CHAPTER 1

Introduction

1.1 Problem Statement and Motivation

To analyse rock properties such as lithology and porosity that could not be done by normal seismic models and routine seismic amplitude attributes, seismic inversion should be used to solve this problem by applying to seismic volumes using rock properties such as velocities and densities. The results of seismic inversion will provide new inverted seismic models and inverted seismic attribute maps to be evidences and gain confident in petroleum exploration. The seismic inversion model can be generated by various methods depending on available data, seismic quality, and lithology.

To generate inversion model, it needs some parameters as the initial value for model calculation which can be derived from amplitude variation with offset (AVO) analysis. The term AVO was first discussed by Ostrander in 1982 was described to seismic amplitude variation with distance or offset between source and receiver. The changes are typically associated with lithology and fluid content in rocks above and below the reflector. AVO analysis is a technique used to evaluate porosity, density, velocity, lithology and fluid content of reservoirs (Almutlaq and Margrave, 2010).

Seismic inversion normally starts with rock physics study that can be obtained the elastic properties of rock. These properties include acoustic impedance (AI), shear impedance (SI), elastic impedance (EI) and V_P/V_S, and it can be used to define hydrocarbon related lithofacies (Singh, 2007).

Pre-stack simultaneous inversion is a type of inversion that can help identifying rock and fluid properties within reservoirs. It is used to derive P-impedances (Z_P), S-impedances (Z_S) and density directly using Aki and Richard approximation (Aki and Richards, 1980). The products can be used to estimate V_P/V_S, as this is very useful property in the identification of fluid type of reservoirs (Maver and Rasmussen, 2004).

1.2 Background of Study Area

A gas field in this study is located in the North Malay Basin (Figure 1-1) where covers an area of approximately 18,000 km^2 and contains about 9 km thick of Tertiary sediment. The trend of this basin elongates in northwest-southeast direction. The study area can mainly produce gas, condensate and oil from Miocene and Oligocene Units. The reservoirs in Oligocene Unit are thin-bedded lacustrine delta sands and bar sands inter-bedded with organic-rich shale that are fair quality. In Miocene Units, the reservoirs separate into two types: 1) regressive facies contain thick amalgamated alluvial and fluvial channel sands that represent excellent reservoir quality and 2) transgressive facies comprise of thin bar, point bar and distributary channel sands (Chuachomsuk and Noosri, 2012).

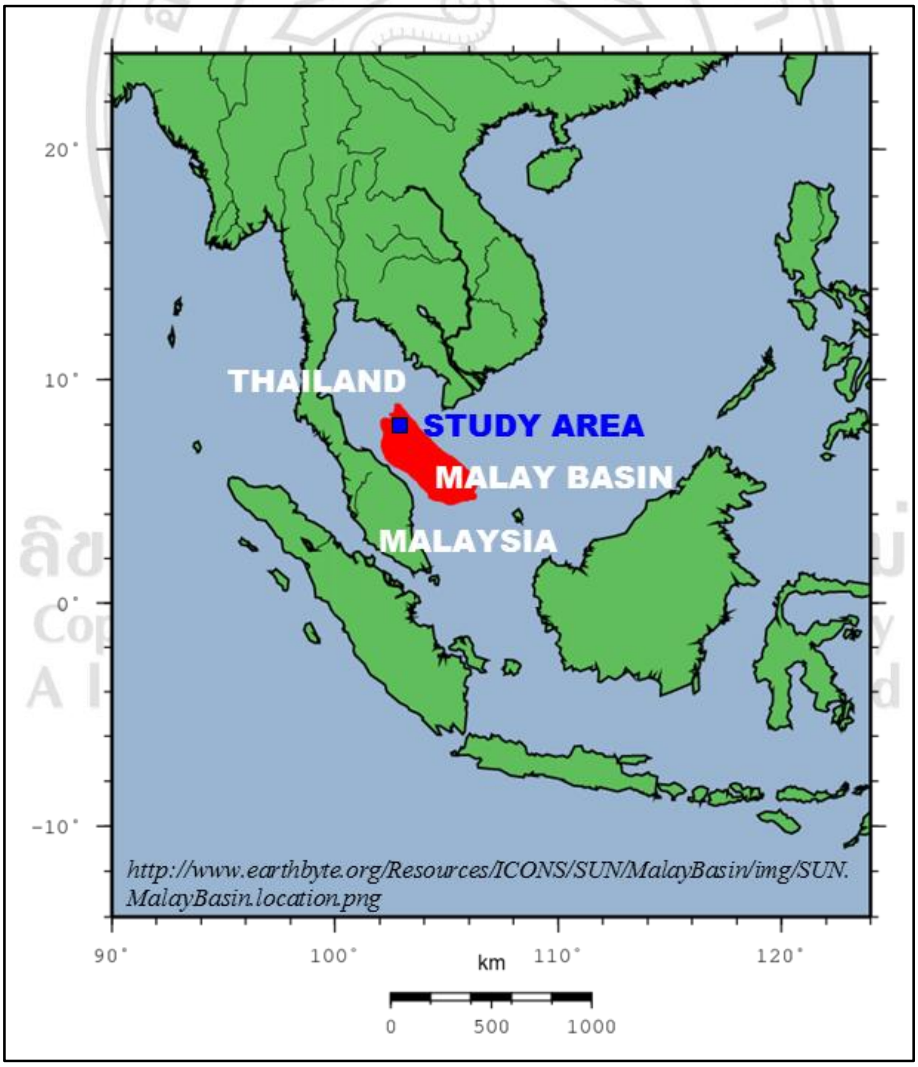

Figure 1-1. Location of study area in North Malay Basin (Heine, 2008)

1.2.1 Basin Configuration

The North Malay Basin is an intracratonic basin which is located in the Gulf of Thailand. This basin was formed by early Tertiary rifting along N-S and NW-SE trends. The geometry of this basin was controlled by the series of N-S normal fault and NW-SE strike-slip fault (Figure 1-2). The width of North Malay Basin is of approximately 100 km, about 220 km in length and depth varies from high basement (~1600 m), ramping area to deep basin depo-center (>8000 m).

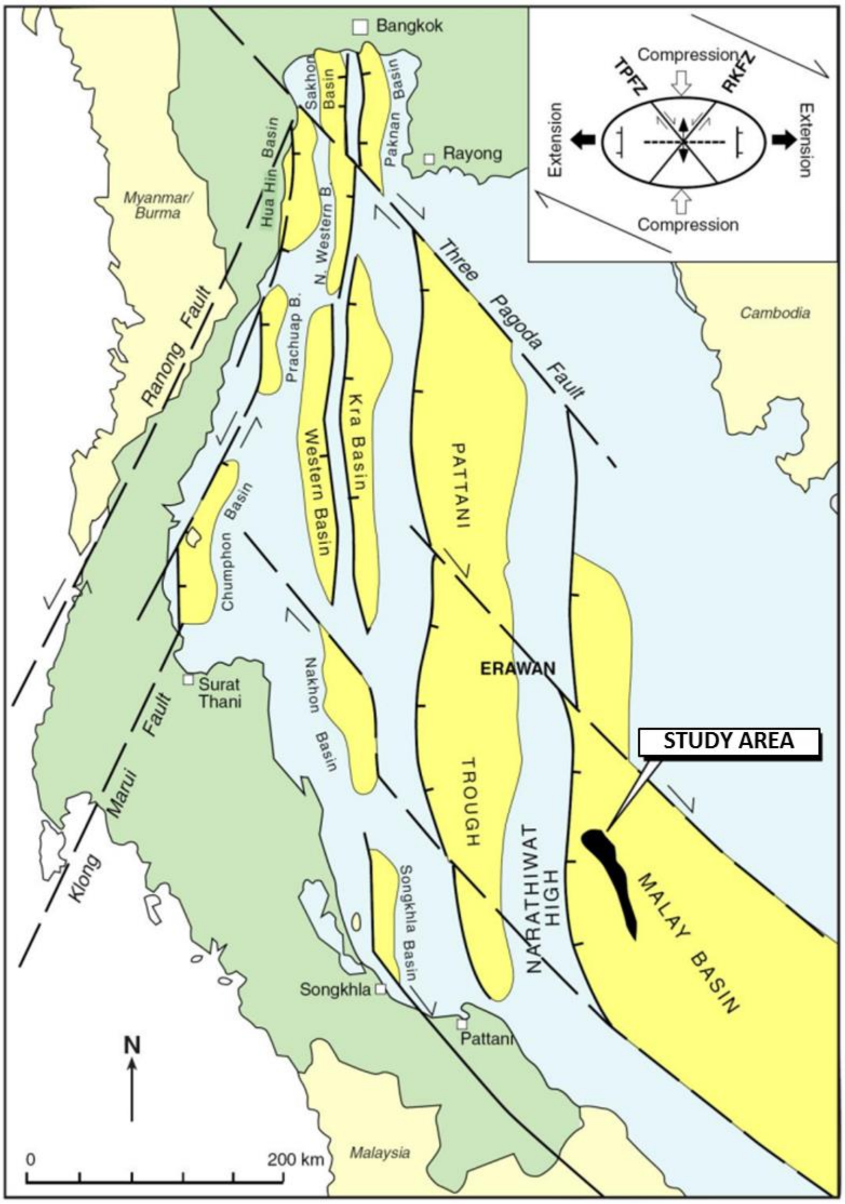

Figure 1-2. The regional fault trends of the Tertiary basins in the Gulf of Thailand (Polachan et al., 1991)

1.2.2 Stratigraphy of the North Malay Basin

The stratigraphy of the North Malay Basin was controlled by tectonic evolution, trangressive cycles, regressive cycles and syn-depositional faulting. It is quite similar to other basins in this region and depositional environment ranges from fluvio-lacustrine to lower delta plain margin. Stratigraphic sequence of the North Malay Basin can be described from base to top as follows and Figure 1-3.

Basement (Pre-Tertiary Unit) is all rocks which are older than Formation 0 (Fm0). It is separated from Fm0 by Pre-Tertiary Unconformity that represents a hiatus at least 35 Ma. This unit composes of late Mesozoic granite or late Paleozoic sedimentary rocks which are a highly dipping bed series of siltstone, shale and occasional sandstone.

Formation 0 (Fm0) is assumed to be Oligocene Age. It was formed in the initial syn-rift to early post-rift phase and was deposited by fluvio-lacustrine sediments. The lower part of this unit composes of sediments that was dominated by lacustrine and alluvial fan system. The sediment accumulation is coarse sand and conglomerate along active margin of half graben. Lacustrine environment deposited carbonaceous shale which is rich in Type II kerogen. The upper part represented lacustrine and fluvio-lacustrine sediments that accumulated shale and thin bedded sandstone which are fine grained and coarsening upward sequence. This unit is an important source rock for the deep petroleum system in the North Malay Basin.

Formation 1 (Fm1) is early Miocene when the basin was suffering thermal subsidence in early post-rift phase. Depositional environment was dominated by fluvial systems. The lithology composes thick bedded medium to coarse-grained sandstones and good sorting inter-bedded with red oxidized claystones and siltstones representing to regressive sequence. This unit is a high quality reservoir for the deep petroleum system in the North Malay Basin.

Formation 2 (Fm2) represents the period for a series of transgressive and regressive cycles influencing by a local marine setting in Miocene age. Depositional environment is range from fluvio-tidal/delta, delta plain to delta front in the marginal marine. It can be subdivided into 5 units, from oldest to youngest as 2A, 2B, 2C, 2D and 2E. Unit 2A is a transgressive sequence of fine to medium sandstone inter-bedded with brown to gray claystone and coal beds (Type III kerogen). It is a main source rock and reservoir of the shallow petroleum system. Unit 2B represents to sand-rich regressive sequence including thick bedded sandstones, isolated channel sandstones and organic rich shale. This unit is a major reservoir of shallow petroleum system. Unit 2C is a shale-rich regressive sequence and includes coals, carbonaceous shale, coaly shale and very fine to fine-grained sandstone. Unit 2D is a regressive sequence including meandering stream sandstones, delta channel/bar sandstones and thick bedded coal. This unit is high quality reservoir. Unit 2E represents to sand-rich regressive sequence that composes of thick bedded sandstones related to amalgamated distributary channels and bars. It is a good reservoir.

Formation 3 (Fm3) is in late Miocene to Recent during the regional sagging phase. The sedimentation was controlled by tidal plain to shallow marine. Lithology consists of thick bedded sandstones which are medium to coarse-grained sands and good sorting inter-bedded with red oxidized claystones and siltstones.

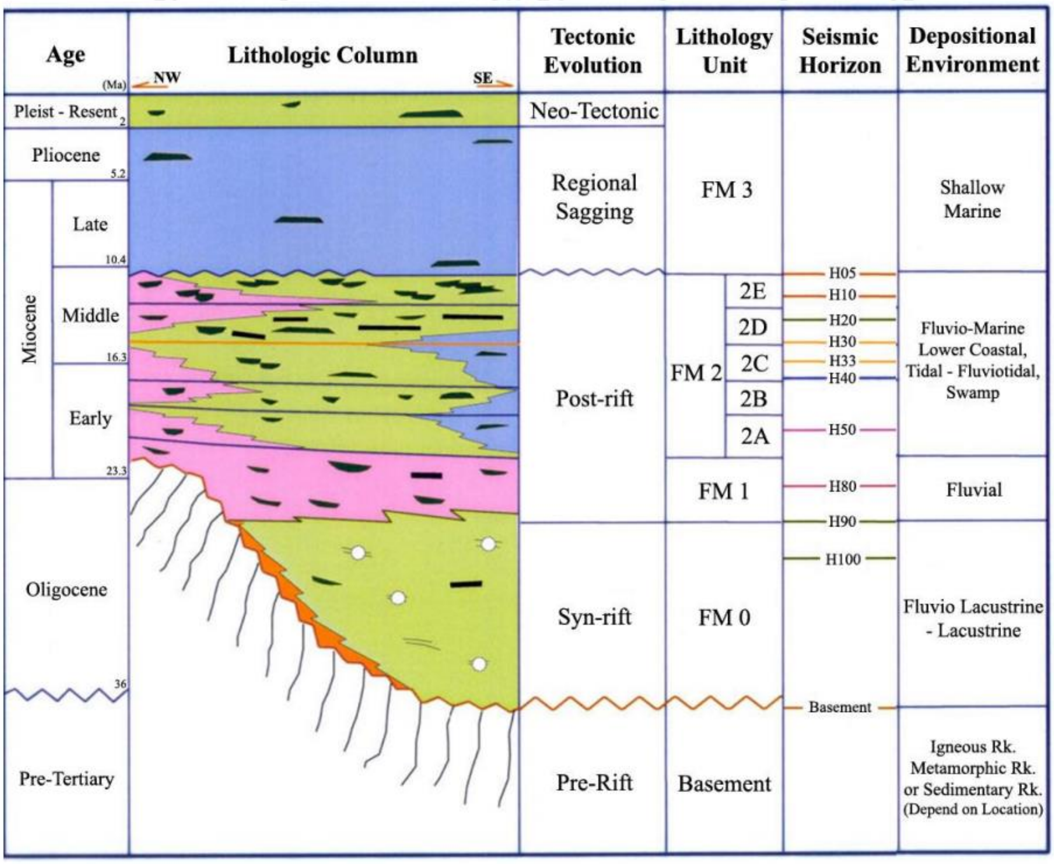

Figure 1-3. Regional schematic stratigraphy of the North Malay Basin (modified from Intharawijitr and Triamwichanon, 1998).

1.3 Objective

To delineate the lithology of Miocene and Oligocene Units using pre-stack deterministic inversion

1.4 Literature Review

1.4.1 Rock Physics Inversion

A Montney case study was applied for generating petrophysical property volumes in a Montney tight gas play. This rock physics inversion method has been applied in high porosity and offshore environment with great success of petroleum exploration (Westang et al, 2009).

In the same Montney area, generation of AVO inversion was carried out simultaneously on multiple angle stacks to accurately compute elastic rock property volumes such as acoustic impedance, V_P/V_S, and density. Then, rock physics inversion was analysed to characterize tight gas plays relating the elastic rock properties using well logs and other available information. The good match between the inversion results and the well logs suggested the inversion results are reliable (Figures 1-4 and 1-5). Based on these results, the target zone of a Montney was altered (Johnson at el., 2014).

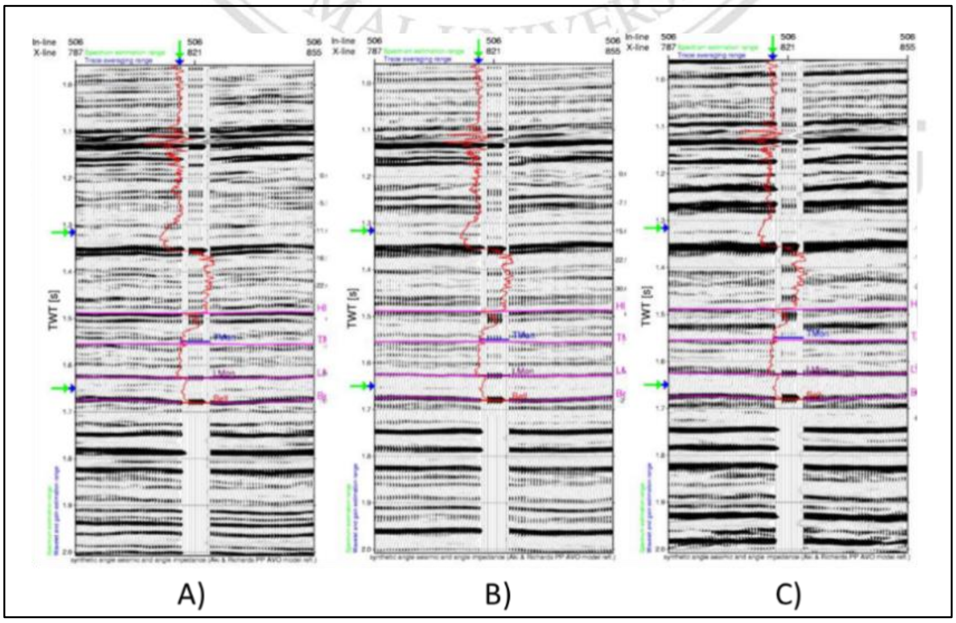

Figure 1-4. Well tie of variable angle stacks: A) The 5-15 degree angle stack, B) The 15-25 degree angle stack, and C) The 25-40 degree angle stack (Johnson at el., 2014)

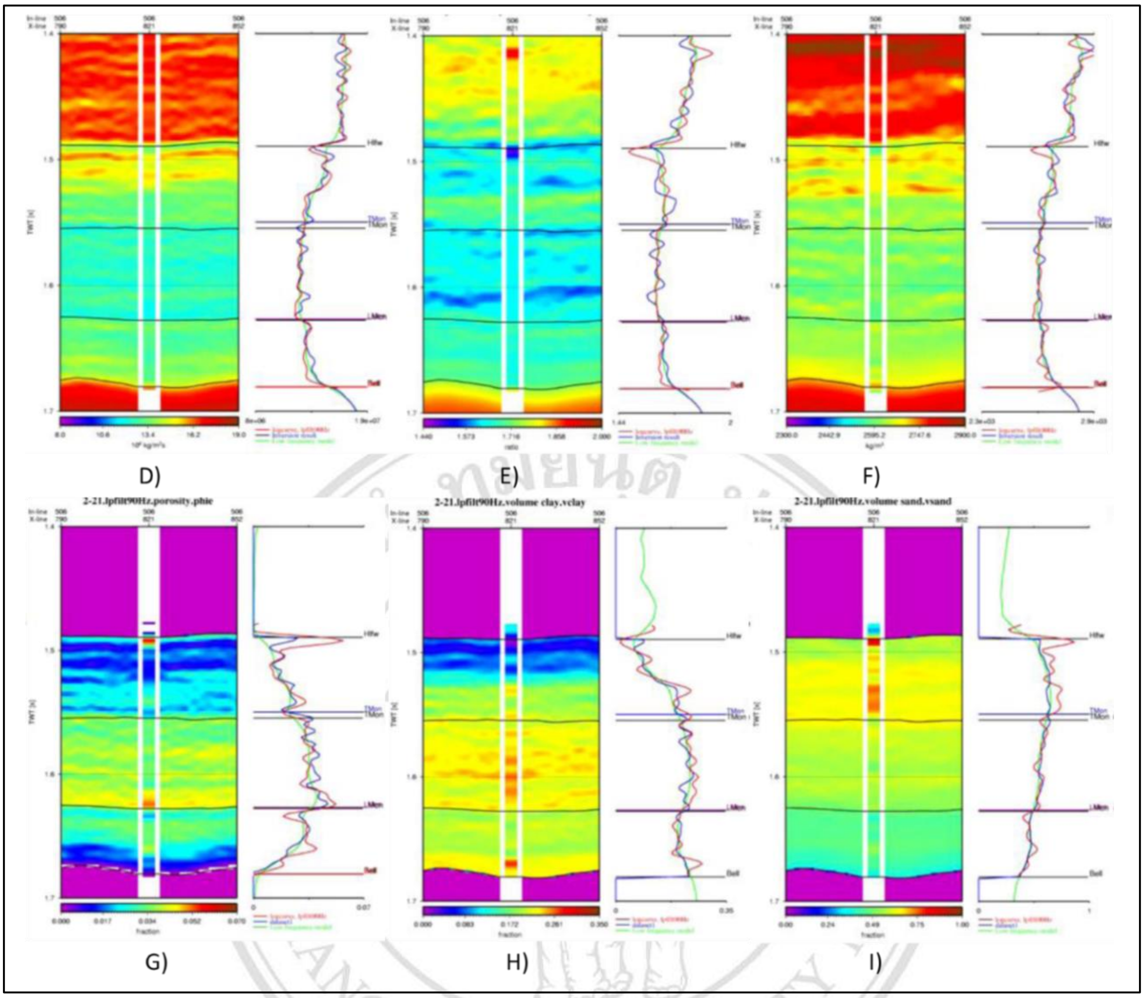

Figure 1-5. AVO inversion results and rock physics inversion results for well 2-21 of A Montney case study: D) AI inversion result, E) Vp/Vs ratio inversion result, F) Density inversion result, G) Porosity inversion result, H) Volume of clay inversion result, and I) Volume of sand inversion result (modified from Johnson at el., 2014)

However, the lithology, geological setting and goals of the Montney study are very different from the study area. This case is an example of good quality results to evaluate the inversion results comparing to well log interpretation, so the good match between the inversion and the well logs suggests the inversion results are reliable.

1.4.2 Pre-stack Inversion for Estimating Rock Properties

Applying pre-stack simultaneous seismic inversion is generally possible to estimate shear impedance, V_P/V_S or Poisson's ratio from acoustic impedance with the same resolution, even though these properties are decreased their resolution relating to the far-offset seismic data. Furthermore reliability of the estimated density which can be derived from the seismic data has proven very useful in prediction of certain lithology and saturation (Maver and Rasmussen, 2004).

Anderson (2009) discussed in reservoir quality within Mannville-age fluvial channels by reviewing and comparing the post-stack and pre-stack inverted method. Both of them were applied for estimating rock properties and given a specific exploration or development goal. Based upon the results, the pre-stack inversion is the best method to estimate V_P/V_S from seismic data. It was revised the processing of the P-wave seismic data to incorporate further offsets/angles to be angle gathers. This help to constrain the inversion results.

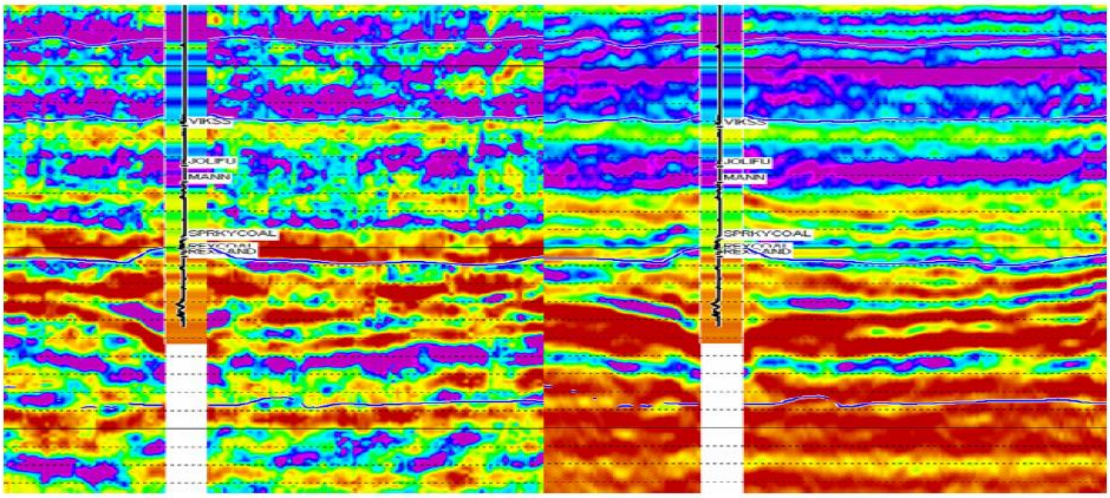

Figure 1-6. Comparison of V_P/V_S calculated from AVO + post-stack inversion (left), pre-stack inversion (right). V_P/V_S from logs at Well D had been inserted in colour and the SP log as the trace. (Anderson, 2009)

1.5 Data Available

1.5.1 Well Log Data

Four exploration/appraisal wells (D-36, S-2, R-2 and D-29) are available in the area. Information of the wells was included well logs, geological markers, checkshot data and final well reports. The well logs are wireline logs consisting of gamma ray, sonic, shear sonic, density, neutron porosity and resistivity logs (Figures 1-7 to 1-10). The well locations are shown in Figure 1-11.

Normally, sonic and shear sonic logs are acquired in slowness unit (μs/ft or microsecond per foot) along measuring depth (MD). However, both sonic logs should be converted to velocity log (m/s or meter per second) for applying to other usage. In RokDoc software, sonic and shear sonic logs can be converted to P-wave and S-wave velocity log (V_P and V_S), respectively, during imported process.

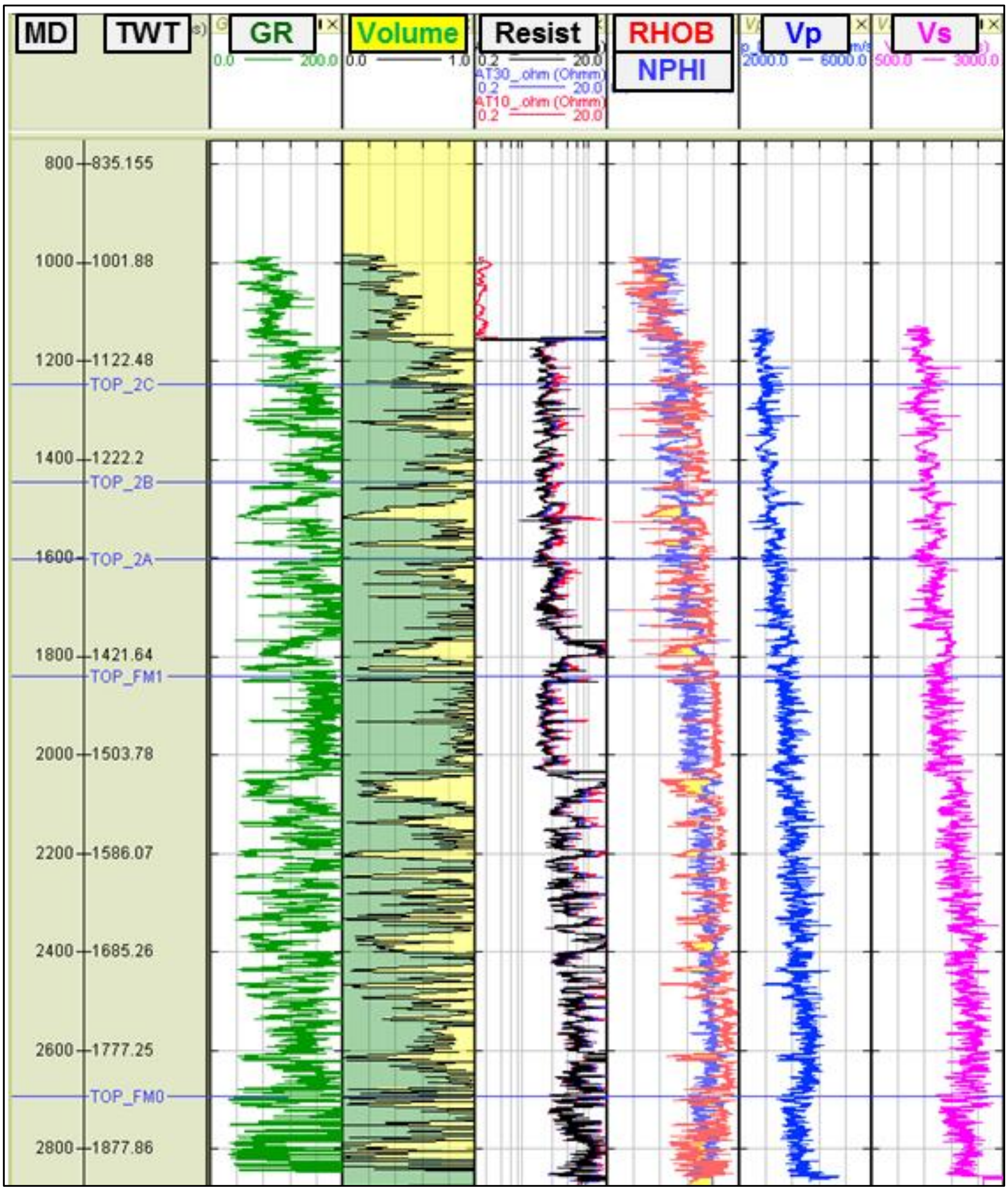

Figure 1-7. Well logs and geological markers of R-2 Well, approximately acquired interval of gamma ray, neutron porosity and density logs is 1000 – 2850 mMD, interval of resistivity log, sonic (V_P) and shear sonic (V_S) logs is 1140 – 2850 mMD.

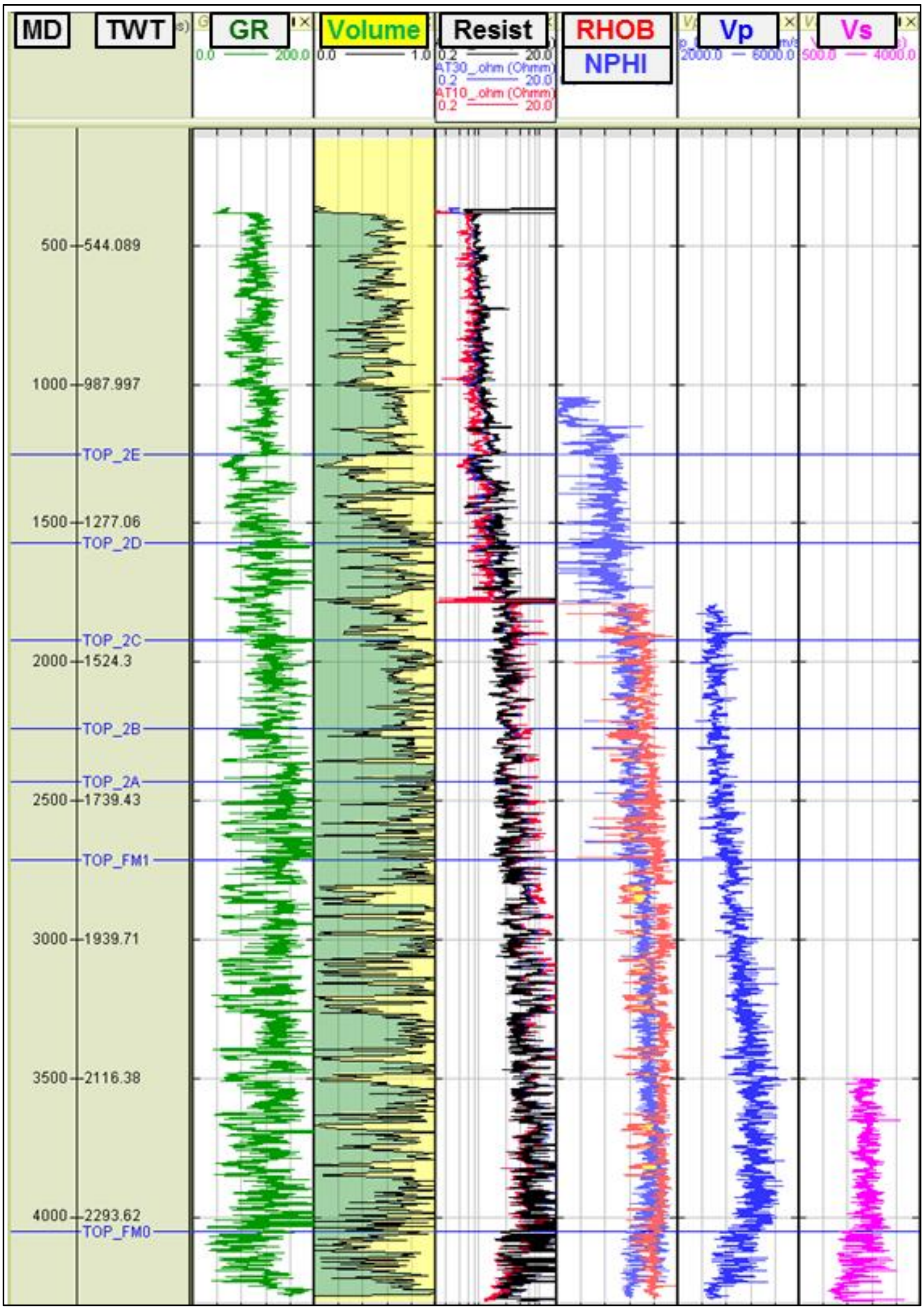

Figure 1-8. Well logs and geological markers of D-36 well, approximately acquired interval of gamma ray and resistivity logs is 370 – 4300 mMD, interval of neutron porosity log is 1050 – 4300 mMD, interval of density and sonic (V_P) logs is 1800 – 4300 mMD, and interval of shear sonic (V_S) log is 3500 – 4300 mMD.

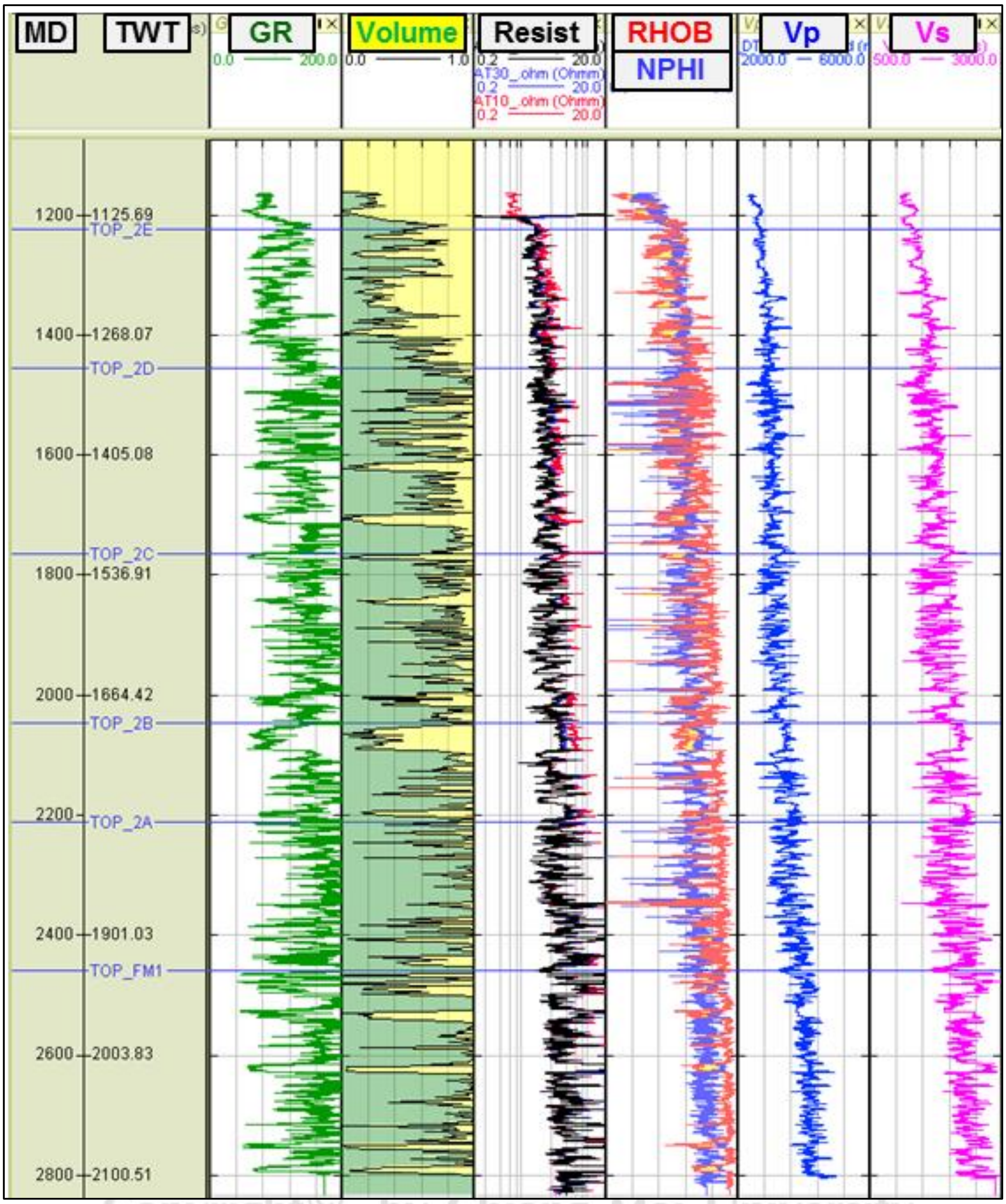

Figure 1-9. Well logs and geological markers of S-2 Well, approximately acquired interval of gamma ray, resistivity, neutron porosity density, sonic (V_P) and shear sonic (V_S) logs is 1160 – 2830 mMD.

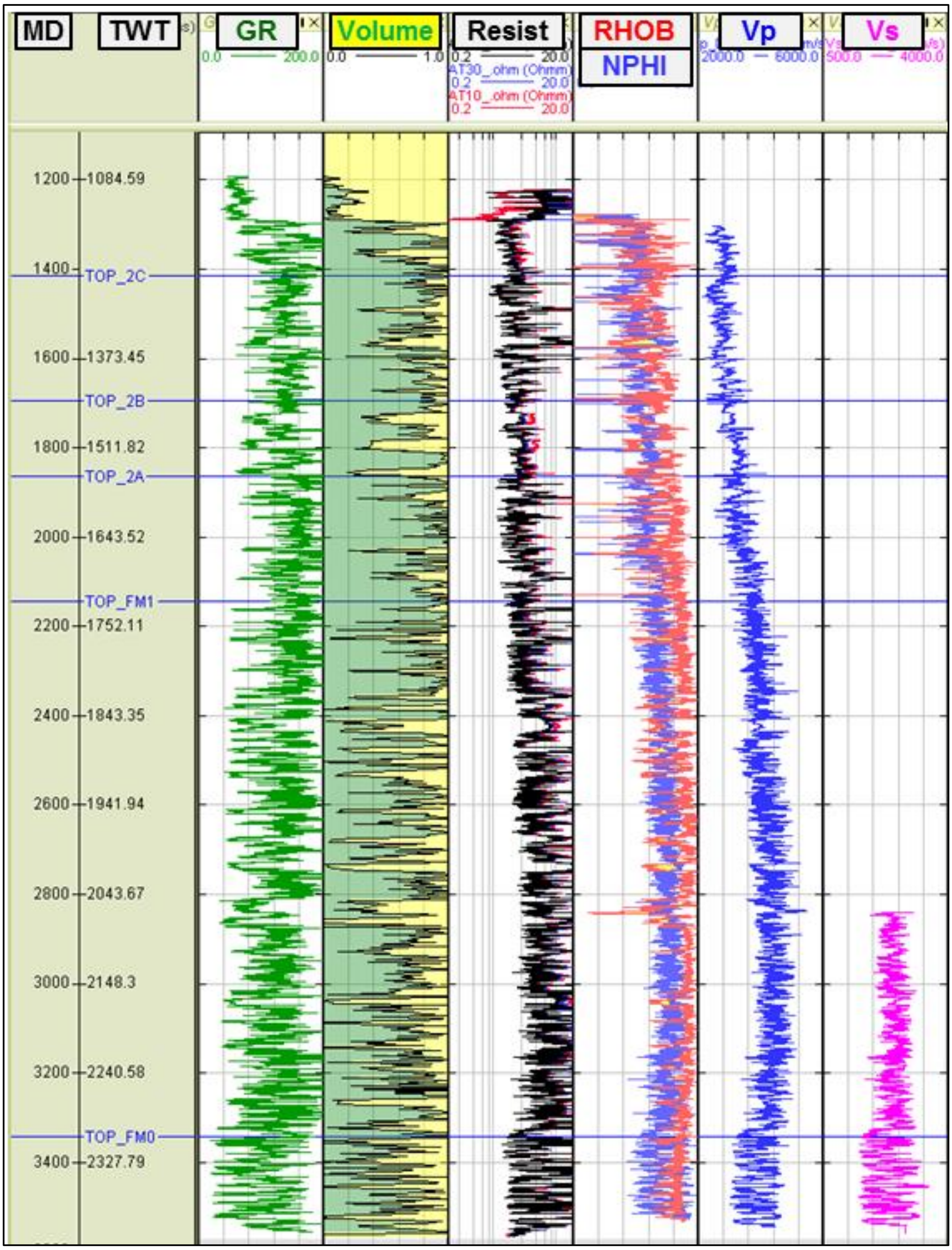

Figure 1-10. Well logs and geological markers of G-29 Well, approximately acquired interval of gamma ray and resistivity logs is 1200 – 3560 mMD, interval of neutron porosity, density and sonic (V_P) logs is 1280 – 3560 mMD, and interval of shear sonic (V_S) log is 1140 – 3550 mMD.

1.5.2 Seismic Data

Seismic data of the study is 3D pre-stack seismic data covering an area of approximately 670 km^2 (Figure 1-11). It was acquired by Geco-Prakla in 1997 and reprocessed by CGGVeritas in 2007. The data comprised 1213 line gathers (Inline range 16 – 1258) and 2001 crossline gathers (Crossline range 1800 – 3800). The seismic reprocessing data produced the pre-stack migrated gathers which were applied Kirchhoff PSTM and NMO correction using residual velocity. Examples are illustrated in Figure 1-12. The purpose of reprocessing is to obtain a high quality pre-stack dataset which will subsequently be used for structural, stratigraphic and quantitative interpretation. The output CDP gathers will be used for detailed AVO analysis and should be multiple free, amplitude preserved and reflection events flat to the farthest offset possible. The seismic acquisition and processing parameters are represented in Appendix.

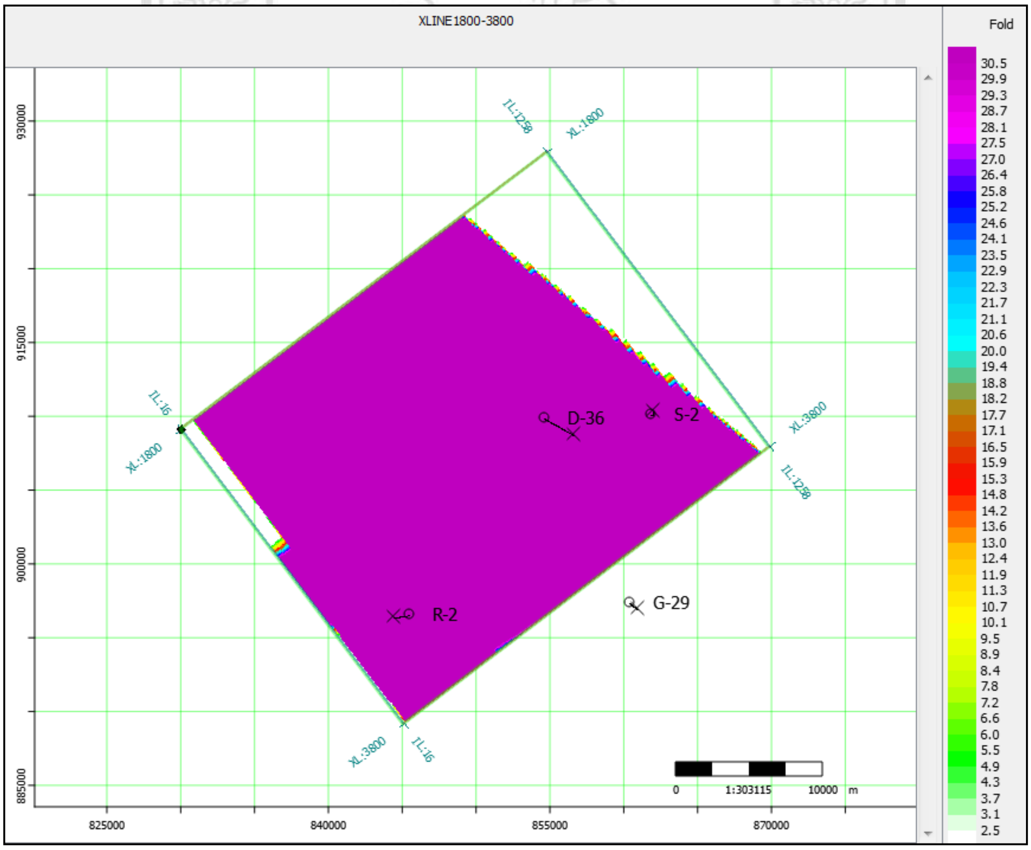

Figure 1-11. Well locations and seismic area which is filled by color bar of fold (maximum fold is 32) is 3D pre-stack seismic gathers combining to a 3D survey.

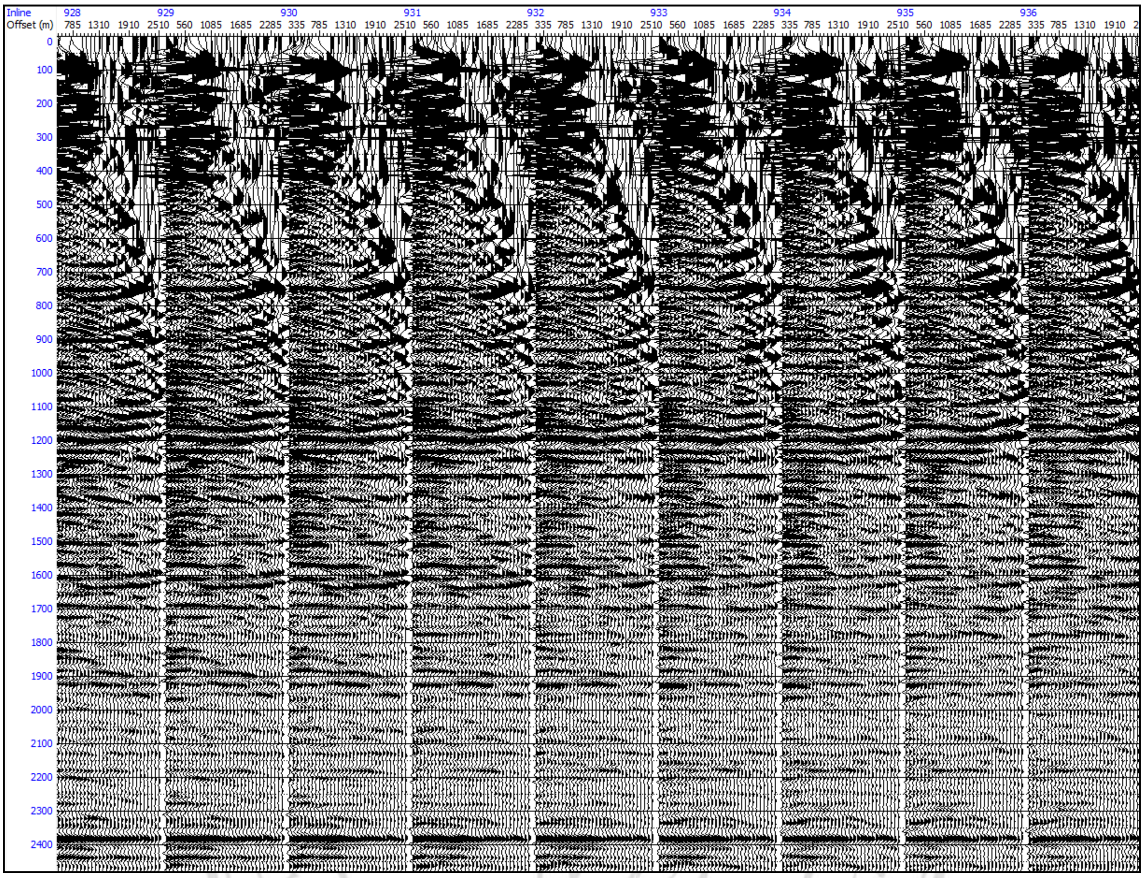

Figure 1-12. Examples of pre-stack seismic data on Inline 1900 after NMO correction from an early step in processing

1.5.3 Interpretation Data

There are eight seismic horizons and several faults were interpreted in this area using 3D seismic volume. The interpreted horizons which are Horizon O, L, U, A, B, C, D and E from old to young age (Figure 1-13) can be correlated to geological markers following stratigraphy sequence in topic 1.2.2 as represent in Table 1-1. However, the horizons and correlative markers may not be located exacting time and depth because they are interpreted in different domain (horizons in time and markers in depth) and assumed to match nearby them.

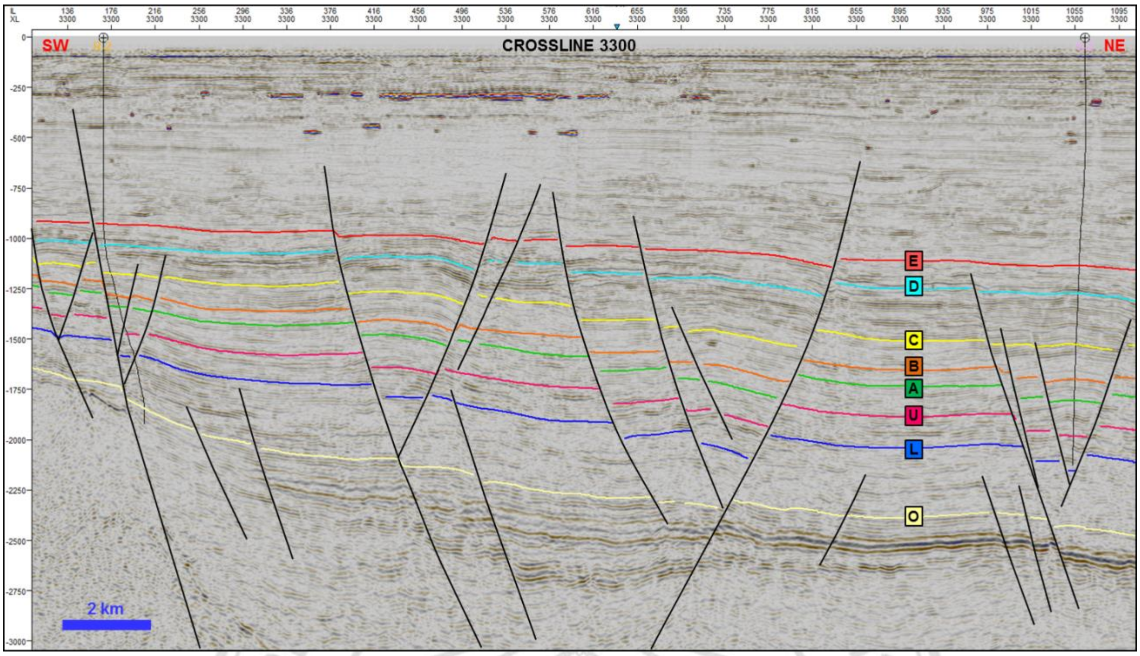

Figure 1-13. Seismic section show interpreted horizons and faults in study area.

Table 1-1. Relationship between interpreted horizons and geological markers

Horizon	Correlative Geological Marker (Top Age)
E	Top Formation 2 (Top Middle Miocene)
D	Top Unit 2D
C	Top Unit 2C
B	Top Unit 2B (Top Early Miocene)
A	Top Unit 2A
U	Top Upper Formation 1
L	Top Lower Formation 1
O	Top Formation 0 (Top Oligocene)