Application of seismic attributes in structural and facies modeling for volume calculation on statford formation, north viking graben

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Abstract. Viking Graben is the dominant main structure in the northern North Sea. The study area is located on North Viking Graben. In this study focused on the formation of Statfjord. The formation was precipitated during the late Triassic until the early Jurassic. This layer is a sandstone sediment. The reservoir characterization of the coating will be done by integration of seismic attribute analysis and seismic inversion. Seismic attribute analysis is performed to identify the boundary layer, which is indicated by the difference between the two layers and the inversion seismic done to show the acoustic impedance which is useful to know the characteristics of the layer. Both attributes (seismic amplitude and acoustic impedance) are expected to investigate the complete reservoir. Based on the results of interpretation and analysis of the seismic attribute will be built geological model as a basis for treating reservoir volume calculations by volumetric methods. In this research, the results obtained in the form of porosity distribution map with a large porosity value of 0.125 - 0.225 (%) and STOIP distribution map with a large reservoir volume of 186 × 106 sm3

1. Introduction

The northern North Sea belongs to the part of Norway. The North Sea is dominated by the Viking Graben structure which stretches from north to south of the North Sea. The North Sea is a complex area structure that has undergone several rifting phases throughout its history. The rift system in the North Sea is located in the perarian region of England and Norway, where there are many productive oil fields and consist of three main structures namely, Moray Firth Basin, Central Graben, and Viking Graben [1]. Viking Graben is formed by rifting in the Jurassic period and affects approximately 40 km of the width of the sedimentary basin. In the mid-Triassic period until the beginning of the Jurassic there was a trend in sediment thickness. Changes in thickness are thought to describe a continuous decline in the basin which by cooling the temperature after rifting in the early Triassic period stopped. Significant changes in thickness occur so that it separates the Horda Platform from Viking Graben.

The change in thickness is called Oseberg fault. The difference in thickness of the Statfjord Formation changed along the Oseberg fault with a decrease in thickness moving towards the south. On it was deposited by Dunlin Group which has the same trend of thickness on the fault [2]. The developing reservoir is the area of shallow sea sand rock deposition to fluvial from the Statfjord Formation, Cook Formation, and Brent Group. This deposit is at the end of the Triassic age until the early Jurassic. In this study a geological model will be made based on seismic data and well data that can describe reservoir distribution in the layer model. The reservoir modeling is based on the results of
the interpretation and analysis of the visualization integration of several seismic attributes which correlated with geological structure determination.

2. Methods
2.1. Seismic Method

the seismic interpretation process that is determining geological markers on the well log and well correlation is carried out at the stratigraphic modeling stage in the well log. this step uses the seismic method. this method is used to find out the underground image by utilizing seismic waves and based on snellius law which is developed from the Huygens principle [3]. One of the typical acoustic properties of rocks is acoustic impedance, which is the physical ability of rocks to pass through seismic waves. Reflection seismic will be formed if there is a change in acoustic impedance. Mathematically the acoustic impedance of rocks is the multiplication of the velocity of a seismic wave with the density of a rock. Any change in acoustic impedance below the earth's surface will cause a reflection coefficient [3]. When a seismic wave forms an angle of incidence perpendicular to the reflected area (normal incident), the reflection coefficient can be formulated (see Equation 1 and 2).

\[
IA = V \times \rho
\]

Where, A as acoustic impedance, V as seismic wave speed and \( \rho \) as rock density

\[
KR = \frac{IA_2 - IA_1}{IA_2 + IA_1} = \frac{V_2\rho_2 - V_1\rho_1}{V_2\rho_2 + V_1\rho_1}
\]

WhereKR as reflection coefficient, \( IA_{2\text{as}} \) First layer acoustic impedance, \( IA_{2\text{as}} \) second layer acoustic impedance, \( V_{1,2\text{as}} \) seismic wave velocity in the first and second layers and \( \rho_{1,2\text{as}} \) first and second rock layer density

2.2. Structural modeling

Structural modeling includes the process of identifying faults from the results of seismic attribute mapping, determination of horizon lines, determination of grid models, depth conversion, zoning of hydrocarbon potential areas, and determination of coatings. This modeling uses the Amplitude Attribute RMS method (Equation 3).

\[
A_{\text{rms}} = \sqrt{\frac{1}{N} \sum_{i=1}^{N} a_i^2}
\]

Where N as amount of amplitude sample in the analysis window and \( a \) as amount of amplitude.

2.3. Property modeling

Property modeling process includes geometry modeling, upscaling well log data, facies modeling from analysis of symmetric attribute mapping for facies analysis, to modeling petrophysical properties such as porosity and net to gross. This model uses rock porosity calculations (Equation 4 and 5) that compare the pores in rocks to the total volume of all rocks expressed in percent.

\[
\phi_D = \frac{\rho_m - \rho_b}{\rho_m - \rho_f}
\]

\[
\phi_{DN} = \sqrt{\phi_D^2 + \phi_N^2}
\]

Where \( \phi_D \) as porosity density, \( \rho_m \) as Rock matrix density, \( \rho_b \) as bulk density of rocks, \( \rho_f \) as density of drilling mud liquid, \( \phi_N \) as Neutron porosity and \( \phi_{DN} \) Porosity of neutron density

2.4. Calculation of Hydrocarbon Reserves

Volumetric calculations are performed to determine the volume of hydrocarbons. The models that have been made are used as inputs in the hydrocarbon calculation process. This Calculation use
STOIIP. STOIIP is the estimation of all oil (oil) in one reservoir, both that can be produced and which cannot be produced. The amount of STOIIP can be determined using the following Equation 6.

\[ \text{STOIIP} = V_b \times \text{NTG} \times \Phi \times (1 - Sw)/Bo \]  

(6)

Where STOIIP as Stock Tank Oil Initial In Place (STB, Stock Tank Barrels), \(V_b\) as volume bulk dari reservoar (acre.ft), NTG as Net To gross and \(\Phi\) as porosity (%).

3. Results and Discussion

3.1. Correlation of Well

Correlation of well to determine reservoir zone by looking at gamma ray log data, log density, and neutron porosity log. Based on the results of the correlation of well, the reservoir zone is a sandstone characterized by a low gamma ray log value and a crossover between density log and neutron log data. as shown in Figure 1 and 2.

Figure 1. Determination of reservoir zone in well 1.

Figure 2. Determination of reservoir zone in well 2.

Figure 3. Well seismic tie well 1 on inline 4055 and crossline 4906

Figure 4. Well seismic tie well 2 on inline 4825 and crossline 4928.

3.2. Well seismic tie

Well seismic tie is a process of correlation between well data and seismic data. In Figure 3 and 4 show the well seismic tie process. In this process, stretch and squeeze are carried out to determine the value of the actual trace seismic correlation with synthetic seismic trace. The compatibility between trace seismic and synthetic trace has a correlation value between 0 and 1, the better the correlation will be close to the value 1. The correlation value of the well seismic tie process is the correlation in well 1 of 0.712 and in well 2 of 0.882.

3.3. Picking Horizon

Based on figure, Zones indicated for hydrocarbons in seismic data can be identified by the presence of brightspot lines in the seismic cross section of the crossline 4896 with time 3400 - 3414 ms where hydrocarbons indicated in well 2 (see Figure 5).
3.4. Petrophysical Analysis

Petrophysical analysis is used to characterize reservoir zones. In Figure 6, there is a deposition zone in well 2, has a low gamma ray value, high porosity, and low impedance where the reservoir zone has a thickness of 20 meters. The depositional environment can be identified based on gamma ray log data which has an upward and blocky coarsening pattern in which the pattern is characteristic of the deltaic depositional environment. The identification of this depositional environment is in accordance with regional geological data which says that the Statford formation is a delta deposition environment.

Based on the acoustic crossplot data impedance with gamma ray shown by Figure 7 and crossplot the acoustic impedance impedance with the porosity shown in figure 8. It can be seen that the correlation between acoustic impedance, gamma ray and porosity shows that the reservoir zone is in an area that has a low acoustic impedance value ranging from 7800 - 10500 (m/s) * (g/cc) indicated by the yellow zone. The yellow zone shows that the reservoir zone has a low acoustic impedance value and low gamma ray which is below 46 API and good porosity, which is 0.125 - 0.225%.

Figure 5. The indication of a bright spot was confirmed by the crossover of log density and log neutron porosity in well 2.

Figure 6. Deposition zone in well 2.

Figure 7. Crossplot impedance with gamma ray in well 2.

Figure 8. Crossplot impedance with porosity in well 2.

Figure 9. Model-based inversion section on xline 4926.
3.5. Seismic Invasion
Seismic invasion is done to transform reflection seismic data into quantitative values of physical properties and reservoir descriptions. In Figure 9 shows that the distribution of the AI (Acoustic Impedance) value of the seismic cross section can separate lithology. The shale layer is characterized by a high acoustic impedance value that is in the impedance value between 12748-15000 (g/cc) * (m/s) and is indicated by blue to purple. Whereas sandstones are characterized by low acoustic impedance values found in the impedance values 7794-10947 (g/cc) * (m/s) indicated by green to red. In Figure 10 it also shows that the dominant sandstone zone is in the west which is bordered by a large fault on the east which is characterized by green to red. The area is a reservoir prospect zone, because the area has a large volume of sandstone as indicated by a low acoustic impedance value.

3.6. Amplitude Attribute RMS
The RMS attribute (root mean square) is carried out on a time structure map with input data in the form of the volume of initial 3D seismic data to determine the distribution of sandstones. In Figure 11 shows that the dominant sandstone zone is in the west which is bordered by a large fault on the east which is characterized by Blue to Purple, while the smaller the amplitude value of the deposited rock is more shaly. Based on the AI distribution map (Figure 10) and the amplitude distribution map (Figure 11), it shows that the reservoir zone is to the west of the Statfjord formation and the sandstone reservoir.

3.7. Depth Structure Map
The surfaces of the structures that make up the Statfjord Formation are formed in the 3D grid model in the time domain. The 3D grid model in the time domain is the initial model which is then converted into the depth domain. This process is carried out to determine the actual depth of the layer and it’s used in calculating the volume of hydrocarbons.

Figure 10. AI inversion distribution map
Figure 11. RMS amplitude map
Figure 12. Map of the top Statfjord depth structure
Figure 13. Reservoir zones and non-reservoir zones
In Figure 12 it can be seen that the hydrocarbon potential zone is an anticline and is limited by a large fault. The top reservoir layer is in the stratigraphic column at the end of the Triassic period. The west and east Zone have a structure that is higher than the center. In the reservoir zone that has been determined based on AI maps and amplitude maps, the zone has a structure in the form of an anticline and the presence of faults creates a trap in the reservoir zone.

3.8. Zoning and Coating

The zoning process is carried out to determine the distance between the horizon zones. Coating in the reservoir zone is divided by using an average cell thickness of about 2 meters, so that the separation of sandstone rock and shandy shale types can be more accurate because the reservoir zone has a thickness of approximately 25 meters. In figure 13. The reservoir zone is in the form of sandstone and sandy shale zones which are shown in yellow and brown parts, whereas in the non reservoir zone is shown in green.

3.9. Determination of contact limits

In this study, oil water contact (OWC) or the so-called water and oil contact limit is at a depth of 4200 meters which is determined based on the lower limit of the reservoir zone shown in the well log as shown in Figure 14.

![Figure 14](image1.png) Water contact limits on the field

![Figure 15](image2.png) Histogram of gamma ray logs with scale up results

![Figure 16](image3.png) Facies map in the reservoir zone

![Figure 17](image4.png) Crossplot porosity map with acoustic impedance

3.10. Facies Modeling

Facies modeling needs to be made and upscale into a 3D grid before modeling the property. Facies determination is determined based on the gamma ray log that is used to classify facies. In Figure 15...
shows a comparison between new facies (blue), scale up cells (green), and gamma ray log cells (red) in the reservoir zone. There are three columns, column 0 is a percentage of sandstones, column 1 is the percentage of shale, column 2 is the percentage of sandy shale. Column 1 is 0, because the reservoir zone is a sandy blocky area. The results of the scale up process look good because there are no significant deviations in the three cells. Figure 16 shows a low value gamma ray log shown in yellow. In this process focusing on boundary field is based on AI inversion distribution map and rms amplitude attribute distribution map. The potentially hydrocarbon reservoir zone is west of the Statford layer.

3.11. Porosity Modeling
Porosity maps can be made with the equation obtained from the crossplot between porosity and acoustic impedance. Figure 17 shows the crossplot of the porosity log and acoustic impedance with an inverse linear relationship. In the cross plot between porosity log and acoustic impedance, the reservoir zone shown in yellow has an acoustic impedance value of 7800—10500(m/s)²(g/cc), porosity values of 0.125—0.225% and low gamma ray values, 24 – 46API. From the crossplot, we also get the equation that connects the acoustic impedance with porosity. The equation of porosity is

Porosity = -0.0000250357 \times AI + 0.386503.

This equation can be used to convert the acoustic impedance volume into porosity volume, so that a porosity distribution map is produced. Figure 18 shows the pattern of porosity distribution structure in the reservoir zone, where the high porosity value is shown in purple, while the smaller the porosity value of the color will turn red.

3.12. Net to Gross Modeling
Net to gross (NTG) modeling is made based on the cut off on gamma ray logs. Where if the gamma ray log value is less than 46 then it is a sandstone and if the gamma ray log value is more than 46 then it is sandy shale. Mapping net to gross distribution is intended to determine the geometry of sedimentation facies. Based on the geometry of facies can be interpreted the direction of sedimentation in the sandstone deposition process at the study interval. Figure 19 illustrates the distribution of sandstones shown in yellow and red shows the distribution of sandy shale.

3.13. Water saturation modeling
Water saturation (SW) modeling can show the distribution of water fluid levels in the reservoir. A reservoir will be better if the water saturation value gets lower. In this study water saturation modeling was not carried out because there was no log resistivity or SW log. The SW value used in this study is a constant in an oil-filled reservoir which is 0.3 [5].

3.14. Volume Calculation
The results of the previous modeling are used as inputs in calculating hydrocarbon reserves. In addition, the reservoir constant values used in calculating hydrocarbon volumes include: water
saturation (SW) of 0.3, the formation factor of volume oil (Bo) was 1.3 and recovery factor (Rfo) was 0.3. **Table 1** shows the results of volumetric reservoir calculations at the Statford Formation layer.

**Table 1.** Results of oil volume on the Statford layer

| Case    | Bulk Volume [10^6 m³] | Net Volume [10^6 m³] | Pore Volume [10^6 m³] | HCPV oil [10^6 m³] | STOIIP [10^6 sm³] | Recovery oil [10^6 sm³] |
|---------|----------------------|----------------------|-----------------------|---------------------|-------------------|------------------------|
| Volume  | 4187                 | 1228                 | 371                   | 241                 | 186               | 56                     |

**Figure 20.** Distribution of bulk volume in the top reservoir

**Figure 21.** Distribution of net volume in the top reservoir

**Figure 22.** Distribution of volume pore in the top reservoir

**Figure 23.** Distribution of HCPV oil in the top reservoir

**Figure 24.** Distribution of STOIIP in the top reservoir

4. **Conclusion**

Based on the results of the interpretation, a description of the structure of the Statford Formation is folded and there is one large fault. The target reservoir zone is to the west of the Statford Formation and the retrograde model is an anticline. The reservoir target is dominated by sandstone with a thickness of ± 20 meters and has a relatively low acoustic impedance value ranging from 7794—10947 (g/cc)*(m/s) and has a porosity value of 0.125 - 0.225%. Reservoir properties that can be
modeled include facies maps, porosity maps, and net to gross maps. Calculation of volumetric oil initial in place (STOIIP) tank in the Statjford Formation of $186 \times 10^6 \text{sm}^3$.

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