Quantify changes in acoustic and shear impedance. Assess the sensitivity of seismic attributes to fluid saturation.

## II. Geological Setting

The Northern North Sea is one of the world's most extensively explored petroleum provinces. Hydrocarbon accumulations are hosted within Jurassic, Cretaceous, and Paleocene sedimentary successions deposited under varying tectonic regimes associated with the opening of the North Atlantic (Cayley, 1987; Avseth et al., 2005).

The Heimdall Formation belongs to the Paleocene Rogaland Group and was deposited in deep-marine submarine fan environments (Fig. 1). The formation consists mainly of fine- to coarse-grained turbiditic sandstones interbedded with mudstones. Reservoir quality is generally excellent, with porosity ranging between 20% and 35% and permeability exceeding several Darcy in clean sandstone intervals (Knox and Hollaway, 1992; Avseth et al., 2000; Mukherji et al., 2001).

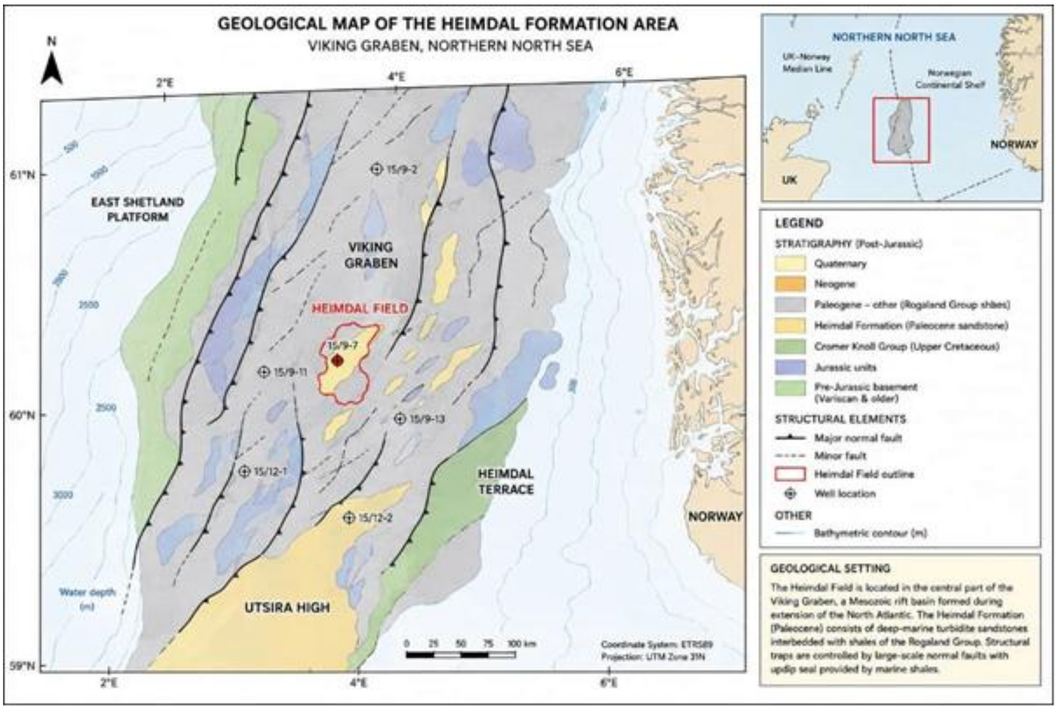


Figure 1. Geological map of the area covering Heimdal Formation.

Hydrocarbon entrapment is controlled by structural closures associated with faulting and stratigraphic pinch-outs (Avseth et al., 2001a). Regional marine shales provide effective seals, while mature Jurassic source rocks constitute the principal hydrocarbon source (Whyatt et al., 1992).

## III. Materials And Methods

Data Description

The study utilized wireline log data acquired from five exploration wells penetrating the Paleocene Heimdal Formation in the Northern North Sea. The available datasets comprised compressional-wave velocity (Vp), bulk density (RHOB), gamma-ray (GR), neutron porosity (NPHI), and shear-wave velocity (Vs) logs (Avseth et al., 2005). Among the five wells, Well 2 contained the most complete petrophysical dataset and was therefore selected as the reference well for detailed rock physics analysis and fluid substitution modelling.

Where shear-wave velocity logs were unavailable, Vs was estimated using the Greenberg and Castagna empirical relationship following calibration with measured Vp–Vs data from Well 2. The generated shear-wave logs were subsequently validated and incorporated into the elastic property analysis. Reservoir conditions used in the modelling included an effective pressure of approximately 20 MPa and a reservoir temperature of about 70 °C. Fluid properties comprised brine density of 1.09 g $cm^{-3}$, brine bulk modulus of 2.8 GPa, oil density of 0.78 g $cm^{-3}$, oil gravity of 32° API, and a gas–oil ratio of 64 $Sm^3/Sm^3$. The mineralogical composition of the reservoir matrix was represented by quartz and clay with bulk moduli of 36.8 GPa and 15 GPa, respectively.

The target reservoir interval extends from approximately 2154 to 2204 m measured depth, corresponding to the principal hydrocarbon-bearing sandstone unit within the Heimdal Formation. The selected interval exhibits relatively high porosity and favourable reservoir quality, making it suitable for evaluating the influence of pore-fluid substitution on seismic properties (Batzle and Wang, 1992).

Prior to interpretation, all well logs were subjected to quality control procedures to eliminate spurious measurements and ensure consistency between the different logging tools. Minor depth mismatches were corrected, and the logs were normalized where necessary to improve data reliability.

Petrophysical Evaluation

Petrophysical analysis was performed to estimate reservoir properties controlling seismic behaviour. Porosity was calculated from density logs using standard density–porosity relationships, while shale volume was estimated from gamma-ray logs (Fig. 2). Lithological discrimination was achieved by integrating gamma-ray, porosity, and density responses, enabling identification of clean sandstone, silty sandstone, shale, and cemented sandstone intervals within the Heimdal reservoir.

Elastic properties, including acoustic impedance (AI), shear impedance (SI), Vp/Vs ratio, were computed from the calibrated velocity and density logs to establish relationships between rock properties and pore-fluid composition.

### Shear-Wave Velocity Estimation

Measured shear-wave velocity logs were unavailable in some wells. Consequently, missing Vs logs were estimated using the empirical Greenberg and Castagna relationship following calibration with measured Vp–Vs data obtained from Well 2 (Greenberg and Castagna, 1992). The calibrated relationship enabled reliable prediction of shear-wave velocities throughout the study interval and facilitated computation of elastic parameters required for rock physics analysis. Comparison between predicted and measured Vs logs demonstrated good agreement, confirming the suitability of the empirical model for the Heimdal Formation.

### Rock Physics Modelling

Rock physics analysis was undertaken using RokDoc software to investigate the relationship between petrophysical properties and seismic responses. Cross-plots of Vp, Vs, density, porosity, shale volume, and acoustic impedance were generated to identify lithological trends and evaluate the influence of fluid saturation on elastic behaviour (Mukherji et al., 2001; Jack et al., 2009). The analysis focused on the upper 50 m interval of the Heimdal Formation, where reservoir sandstones display significant hydrocarbon potential (Fig. 2). Average elastic properties derived from this interval served as input parameters for subsequent fluid substitution modelling.

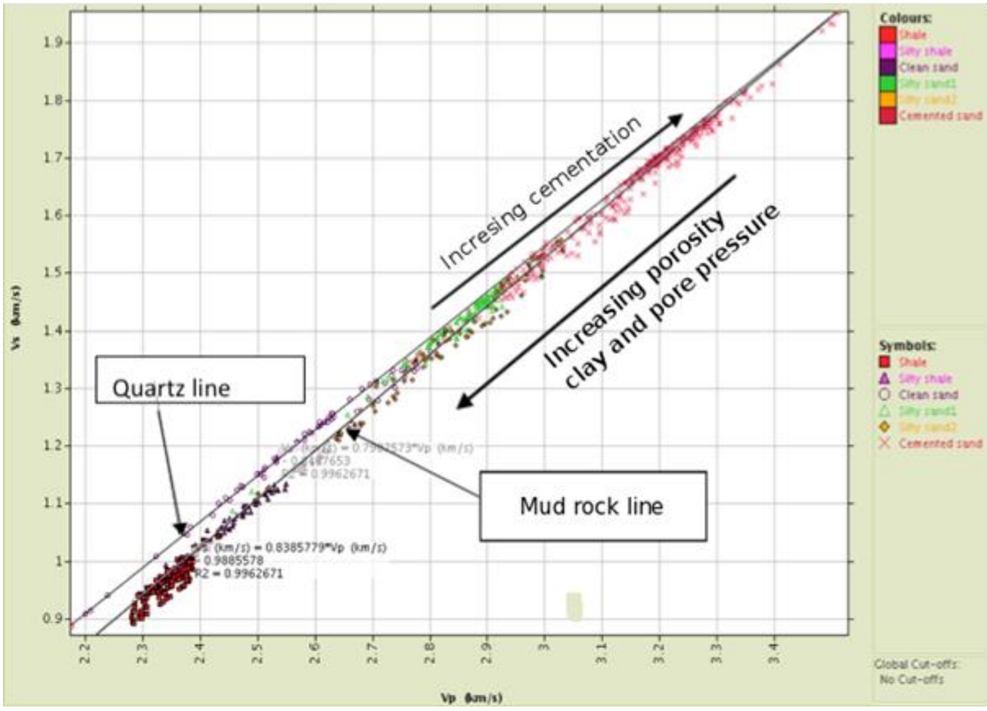


Figure 2. Cross-plot of Vs versus Vp for the six different lithofacies. Colours and symbols show classification of samples according to major lithological groups. The rock units are assumed to be water-saturated. The well interval shown is 2155-2299m measured depth.

### Fluid Substitution Modelling

Fluid substitution was performed using Gassmann's fluid substitution theory to predict the elastic response of the reservoir following replacement of in-situ pore fluids. The workflow involved estimating dry-rock elastic properties from the measured saturated logs and subsequently replacing the original pore fluid with oil and gas under identical pressure and temperature conditions.

Fluid properties were computed using the Batzle and Wang equations, while Gassmann's equations (Gassman, 1951) were employed to calculate the resulting saturated bulk modulus, density, and seismic velocities. The analysis assumed isotropic, homogeneous reservoir rocks with interconnected pore spaces and negligible fluid effects on shear modulus.

In fluid substitution, there are two effects; a change in bulk density and a change in rock compressibility. Compressibility of a dry rock can be expressed as the sum of the compressibility of minerals and the pore space.

$$\frac{1}{K_{rock}} = \frac{1}{K_{mineral}} + \frac{\emptyset}{K_{\phi}} \qquad 1$$

Where $K_{\phi}$ is the pore space stiffness

Compressibility of a saturated rock can be expressed as:

$$\frac{1}{K_{sat}} = \frac{1}{K_{mineral}} + \frac{\emptyset}{(K_{\phi} + K_{fluid})} \qquad 2$$

It is noted that changing the pore fluid changes the pore-space stiffness. Also, a stiff rock with high pore space stiffness is insensitive to changes of fluids. The low-frequency Gassmann theory predicts the resulting increase in effective bulk modulus, $K_{sat}$ , of the saturated rock through the following equation

$$\frac{K_{sat}}{K_0 - K_{sat}} = \frac{K_{dry}}{K_0 - K_{dry}} + \frac{K_{fl}}{\emptyset(K_0 - K_{fl})} \qquad 3$$

and

$$\mu_{sat} = \mu_{dry} \qquad 4$$

where

$K_{sat}$ = effective bulk modulus of the rock with pore fluid
$K_{dry}$ = effective bul k modulus of dry rock
$K_0$ = bulk modulus of mineral material making up the rock
$K_{fl}$ = effective bulk modulus of pore fluid
$\emptyset$ = porosity
$\mu_{sat}$ = effective shear modulus of rock with pore fluid
$\mu_{dry}$ = *effective shear modulus of dry rock*

Strictly speaking, Gassmann's relations use the difference between the dry rock bulk modulus and mineral modulus to ascertain the compressibility of the pore space. This is independent of any particular pore shape. By adding the saturating fluid modulus, the saturated rock bulk modulus is calculated. Rock shear modulus is assumed to be unaffected by fluids. The principal outputs of the fluid substitution modelling included changes in P-wave velocity (Vp), S-wave velocity (Vs), bulk density, Vp/Vs ratio, under different fluid saturation scenarios.

## IV. Results And Discussion

### Petrophysical Characterisation of the Heimdal Formation

Petrophysical evaluation of the well-log data revealed considerable vertical heterogeneity within the Heimdal Formation, reflecting alternating sandstone and shale units typical of deep-marine turbidite systems. Gamma-ray logs effectively differentiated clean reservoir sandstones from shale-rich intervals, while density-derived porosity indicated generally good reservoir quality within the principal sandstone bodies (Fig.3).

The interpreted reservoir interval, located between approximately 2154 and 2204 m, exhibits porosity values averaging about 27%, consistent with productive Paleocene sandstone reservoirs in the Northern North Sea (Avseth et al., 2009). Acoustic velocity and density increase progressively from unconsolidated clean sandstone to cemented sandstone, indicating that diagenesis exerts significant control on the elastic properties of the reservoir (Figs. 2 &3). Cemented sandstone intervals display the highest P-wave velocity, S-wave velocity, and bulk density, whereas clean sandstones are characterised by lower acoustic impedance and improved reservoir quality.

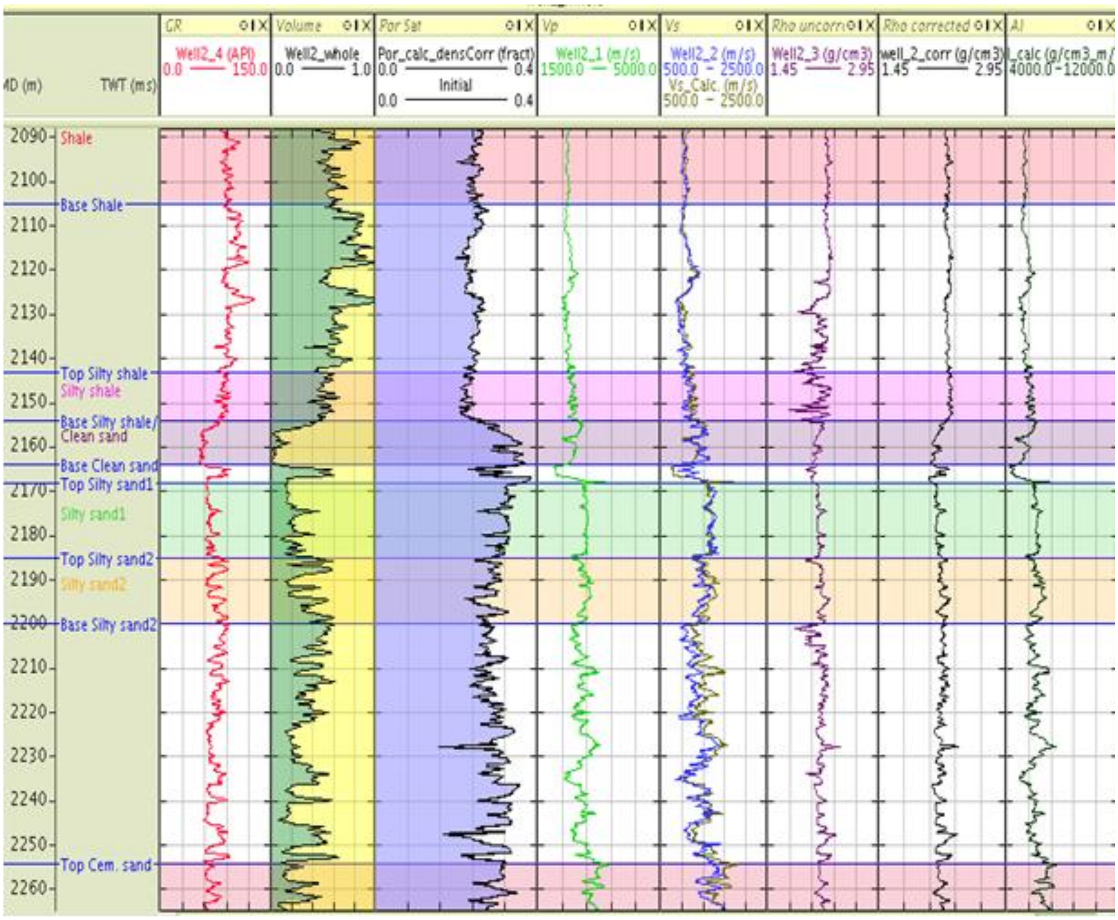


Figure 3. Well-log data from well 2 showing part of the target Heimdal sandstone units (2100-2300m) measured depth. Acoustic impedance (AI) shown in track 9, shear velocity (Vs) in track 6, Porosity log in track 3, and Vshale in track 3 are calculated. Calculation procedure is described in section 3.

The calibrated Greenberg–Castagna relationship produced reliable estimates of shear-wave velocity for wells lacking measured Vs logs. The predicted Vs values showed good agreement with measured data, allowing calculation of additional elastic attributes, including acoustic impedance (AI) and Vp/Vs ratio.

The shale volume estimated from gamma-ray logs shows an inverse relationship with both acoustic velocity and density. Increasing shale content results in lower seismic velocities due to the presence of clay minerals, whereas cleaner sandstone intervals are characterized by higher elastic stiffness and superior reservoir quality. These observations demonstrate that lithology and diagenesis exert strong controls on the elastic behaviour of the Heimdal Formation.

## Elastic Property Analysis

The computed elastic parameters clearly demonstrate the influence of lithology and pore-fluid composition on the seismic response of the Heimdal Formation. Acoustic impedance increases with increasing rock consolidation and decreasing porosity, whereas lower impedance values are associated with clean, porous reservoir sandstones (Fig. 3).

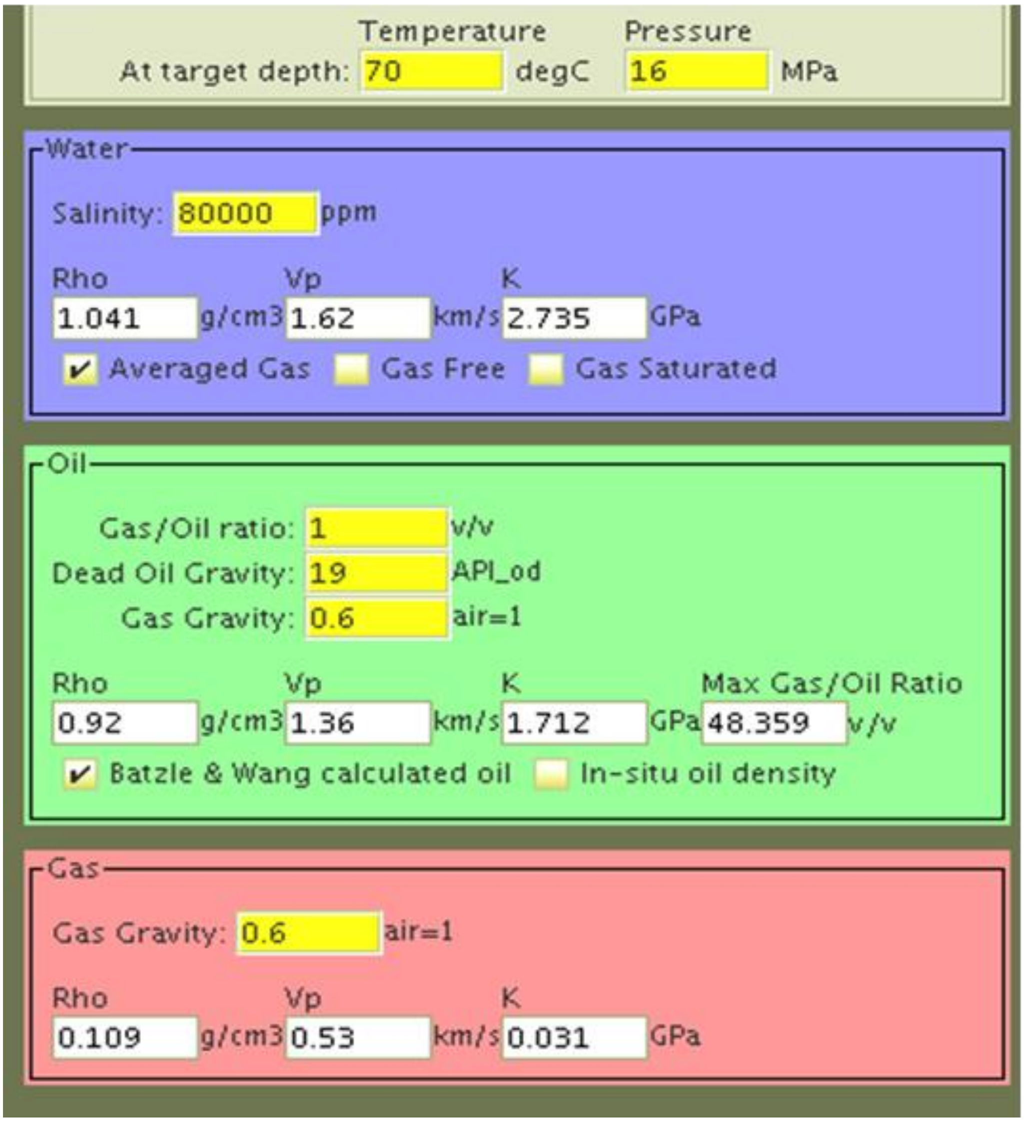
The calculated Vp/Vs ratio proved particularly sensitive to changes in pore-fluid composition, making it an effective discriminator between hydrocarbon-bearing and water-saturated reservoir intervals. This observation confirms that combining impedance attributes with velocity ratios can provide a more reliable approach for reservoir characterisation than using any single elastic parameter (Avseth et al., 2001a)

Fluid Substitution Results

Fluid substitution modelling using Gassmann's equations quantified the seismic response of the Heimdal reservoir following replacement of brine with oil and gas. The results demonstrate that pore-fluid composition significantly modifies the elastic behaviour of the reservoir. Replacement of brine by oil produced a moderate reduction in compressional-wave velocity and bulk density while producing minimal change in shear-wave velocity, consistent with the theoretical assumption that pore fluids have negligible influence on rock shear modulus (Fig. 4). The reduction in acoustic impedance indicates enhanced seismic contrast between hydrocarbon-bearing sandstone and surrounding shale units.

Gas substitution generated the largest elastic response. Average P-wave velocity decreased from approximately 2.59 km/s in the original brine-saturated reservoir to approximately 2.10 km/s following gas substitution, accompanied by a substantial reduction in bulk density. In contrast, S-wave velocity remained nearly constant throughout the substitution process (Fig. 4). These results demonstrate that P-wave velocity is considerably more sensitive to pore-fluid variations than S-wave velocity, confirming its usefulness in hydrocarbon detection.

The decrease in acoustic impedance associated with gas saturation is expected to strengthen reflection amplitudes at shale–sand interfaces, thereby improving the detectability of gas-bearing intervals on seismic data. These findings are consistent with established rock physics theory and demonstrate the effectiveness of Gassmann fluid substitution for predicting seismic signatures of fluid changes (Avseth et al., 2001a; Mukherji et al., 2002).



At target depth: Temperature 70 degC, Pressure 16 MPa

Water
Salinity: 80000 ppm
Rho 1.041 g/cm3 Vp 1.62 km/s K 2.735 GPa
☑ Averaged Gas ☐ Gas Free ☐ Gas Saturated

Oil
Gas/Oil ratio: 1 v/v
Dead Oil Gravity: 19 API_od
Gas Gravity: 0.6 air=1
Rho 0.92 g/cm3 Vp 1.36 km/s K 1.712 GPa Max Gas/Oil Ratio 48.359 v/v
☑ Batzle & Wang calculated oil ☐ In-situ oil density

Gas
Gas Gravity: 0.6 air=1
Rho 0.109 g/cm3 Vp 0.53 km/s K 0.031 GPa

Figure 4. Summary of the input fluid parameters and the output fluid properties generated using Batzle and Wang relations. Cells shaded yellow represent the inputted fluid parameters and cells shaded white are the output fluid properties.

Fluid Substitution Analysis

The Fluid substitution was done in the upper 50m of the Heimdal Formation sands to calculate the effect of fluid substitution on seismic properties of the reservoir sands from Gassmann (1951) equation. The equation calculates the bulk modulus of a fluid saturated porous medium using the known bulk moduli of the solid matrix, the frame, and the pore fluid. For a rock, the solid matrix consists of the rock-forming minerals, the frame refers to the skeleton rock sample, and the pore fluid can be oil or a gas. Before the fluid substitution was carried out, there is a need to know the acoustic properties of the oil and mud filtrate. These were calculated from Batzle and Wang's relations in Rokdoc$^{TM}$.

The following parameters were used as an input for calculating fluid properties to be used for fluid substitution: reservoir pressure = 20 MPa, reservoir temperature = 70$^0$C, reservoir water salinity = 80,000 ppm NaCl and gas density = 0.6 relative to air. Averaged gas was used to account for the effect of gas saturation of brine. The parameters are part of the petrophysical data provided.

The RokDoc fluid substitution function is used to perform fluid substitution on a rock by implementing Gassmann's algorithm. After calculating fluid parameters using Batzle and Wang relation, there is a need to calculate dry rock frame parameters from average initial saturations and then substitute in the initial fluid mixture to determine the predicted Vp, Vs and Rho for new saturation.

The parameters used in the Gassmann's fluid substitution are the averages of the upper 50m of the Heimdal Formation sand i.e. Vp of '2588' m/s, Vs of '1196' m/s, and a density (Rho) of '2.21' g/cc. Because the Heimdal Formation sand comprises of interbedded sand and shale units, multi mineral parameter was used were the volume fraction of quartz was taken to be "0.7" and that of shale "0.3". The zone of interest is assumed to be fully water saturated case for the zones of interest. The table below (Table 1 & 2) shows the outcome of the fluid substitution using the above parameters.

**Table 1.** Calculated averages of Vp, Vs, and Rho and their standard deviations for the different lithofacies in the Heimdal Formation sands. The velocities are averages of the respective lithologic intervals form the well logs**.**

| **Name** | **Measured depth (m)** | **Vp Mean (m/s)** | **Vs Mean (m/s)** | **Rho Mean (g/cc)** | **Vp Std Dev (m/s)** | **Vs Std Dev (m/s)** | **Rho Std Dev (g/cc)** |
|---|---|---|---|---|---|---|---|
| Shale | 2078-2105 | 2340 | 950 | 2.25 | 320.10 | 34.00 | 0.016 |
| Silty Shale | 2143-2154 | 2501 | 1001 | 2.28 | 80.29 | 51.25 | 0.016 |
| Clean sand | 2154-2164 | 2553 | 1222 | 2.11 | 132.19 | 141.07 | 0.041 |
| Silty sand1 | 2168-2185 | 2856 | 1439 | 2.13 | 77.12 | 72.81 | 0.019 |
| Silty sand2 | 2185-2200 | 2894 | 1298 | 2.18 | 104.72 | 81.38 | 0.02 |
| Cemented sand | 2254-2300 | 3123 | 1485 | 2.23 | 135.72 | 129.53 | 0.052 |
| Upper 50m of the Heimdal S. | 2154-2204 | 2588 | 1196 | 2.21 | 276.81 | 134.46 | 0.039 |

Table 2. Calculated changes in rock elastic moduli after fluid substitution from brine to oil and from brine to gas. KD represents dry bulk modulus, Mu represents shear modulus and RhoD represents dry density.

| ***Fluid Substitution for the upper 50m of the Heimdal Formation Sand*** | | | | | |
|---|---|---|---|---|---|
| **Brine to Oil** | | | | | |
| **Dry values** | | Poisson ratio | KD | Mu | RhoD |
| | | 0.235 | 4.544GPa | 2.926GPa | 1.947g/cm3 |
| | | | | | |
| **Wet values** | | | Vp(Km/s) | Vs(Km/s) | Rho(g/cm3) |
| | *Porosity(frac)* | *0.27* | 2.3 | 1.2 | 2.16 |
| | *Por. Pert(frac).* | *0.32* | 2.2 | 1.1 | 2.09 |
| **Brine to Gas** | | | | | |
| | | | | | |
| **Dry values** | | Poisson ratio | KD | Mu | RhoD |
| | | 0.235 | 4.544GPa | 2.926GPa | 1.947g/cm3 |
| | | | | | |
| **Wet values** | | | Vp(Km/s) | Vs(Km/s) | Rho(g/cm3) |
| | *Porosity(frac)* | *0.27* | 2.1 | 1.2 | 1.99 |
| | *Por. Pert.(frac)* | *0.32* | 2.0 | 1.2 | 1.85 |

It is worthy to note that the Gassmann's equation used in doing the fluid substitution hinges on the following basic assumptions:

- The rock fluid system is closed.
- The pore paces are interconnected.
- Pores are filled with a frictionless fluid
- The rocks are macroscopically homogeneous.
- Properties of gas, oil and water are simplified

Despite these assumptions, Gassmann's equation is handy in calculating the AVO of different fluids through shale - sand contact from which information about type of fluid content can be gained.

Implications for Seismic Reservoir Characterisation

The observed variations in elastic properties following fluid substitution have important implications for seismic interpretation and reservoir evaluation. The reduction in acoustic impedance and increase in Vp/Vs sensitivity associated with hydrocarbon saturation indicate that these attributes can effectively distinguish hydrocarbon-bearing sandstones from brine-filled reservoirs.

Furthermore, the predicted elastic responses provide valuable constraints for seismic inversion, amplitude variation with offset (AVO) analysis, and time-lapse (4D) seismic monitoring. Integrating well-log analysis with rock physics modelling reduces uncertainty in fluid prediction and improves confidence in reservoir delineation, particularly within thinly bedded and heterogeneous turbidite reservoirs such as the Heimdal Formation.

Overall, the results confirm that fluid substitution modelling is an effective tool for evaluating reservoir fluid effects and enhancing seismic reservoir characterisation in the Northern North Sea. The methodology developed in this study can also be applied to analogous deep-water sandstone reservoirs where direct identification of pore fluids from conventional seismic interpretation remains challenging.

## V. Conclusions

This study evaluated the influence of pore-fluid substitution on the elastic and seismic properties of the Heimdal Formation reservoir in the Northern North Sea using Gassmann's fluid substitution theory integrated with well-log and rock physics analyses. The results demonstrate that fluid composition exerts a significant control on reservoir elastic behaviour and, consequently, on seismic response.

Petrophysical evaluation identified the Heimdal Formation as a heterogeneous deep-marine turbidite reservoir comprising alternating clean sandstone, silty sandstone, shale, and cemented sandstone units. The reservoir interval exhibits favourable petrophysical characteristics, with average porosity of approximately 27%, indicating good hydrocarbon storage potential. Variations in seismic velocities and density were found to be strongly influenced by lithology, porosity, and the degree of cementation.

Fluid substitution modelling showed that replacing brine with hydrocarbons produces measurable changes in elastic properties. Gas substitution resulted in the greatest reduction in compressional-wave velocity and acoustic impedance, whereas shear-wave velocity remained essentially unchanged, consistent with the theoretical assumptions of Gassmann's model. The pronounced reduction in acoustic impedance and the increased sensitivity of the Vp/Vs ratio confirm that these elastic attributes are effective indicators of pore-fluid variations and hydrocarbon presence.

Overall, the findings confirm that Gassmann-based fluid substitution is an effective tool for evaluating fluid-related seismic signatures in the Heimdal Formation. The methodology presented in this study is applicable to other Paleocene deep-water sandstone reservoirs within the North Sea and similar sedimentary basins worldwide, where accurate prediction of pore-fluid distribution is critical for hydrocarbon exploration and reservoir management.

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