



Fracture Detection with Azimuthal Seismic Data, Rock Physics, and Geomechanics

A Thesis submitted in fulfilment of the requirements for the degree of

Doctor of Philosophy

José Alfredo Guerrero Castro

St Peter's College

Hilary Term 2023

Supervisor: Professor Joseph Cartwright

Department of Earth Sciences

University of Oxford

DEDICATION

So much of what I am traces back to my lovely wife Marvilla, daughter Nina and my son Jacob, father, brothers, and sisters who have made many sacrifices to help me be here. In loving memory of my mother Bernabé Castro, my niece Julia Guerrero, my brothers José Luis, and Francisco. Thank you.

DECLARATION OF AUTHORSHIP

I, José Alfredo Guerrero Castro, declare that the thesis entitled, “FRACTURE DETECTION WITH AZIMUTHAL SEISMIC DATA, ROCK PHYSICS AND GEOMECHANICS” and the work presented in it are my own. I confirm that:

- This work was done wholly or mainly while in candidature for a research degree at this University.
- Where any part of this thesis has previously been submitted for a degree or any other qualification at this University or any other institution, this has been clearly stated.
- Where I have quoted from the work of others, the source is always given. Except for such quotations, this thesis is entirely my own work.
- I have acknowledged all main sources of help.
- Where the thesis is based on work done by myself jointly with others, I have made clear exactly what was done by others and what I have contributed myself.

Signed:

A handwritten signature in blue ink, appearing to be 'José Alfredo Guerrero Castro', is written over a horizontal line. The signature is stylized and extends above and below the line.

Date:

“Remember to look up at the stars and not down at your feet. Try to make sense of what you see and wonder about what makes the universe exist. Be curious. And however difficult life may seem, there is always something you can do and succeed at....”

[Stephen Hawking]

Abstract

Significant progress has been made for fracture detection in unconventional plays using advanced geophysical techniques such as the use of P-wave AVO algorithms in multi-azimuth data. In the past decade, it has been recognised that major amplitude distortions in anisotropic media occur, for wide-azimuth data, and that these might potentially be related to fracture distribution in the layered media. However, inversion of the azimuthally varying P-wave AVO gradient for the crack density is non-unique without additional information.

Aims

This research work aims to better understand the seismic anisotropy of shale rocks to improve future exploration by using fracture modelling and azimuthal AVO/AVA for fracture detection, and rock physics to develop a thorough understanding of the reservoir and quantify fracture anisotropy quantitatively and qualitatively. This is a potentially important unconventional oil and gas reservoir of the Late Jurassic age. Specifically, the project aims to improve future oil exploration by using AVAz variations for fracture detection and fracture models in effective media.

Scope

The scope of this research is to model fractures of the effective medium to see the impact on seismic amplitudes distortions in different azimuthal directions and determine the type of AVO present in the models to compare them with real data in shale-type rocks. Implementation is presented of a new methodology to estimate anisotropic brittleness, the azimuthal TOC and stress field and its comparison with hydraulic treatment pressure data, calculated from inverted volumes with good quality azimuthal seismic data. Rock physics and fluid replacement in fracture models in shale rocks approaches will be tested for (brine/oil/gas) to better understand the fluid substitution in azimuthal synthetic models and the AVAz curves.

Motivation

The motivation for this work is to develop a better understanding of the anisotropy within the Pimienta Formation, which will help understand the shale-type rock fabric through fracture modelling, azimuthal data for better reservoir characterization in unconventional reservoirs.

Methods

Based on the effective media theory of fracture models addressed by other researchers, codes were developed and tested to obtain an azimuthal seismic image depending on the type of fracture arrangement (e.g., Hudson, and Linear slip). Within the methodology, in the substitution of fluids, the Linear slip model was tested to verify the synthetic azimuthal response with three cases (Brine/Oil/dry). Azimuthal seismic information provided by PEMEX was used to perform AVO Azimuthal analysis within the Pimienta Formation in order to identify possible fracture swarms and be able to determine the direction of the fast velocity (V_{fast}) that is related to the direction of fractures and possible current stress. Then rock physics modelling of elastic moduli in an anisotropic way was estimated by developing codes to obtain brittleness, these elastic moduli (e.g., Young's Modulus and Poisson's Ratio) were used to estimate the stresses in a sub-area in the study area using inverted volumes. Differential Effective Medium (DEM) and Effective Field Method (EFM) have been tested in the study area to estimate the elastic moduli.

Results

The Pimienta Formation in rock physics template analysis fit much better using friable-sand model instead of friable shale model, different values in anisotropy within Pimienta Formation were found according to the significant amplitude distortions seen in each fracture model which may explain the intrinsic anisotropy of the Pimienta Formation. The azimuthal AVO demonstrated the possible existence of fractures within the Pimienta Formation in the study area according to the differences in the fast velocity (V_{fast}) and slow velocity (V_{slow}) and the Thomsen's parameters, the fluid-filled fracture models through fluid substitution analysis in shale rocks demonstrated amplitude changes depending on the azimuth direction. The elastic properties

(e.g., Young's Modulus and Poisson's Ratio) were estimated in VTI/HTI modes using the inverted data and finally the stress field using hydraulic treatment pressure information.

Conclusions

In this research work, two main contributions can be addressed that may help other geoscientists for a better understanding of the anisotropy in shale rock type and can be widely applied for reservoir characterization on unconventional resources in other projects around the world and maybe applied naturally fractured carbonates.

1. A new equation for estimation of the TOC in different azimuths named “upscaled azimuthal TOC” using inverted data from azimuthal seismic data contributed to the novel implementation of the calculation of this attribute which had been experimentally tested on core analysis in different azimuths.
2. A novel approach for the estimation of anisotropic brittleness has contributed to the field of anisotropy on shale rock types by using vertical transverse isotropy (VTI) and horizontal transverse isotropy (HTI) using azimuthal sectors of inverted seismic information.
3. For this research project, applications were developed in the field of geophysics that addressed fractured models (e.g., Hudson, and Linear slip), anisotropic rock physics for the calculation of elastic properties in two main directions 0° (VTI) and 90° (HTI) for the calculation of anisotropic brittleness compared with other researchers in this field. Such applications can help the geoscientific community to model fractures in effective media in a versatile and easy to use way since most software does not handle this type of modelling.
4. These new contributions in geophysics applied to the oil industry were focused on the study of the Pimienta Formation; however, these contributions can be widely used in the development, understanding and characterization of unconventional and carbonate reservoirs around the world.

Finally, these contributions and all the analysis carried out in this research work will contribute to more efficient stages design for hydraulic treatment in horizontal wells in unconventional reservoirs, in order to reduce operating costs and the number of wells with the objective of obtaining the highest possible commercial production of hydrocarbon without ignoring the environmental impact and concerns.

Acknowledgements

I would like to thank Professor Joseph Cartwright for his extraordinary supervision and generous help in the development of this DPhil research. Special thanks to PhD. Martino Foschi, who supervised me and his continues help and support during my stay at University of Oxford at the Earth Science department to study contributions that would benefit in the successful completion of this thesis and Professor Gary M. Mavko at Stanford University for his recommendation to address part of this research work. I also want to thank M.Sc. Damaso Contreras Tebar from PEMEX E&P for his supervision. Thanks are extended to my sponsors CONACYT-SENER and PEMEX E&P for giving me the scholarship for the completion of my DPhil I also want to thank PhD. Mikhail Markov, PhD Ambrosio Aquino López and PhD Marytere Gutierrez Guevara from Mexican Institute of Petroleum (IMP) and PhD Ricardo Zavala Torres from Schlumberger for their guidance to tackle the effective field method (EFM) and (DEM) approach. Special thanks go to Ing. Antonio Escalera Alcocer, PhD. Ulises Hernández Romano CEO at PEMEX PMI, Ing. Leonardo Enrique Aguilera Gomez, Ing. Lauro Velazquez Contreras, PhD. Juan Rogelio Roman Ramos, Ing. Enrique Escobar Hernandez, Ing. Luis Ricardo Caraveo Miranda, and Erika Carmona Castañon for their administrative support during my DPhil. I also wish to thank Michel Kamper from IKON Company in London for providing RokDoc license to use Blocky OPS toolkit that was needed for this thesis. As well as thanks to CGG Company to provide Hampson and Russell Software to support my DPhil. Thanks to Karina Uribe Trejo, José Jonathan Jasso Saldaña, Mario Alberto Porras Vazquez, Sergio Perez López, José David López Garcia, Luis Antonio Valdes Bernal and in loving memory of Marco Antonio Garcia Ortega from PEMEX E&P. Thanks goes to PhD. Gabriel Chavez Cabello from FCT/UANL for his guidance during the field trip to collect samples of La Casita Fm in Iturbide NL Mexico and their kindness help and support to gather and provided all the information for this dissertation and also wish to thank José L. González Navarro at Petricore for his support on rock mechanics analysis. I am heartily thankful to my wonderful friends in Oxford, namely, Cesar Espinoza Campuzano, Felipe de la Parra, May Chung from Shell

Group: Victoria Elliot, Chis Kirkham, James King, Claudia Bertoni, Matteo Paganoni, Benedict Campbell, and Micheal Struggale for the great moments that I lived in the group also thanks to my officemates Lauren O'Connor, Annika Voigt, Anna Brookfield, Matthew Jerram, Richard Thomas and Andrew Orkney. My deepest gratitude goes to God, my wife Marvilla J. Cantú López, my daughter Nina A. Guerrero Cantú, my son Jacob Guerrero Cantú and my parents for their caring, loving and understanding. Finally, I am grateful to the Earth Sciences Department of the University of Oxford and St. Peter's College for giving me the opportunity to be part of this great institution of which I am very proud.

Table of Contents

1. Introduction	1
1.1 What is a fracture?.....	2
1.1.1 Scale of fractures	4
1.2 Geophysical description	5
1.3 Background to this study: Recent research on fracture detection using geophysical methods.	15
1.4 Unconventional Reservoirs	17
1.4.1 Total Organic Carbon (TOC)	24
1.4.2 Brittleness.....	25
1.4.3 Importance of fractures in unconventional plays in the oil and gas industry	28
1.5 Rationale, Scope, Aims and Execution	28
1.6 Layout	30
2. Geological Setting	32
2.1. Introduction	33
2.2. Tectonic setting/evolution.....	34
2.3. Stratigraphy	40
2.4. Geochemistry of the Pimienta Formation	48
2.5. Exploration History	49
2.6. Petroleum system	52
3. Data, methods, and dataset preparation.....	54
3.1. Introduction	55
3.2.1 Azimuthal data offset vector tile (OVT)	59
3.2.2 Seismic to well calibration	63
3.3 S wave log prediction.....	72
3.4 Conventional TOC estimation and rock brittleness	76
4. Fracture models in effective media	87
4.1. Introduction	88
4.1.1 Anisotropic symmetry classes, particularly the relevance of orthorhombic symmetry to fractured shales.....	89
4.2. Data and methods	97
4.2.1 The Hudson Model.....	101
4.2.2 Schoenberg linear-slip model.....	103
4.2.3 Eshelby-Cheng model	104

4.2.4 Assumptions and limitation, models Ruger Thomsen and Backus Averaging	105
4.2.4.1 Thomsen model.....	109
4.2.4.2 Backus Average.....	110
4.2.5 Blocky Ops.....	113
4.2.6 Fracture density <i>Bani</i>	114
4.3 Results	115
4.3.1 The Hudson Model.....	116
4.3.2 Schoenberg linear-slip model.....	120
4.3.4 Blocky Ops wave field and fracture density <i>Bani</i>	129
4.3.5 Links and comparisons between the various fracture models, interpretation of fracture compliances in the linear slip theory	149
4.3.6 Discussion of the link between the <i>Bani</i> parameter and non-fracture rock properties, as discussed in the literature.....	158
4.4 Discussion	162
4.4.1 Fractured model limitations	165
4.5 Conclusions.....	166
5. Fracture detection using azimuthal AVO and rock physics	168
5.1. Introduction	169
5.2. Data and methods.....	175
5.2.1 AVAz application within Pimienta Formation.....	176
5.2.2 Microseismic monitoring (Analogue well within Pimienta Formation)	181
5.2.3 DEM approach and detailed comparison with the literature on shale modelling.....	189
5.2.4 Anisotropic rock physics	205
5.2.5 Effective field method (EFM) within Pimienta Formation	224
5.2.6 Description of how attributes were extracted from the data.....	232
5.3. Results	240
5.3.1 AVAz fracture density <i>Bani</i> attribute from azimuthal seismic data within Pimienta Formation	240
5.3.2 Fracture modelling and AVAz comparison.....	246
5.3.3 Microseismic, structural attribute and AVAz combination.....	249
5.3.4 Fluid effect in anisotropic rocks.....	254
5.4. Discussion	262
5.4.1 Fracture detection using AVAz within shale Pimienta Formation.....	262
5.4.2 AVAz and rock physics limitations.....	268
5.4.3 Discussion of the concept of anisotropic brittleness- what does this really mean and the limitations of the brittleness index	269
5.4.4 Differential effective medium (DEM).....	276

5.4.5 Effective field method (EFM)	277
5.5. Conclusion.....	277
6. A novel approach to estimate TOC/Brittleness and stress field using seismic inversion based on azimuthal data	279
6.1 Introduction	280
6.1.1 Aims	281
6.1.2 Phase of a seismic wavelet (seismic inversion).....	282
6.2 Data and methods	289
6.2.1 TOC.....	294
6.2.2 Static Young's Modulus.....	295
6.2.3 Anisotropic brittleness (0° and 90°) in four different azimuths	296
6.2.4 Stress field.....	298
6.3 Results	308
6.3.1 Well trace inversion	310
6.2.3 Azimuthal estimation of TOC from inverted seismic data.....	311
6.2.3 Anisotropic Young's Modulus and Poisson's Ratio	317
6.2.3 Anisotropic brittleness (<i>BritV</i> and <i>BritH</i>)	321
6.2.4 Stress field.....	323
6.4 Discussion	333
6.4.1 TOC calculation in different azimuth sectors based on inverted data.....	333
6.4.2 Correction of elastic properties	334
6.4.3 Anisotropic brittleness (<i>BritV</i> and <i>BritH</i>).....	335
6.4.4 Stress field and DHSR.....	335
6.4.5 Attribute extraction on TOC and Brittleness.....	336
6.5 Conclusions	338
7. Discussion	339
7.1. Introduction	340
7.2. Summary of key findings	341
7.3. Comparison with other studies on fracture models and effective medium	347
7.5. Young's Modulus, Poisson's Ratio, brittleness and Stress field.....	351
7.6. General contributions of this research work.....	352
7.7 Limitation and step forward	356
8. Conclusions	358
8.1. Introduction.....	359
8.2. Fracture models.....	361
8.3. Differential effective medium (DEM).....	362

8.4. Effective field method (EFM)	362
8.5. Brittleness calculated in different directions	362
8.6 TOC calculated in different azimuth direction.....	363
Reference.....	365
Appendix A	386
A.1 CRACKEDMED.....	387
A.2 FRACKMED.....	388
A.3 ModAz.....	391
A.4 Baniz.....	397
A.5 Blangy Model modified.....	402
Appendix B	407
B.1 DEMmodR1.m	408
B.2 FluidAnisoMod.m	429
B.3 BrittleAnisoMod.m.....	440
B.4 EFM equations of ellipsoidal inhomogeneity.....	444
Appendix C	447
C.1 StressMod.m.....	448

List of Figures

Figure 1.1 Natural fractures within Pimienta Fm from cores taken in the well Anhelido-1 (PEMEX E&P, 2012). The fractures are mineralised (veins) and are relatively sub-vertical and filled with calcite.

Figure 1.2 Design of sources and receivers in seismic acquisition and the effects of amplitude in the trace response through the angle of incidence.

Figure 1.3 AVO/AVA class representation chart, the first column of graphs represent the amplitude gradient curves depending on the AVO/AVA class, the second column is the crossplot of the top and base of the reservoir defining the type of AVO/AVA class and finally the third column the synthetic seismic response representation of each individual AVO/AVA class e.g. Class I starts with high amplitude and reduces with offset, Class II starts with low amplitude and increases with offset, Class III starts with high amplitude and increases further with offset, Class IV starts with high amplitude and decreases with offset.

Figure 1.4 A) Example of narrow common azimuth- versus B) Wide-azimuth templates and offset distributions. X offset distance in rose diagram.

Figure 1.5 A) VTI anisotropy parallel to the bedding and B) HTI is representing vertical fracturing orthogonal to the bedding in the symmetry of isotropic material.

Figure 1.6 Symmetry axis between VTI&HTI media.

Figure 1.7 AnisoMOD R1 user interface coded in MATLAB to compute the stiffness matrix for A) Anisotropic parameters in VTI; B) HTI media; C) Vp and Vs plot within Pimienta Formation (2113m).

Figure 1.8 Diagram of conventional reservoir and unconventional shale oil/gas reservoir in exploration.

Figure 1.9 (A) Schematic example of ‘fracking’ techniques on the shale reservoir; (B) Horizontal well with 17 hydraulic fracking stages at Anhelido-1H (PEMEX E&P, 2012) with ~1500 m length.

Figure 1.10. Workflow proposed to characterize and assess an unconventional reservoir in shale rocks in this project.

Figure 1.11 Shale plays in North America U.S.A (source U.S Energy Information Administration) based on data from various published studies.

Figure 1.12 The stress-strain curve showing typical yield for brittle materials (blue) compared with ductile materials (red). Stress (σ) is shown as a function of strain ϵ .

Figure 2.1 (A) Location map of the study area in the northeast of Mexico within Burgos Basin; blue lines: 2D seismic transect lines, white line: 2D transect TSN-15 showing Anhelido-1 well; (B) Study area within the black square (3D seismic data); (C) Close up of the entire area including the auction blocks, wells and the top of Pimienta formation in time domain (TWT).

Figure 2.2 (A) Main tectonic features of study area (modified from Hurbury et al., 2003); (B) Representative regional seismic line from 3D survey and TST-15 transect passing (see figure 2.1) across the study area (onshore) toward Gulf of Mexico (offshore) showing the main geological features from the Cenozoic sediments to the basement in vertical traveltime (TWT). From West to East, the Cretaceous thins towards the Gulf of Mexico, where it is out beneath the detached growth fault system within the eastward thickening within the thick Cenozoic depocentre at the eastern of this seismic line.

Figure 2.3 Regional tectonic evolution showing the mechanisms which interacted in the region presented in this research work; A) Triassic-Jurassic tectonic model; B) Late Jurassic

Model; C) Early Cretaceous; D) Late Cretaceous (modified from De Cserna, 1979/1989; Dickinson, 1981; Limón, 1989).

Figure 2.4 West-east cross section through the southern of Burgos Basin area, showing the geometry of the inner, Sierra Madre Oriental deformation and the presence of a second, outer zone of deformation expressed as monoclinical folding at the edge of thick continental crust. The outer zone controls many of the sequence boundaries (modified from Horbury et.al., 2003).

Figure 2.5 (A) Representative seismic line from 3D seismic survey passing across the study area showing the interpretation and the main geological features from the Cenozoic sediments to the basement in vertical traveltime (TWT). A-A' profile is displayed in an E-W direction, and shows seaward thinning of the Cretaceous megasequence, and the detachment of the growth fault system below the Eocene and Paleocene at the eastern end of the seismic line; (B) Close-up of the tilted top of the Upper Jurassic (Tamaulipas Formation) and Upper Jurassic (Pimienta Formation) which shows a negative amplitude response associated with the abrupt velocity change at this boundary.

Figure 2.6. Geological column of study area focuses on Upper Jurassic Pimienta Formation (red polygon).

Figure 2.7 Subdivision into three stratigraphic units of the Pimienta Formation in the southern portion of the Burgos Basin Burgos, Gamma Ray (GR) in red curve and Resistivity log in blue (modified from PEMEX E&P, 2012).

Figure 2.8 (A) (A-A') first part of Stratigraphic regional of Pimienta formation; (B) (B-B') second part of regional line including Serbal-1 and Anhelido-1; (C) Both lines (A-B red) and (B-B' blue) cover the entire Burgos Basin from north to south with thickness variations (modified from PEMEX, 2012).

Figure 2.9 Depositional model of Late Kimmeridgian-Tithonian showing the Jurassic paleogeography of the Pimienta Formation according with core and log data (modified from PEMEX 2012).

Figure 2.10 Burgos Basin outline and shale gas and shale oil prospective areas (modified from Horbury et. al., 2003; Perez, 1992; Salvador, 1991; PEMEX, 2013).

Figure 2.11 A) Important field in Mid Cretaceous within Eagle Ford Formation; B) Upper Jurassic field within the study area.

Figure 2.12 Elements and Events of the Tithonian-Kimmeridgian-Cretaceous Oil system in the Burgos-Tampico Misantla Oil Province (modified from PEMEX E&P, 2010).

Figure 3.1. Processing sequence in Anhelido 3D seismic data survey.

Figure 3.2 Stratigraphic interpretation in time vertical domain with exact raw amplitude extraction as quality control (TWT). A) Upper Cretaceous Mendez Formation (positive amplitude); (B) Tamaulipas Formation (positive amplitude); (C) Upper Jurassic Pimienta Formation (negative amplitude); (D) Olvido Formation (Positive amplitude) and an extra map interpretation; (E) The bottom of Olvido Formation (positive amplitude); (F) Interpretation map of Pimienta formation within Upper Jurassic Tithonian in the time domain (TWT ms).

Figure 3.3 (A) Rose diagram illustration of overall survey offset-azimuth distribution of 3D survey Anhelido 3D; (B) the acquisition offset versus azimuth distribution. Note that a uniform distribution is achieved only up to approximately 4000m offset.

Figure 3.4 Outline of the generation of OVT's, the dimensions of each of the 196 350x350 meters mosaics for this project were generated.

Figure 3.5 CRP gathers sorted in Common offset common azimuth (COCA) with the elliptical correction for anisotropy. These shot gathers show the wobbling effect when the offset increase is more noticeable and those changes in velocities may induce the anisotropy (light blue polygon).

Figure 3.6 Diagram of noise attenuation per azimuthal sector.

Figure 3.7 (A) Amplitude spectrum and calculation of seismic resolution of 46m using velocity data and seismic frequency within Pimienta Formation using time window TWT (1.2-

1.5s) and 24 Hz peak frequency; (B) Wedge model estimation using velocity data; (C) Initial Ricker wavelet of 24 Hz frequency in zero phase associated with Pimienta formation to estimate the tuning thickness of 36m.

Figure 3.8 (A) Wavelet estimation of 5 wells in the study area within Pimienta Formation with average frequency of 24 hz; (B) Amplitude spectrum of wavelets shown a stable behavior.

Figure 3.9 Synthetic seismograms showing the match between the seismic trace and the synthetic seismogram. It suggests a good agreement; Track 1 is the 3D seismic survey; Track 2 is the verticalized seismic trace; Track 3 is the synthetic trace; Track 4 is the interval velocity; (A) Well-Tie Correlation of Anhelido-1 (correlation coefficient =72%); (B) Well-Tie Correlation of Serbal-1 (correlation coefficient =73%).

Figure 3.10 Synthetic seismograms showing the match between the seismic trace and the synthetic seismogram. It suggests a good agreement; Track 1 is the 3D seismic survey; Track 2 is the verticalized seismic trace; Track 3 is the synthetic trace; Track 4 is the interval velocity; (A) Well-Tie Correlation of Espectro-1 (correlation coefficient =71%); (B) Well-Tie Correlation of Mirasol-1 (correlation coefficient =78%).

Figure 3.11 Synthetic seismograms showing the match between the seismic trace and the synthetic seismogram. It suggests a good agreement; Track 1 is the 3D seismic survey; Track 2 is the verticalized seismic trace; Track 3 is the synthetic trace; Track 4 is the interval velocity; (A) Well-Tie Correlation of Tres Palos-1 (correlation coefficient =70%); (B) Well-Tie Correlation of Cruillas-1 (correlation coefficient =65%).

Figure 3.12 (A) Representative arbitrary line from 3D Interval velocity model passing across the study area showing the horizon interpretation and the interval velocity logs in vertical travel time TWT (ms). The model was built using the time surfaces interpreted in this project focused between Upper Cretaceous and Olvido Formation. Note the very good agreement between the velocity model and the interval velocity from logs; (B) Representative 3D velocity

model showing the top of Upper Cretaceous (Mendez Formation) and the base Upper Jurassic (Olvido Formation). Note also that the Pimienta Formation has low velocity response.

Figure 3.13 (A) Representative seismic line from 3D survey passing across the study area showing the horizon interpretation and the main geological features and logs information Gamma Ray (green) and Resistivity in red color from the Cenozoic sediments to the basement in vertical travel time TWT (ms). The Cretaceous thins at the eastern of the seismic line; (B) Representative seismic line from 3D survey passing across the study area flattened at the top of Pimienta Formation; (C) The arbitrary line A-A' is shown on the map of Pimienta Formation (top) in TWT (ms).

Figure 3.14 (A) Well log data set in Anhelido-1 (Vertical well); (B) Logging in horizontal section of Anhelido-1H. C) Well log data set in Serbal-1 (vertical well); (C) Logs in horizontal section of Serbal-1H, Pimienta Formation is highlighted in yellow in the vertical wellbores.

Figure 3.15 (A) Linear combination of attribute samples at the same depth and its weight values; (B) Attributes used for regression to estimate the S-Wave log and its correlation values.

Figure 3.16 (A) The training error is the error using six wells in the prediction, and the cross-validation error is the error in which the well to be predicted is left out of the training; (B) The final correlation in of predicted S wave in the y-axis and the Real S wave in the x-axis show an excellent result of a correlation of $R^2 = 0.98$.

Figure 3.17 Validation of multiple attribute regression in six wells, Average error or Prediction Error shown at the top of the display is the RMS error or difference between the predicted (red) and actual logs (black) within the analysis window flattened at the top of the Pimienta Formation.

Figure 3.18 (A) LOM value based on Passey et al. (1990); (B) Type of Kerogen for Anhelido-1 & Serbal-1.

Figure 3.19 Estimation of TOC curves using Passey's formulation constrained with Ro and LOM values in the wells of the study area. The pyrolysis TOC samples are superposed in green with very good agreement.

Figure 3.20 LomLab R1 Graphical User Interface to compute TOC and Brittleness index.

Figure 3.21 Rock Physics cross-plots coloured with Brittleness values in Anhelido-1 within Pimienta Formation (reservoir zone); (A) Cross-plot Poisson Ratio vs Young's modulus; (B) Cross-plot Brittleness vs Young's modulus; (C) Cross-plot Poisson Ratio vs Brittleness; (D) 3D Cross-Plot (Poisson's Ratio, Young's Modulus and Brittleness).

Figure 3.22 Conventional brittleness Index estimation in five wells by using Rickman's equation and brittleness using the Wang approach from XRD data.

Figure 3.23 (A) Representative arbitrary line of the low frequency Model (Acoustic impedance) across the wells of the project area; (B) first approach of acoustic impedance inversion results with a range of values of 4000 to 20000 (m/s*gr/cc). Zoom panels are shown for every well (from 1-6) to examine the match between the inverted traces, the log data, and the stratigraphic tops. Note the good agreement within the reservoir zone (Pimienta Formation); Horizon shown in light blue is the top of Pimienta Formation and the horizon in darker blue is the top of Olvido formation or the base reservoir of Pimienta Formation.

Figure 3.24 (A) Arbitrary acoustic impedance line (A-A') of Vertical and horizontal wellbore Anhelido-1 with displayed gamma ray and resistivity logs; (B) Arbitrary acoustic impedance line (B-B') of Vertical and horizontal wellbore Serbal-1 with displayed gamma ray and resistivity logs. The horizontal well trajectory (red line in the map location) is landing within Pimienta Formation with 17 hydraulic fracturing stages in both wells.

Figure 4.1. Orthorhombic symmetry is commonly formed by embedding a set of parallel vertical fractures in VTI background.

Figure 4.2. (A) Evidence of vertical fractures at 2111-2112m depth; (B) Penny-shaped cracks that are kerogen filled and associated with disseminated pyrite.

Figure 4.3. Evidence of vertical fractures cemented by calcite (veins) at 2908-2910m depth for Serbal-1

Figure 4.4. Hudson's Model – Penny-Shaped cracked model (modified from Hudson, 1981).

Figure 4.5. Representation of Schoenberg's Linear-Slip model for fractured rock with infinitely long planes of weakness (modified from Schoenberg , 1983, 1988, 1989).

Figure 4.6. Comparison of exact and approximate reflectivity calculated using the Rüger AVO equation shown in eq 5.1. In all images the solid line represents exact reflectivity, and the dashed line represents approximated reflectivity. The leftmost image depicts the isotropic case. The middle image depicts the HTI case associated with fluid filled fractures. The rightmost image depicts the HTI case associated with dry fractures. The X axis represents incident angle, and the Y axis represents reflectivity.

Figure 4.7. Thomsen's model fractured HTI anisotropy.

Figure 4.8. Backus averaging upscaling method; (A) represents model composed with three different stiffness tensors; (B) is the upscaled rock assuming only one effective stiffness tensor in VTI media.

Figure 4.9. Third-order sequence stratigraphy model between vertical wells Anhelido-1 and Serbal-1; (A) Landing zone of the horizontal wellbore Anhelido-1H (magenta arrow) depth (2113m); (B) Landing zone of the horizontal wellbore Serbal-1H (light blue arrow) depth (2908m); According with Gamma ray signature Anhelido-1H and Sernal-1H landed in the spike of the mfs zone in the sequence model (modified from Slat and Rodriguez, 2010).

Figure 4.10. (A) Bulk modulus varying with porosity ϕ at Anhelido-1 showing the influence of pore aspect ratio in Pimienta Formation with logging data (Porosity ϕ) overlapped

the average value of aspect ratio between (0.1-0.2) approximately according with this graph; (B) Aspect ratio near to 1.0 increases Bulk modulus for a given porosity (Russell and Smith, 2007); (C) SEM photograph of a sample with ellipsoidal cracks of the mid unit of Pimienta Formation in analogue well; (D) Graphical definition of pore aspect ratio.

Figure 4.11. (A) Bulk modulus varying with porosity ϕ at Serbal-1 showing the influence of pore aspect ratio in the Pimienta Formation with logging data (Porosity ϕ) overlapping with the average value of aspect ratio between (0.04-0.16) approximately according with this graph; (B) Aspect ratio near to 1.0 increases P-wave velocity for a given porosity (Russell and Smith, 2007); (C) SEM photograph of a sample at Serbal-1 with ellipsoidal crack of the mid unit of Pimienta Formation; (D) Graphical definition of pore aspect ratio.

Figure 4.12. (A) Backus averaging upscaling V_p , V_s and *density* at Anhelido-1 within the Pimienta Formation. B) Thomsen's parameters from Backus average at Anhelido-1 within the Pimienta; (C) Backus averaging upscaling V_p , V_s and *density* at Serbal-1 within the Pimienta Formation. D) Thomsen's parameters from Backus average at Serbal-1 within the Pimienta Formation.

Figure 4.13. Graphical user Interfaces developed to compute the Thomsen's parameters using fractured models; (A) Hudson model; (B) Schoenberg Linear-slip model.

Figure 4.14. Fracture models from effective medium comparison and their anisotropic parameters differences at 28° angle incidence in the azimuthal synthetic gather at Anhelido-1. The green horizon line reference represents the top of Pimienta Formation for every model; (A) Hudson model azimuthal ring synthetic gather; (B) Linear-Slip model azimuthal ring synthetic gather- note an amplitude perturbation between (150° and 200°); (C) Rüger-Thomsen model - barely noticeable changes in amplitude distortions.

Figure 4.15. Fracture models from effective medium comparison and their anisotropic parameters differences at 28° angle incidence in the azimuthal synthetic gather at Serbal-1-1. The green horizon line reference represents the top of Pimienta Formation for every model; (A)

Hudson model azimuthal shows changes in amplitude at ring synthetic gather between (150° and 200°); (B) Linear-Slip model azimuthal ring synthetic gather: note an amplitude perturbation between (150° and 200°); (C) Rüger-Thomsen model barely noticeable changes in amplitude distortions.

Figure 4.16. Synthetic azimuthal seismic gather modelling using Linear-slip fracture model at Serbal-1 within Pimienta formation; (A) Angle incidence “rings” (0°, 28°, 43°, and 55°) and azimuth full range (0° - 360°); (B) Reflectivity of angle incidence and azimuthal full range; (C) Azimuthal amplitude seismic gather of angle incidence and full azimuth.

Figure 4.17. (A) Azimuthal synthetic gather for Hudson model and AVA curves at 28° angle incidence and azimuth 125° perpendicular to fractures based on project area information and polar view of wave field reflectivity ($R_{psv}, R_{psh}, R_{ps-iso},$); (B) Azimuthal synthetic gather for Linear-slip model and AVA curves at 28° angle incidence and azimuth 125° perpendicular to fractures based on project area information and polar view of wave field reflectivity ($R_{psv}, R_{ps}, R_{ps-is},$) in Anhelido-1 within Pimienta Formation.

Figure 4.18. (A) Azimuthal synthetic gather for Hudson model and AVA curves at 28° angle incidence and azimuth 128° perpendicular to fractures based on project area information and polar view of wave field reflectivity ($R_{psv}, R_{psh}, R_{ps-l},$); (B) Azimuthal synthetic gather for Linear-slip model and AVA curves at 28° angle incidence and azimuth 128° perpendicular to fractures based on project area information and polar view of wave field reflectivity ($R_{psv}, R_{ps}, R_{ps-ls},$) in Serbal-1 within Pimienta Formation.

Figure 4.19. Baniz user interface to perform the modelling of anisotropic gradient related to fracture density.

Figure 4.20. (A) Fracture density estimation using fracture models in terms of weak anisotropy from Thomsen’s formulation as a function of crack density and weakness at Anhelido-1 within the Pimienta Formation; (B) Fracture density estimation using fracture models in terms

of weak anisotropy from Thomsen's formulation as a function of crack density and weakness at Serbal-1 within the Pimienta Formation.

Figure 4.21. AVA models from an HTI shale within Upper Jurassic underlying a carbonate rock from lower Tamaulipas formation using Blangy solution (Blangy, 1994) for the anisotropic case using fracture models (Hudson 1981; Schoenberg 1980), the Backus average (Backus, 1962), Ryan-Grigor (Ryan-Grigor, 1994) and Rüger approximations (Rüger, 1996, Rüger, 1997, Rüger, 1998). The dashed line represents the isotropic case.

Figure 4.22 (A) World stress map Rel. 2016 of present stress field within the study area; (B) Close-up of study area with the stress orientation of the S_{Hmax} (Heidbach et al., 2016) based on borehole breakout information.

Figure 4.23. (A) Blocky models using the fracture models (Hudson and Linear-slip) parallel to stress S_{Hmax} and fractures, AVO curves of wave field R_{psv} , R_{psh} , and R_{ps-ls} and its polar view, green line represent stress-fracture direction in azimuth according with the stress map (52° and 66°); (B) Blocky models using the fracture models (Hudson and Linear-slip) perpendicular to stress S_{Hmax} and fractures, AVO curves of wave field R_{psv} , R_{psh} , and R_{ps-ls} and its polar view, green line represent S_{Hmin} direction in azimuth (114° and 125°).

Figure 4.24. (A) Anisotropic wave propagation for given anisotropic parameters in VTI mode within Pimienta Formation at Anhelido-1 using Hudson's Model; (B) Anisotropic wave propagation for given anisotropic parameters in HTI mode within Pimienta Formation at Anhelido-1 using Hudson's Model.

Figure 4.25. (A) Anisotropic wave propagation for given anisotropic parameters in VTI mode within Pimienta Formation at Anhelido-1 using Linear-slip Model; (B) Anisotropic wave propagation for given anisotropic parameters in HTI mode within Pimienta Formation at Anhelido-1 using Linear-slip model.

Figure 4.26. (A) Anisotropic wave propagation for given anisotropic parameters in VTI mode within Pimienta Formation at Serbal-1 using Hudson's Model; (B) Anisotropic wave

propagation for given anisotropic parameters in HTI mode within Pimienta Formation at Serbal-1 using Hudson's Model.

Figure 4.27. (A) Anisotropic wave propagation for given anisotropic parameters in VTI mode within Pimienta Formation at Serbal-1 using Linear-slip Model; (B) Anisotropic wave propagation for given anisotropic parameters in HTI mode within Pimienta Formation at Serbal-1 using Linear-slip model.

Figure 4.28. (A) Guo and Liu (2018), Seismic rock physics characterization of anisotropic shale a Longmaxi Shale case study. A model designed for seismic inversion for the Longmaxi Shale in VTI. The lower right panel illustrates AVO amplitudes picked from real data; (B) Anisotropic Shale characterization of the Pimienta Formation, with an azimuthal synthetic model through linear Slip modelling and AVA amplitude picked from the synthetic at 28 ° angle of incidence using different approaches of fracture models in effective medium for HTI at Serbal-1.

Figure 4.29. Comparison between ultrasonic velocity measurements at different depths within Pimienta Formation on simulated fractured medium (Hsu and Schoenberg, 1993) – red dots (Parallel), and blue dots (orthogonal) using the theoretical predictions of Hudson's models for volumetric distribution of cracks (Hudson, 1981) and planar distribution of cracks (Hudson, 1997). Aspect ratio of the cracks is considered 0.1 according to table 4.9.

Figure 4.30. Anisotropic parameters (A) $\varepsilon^{(V)}$, (B) $\delta^{(V)}$ and (C) $\gamma^{(V)}$ for a single set of vertical penny-shaped dry cracks (Grechka and Kachanov, 2006). Note: The background P-wave velocity is 3.0 km/s and S-wave velocity is 1.0 km/s; and density is 2.2g/cm³. Symbols indicate different theoretical predictions: red ∇ -the first-order Hudson's method, red Δ -the second-order Hudson's method, Schoenberg's method, and blue O -the non-interaction approximation (Grechka and Kachanov, 2006) that considers the crack aspect equals 0.05 for all fractures. Bars correspond to the 95% confidence intervals (the mean values of standard deviations) of the numerically computed anisotropic parameters obtained for 100 random realizations of the fracture locations.

Figure 4.31. Anisotropic parameters (A) $\varepsilon^{(V)}$, (B) $\delta^{(V)}$ and (C) $\gamma^{(V)}$ from four samples at different confining pressures within Pimineta formation at Anehido-1.

Figure 4.32. Azimuthal ring gather synthetic Ryan-Grigor anisotropic parameters from well log data at Anhelido-1 within Pimienta Formation.

Figure 5.1. HTI model used in Ruger formulation (1997) P-wave reflection equation showing anisotropic conversion to shear-waves for principal and non-principal planes of symmetry.

Figure 5.2. Azimuthal reflectivity for a constant angle of incidence

Figure 5.3. (A) Seismic gather sorted by angles and azimuths it shows apparent fast (V_{fast}) and slow (V_{slow}) azimuth;(B) The sinusoid (wobbling effect) describes a representative ellipse with the fast direction represented by long axis (modified from Treadgold et al., 2008).

Figure 5.4. Map indicating the different areas where AVAZ attributes were calculated within the study area and Pimienta formation; (A) Entire 3D seismic survey of study area; (B) Selected area around Serbal-1 for AVAZ calculation;(C) Selected area around Anhelido-1 for AVAZ calculation.

Figure 5.5. 3D survey in the study area yellow square represent the points where the azimuthal gather was displayed in each well (red lines represent the number of traces selected).

Figure 5.6. (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Mirasol-1 (trace 11503); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within Pimienta Formation; (C)Snail gather representation (Source: CGG University training material).

Figure 5.7. (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Espectro-1 (trace 11269); (B) Close-up of mid to far angles of

incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within the Pimienta Formation; (C) Snail gather representation (Source: CGG University training material).

Figure 5.8. (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Serbal-1 (trace 11355); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within the Pimienta Formation; (C) Snail gather representation (modified from CGG University training material).

Figure 5.9. (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Anhelido-1 (trace 11451); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within the Pimienta Formation; (C) Snail gather representation (Source: CGG University training material).

Figure 5.10. (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Tres Palos-1 (trace 12101); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within the Pimienta Formation; (C) Snail gather representation (Source: CGG University training material).

Figure 5.11. Microseismic downhole geophone array receiving seismic events (modified from Rodvelt, 2014).

Figure 5.12. Location at Well-1, Well-1H, and monitor well for microseismic survey

Figure 5.13. Configuration of monitor Well-1 and Well-1H for microseismic technology. Note: there are 11 hydraulic stages in horizontal section within the Pimienta formation with $\sim 91^\circ$ Dip and azimuth $\sim 85^\circ$, a total length of 1060m and 11 geophones to monitor well treatment. The distance from the horizontal side to the monitor well is 90m apart; (A) Lateral view of horizontal side of Well-1H; (B) Top view of horizontal side of Well-1H.

Figure 5.14. Scale of seismic events and bandwidths of various seismic systems (modified from Baig and Urbancic, 2010).

Figure 5.15. Microseismic events at Well-1H within the Pimienta Formation, the events are coloured by stage and sized by energy and related to the hydraulic stage; (A) Top view of horizontal side of Well-1H; (B) Lateral view of horizontal side of Well-1H; (C) Front view of horizontal side of Well-1H.

Figure 5.16. Workflow to obtain Ant-Tracker attribute for fault detection in the study area around Well-1 and Well-1H.

Figure 5.17. Workflow for the estimation of the Ant-tracker attribute at Well-1 and Well-1H location (inline-1362, xline-5209); (A) Original seismic data Pre-Stack Time Migration (PSTM); (B) Structural smoothing data conditioning; (C) Edge detection attribute known as variance or coherence; (D) Edge enhancement attribute Ant-tracker.

Figure 5.18. Diagram of organic shale rock.

Figure 5.19. Petrophysical evaluation within Pimienta Formation; A) Gamma ray log (black) with no radioactive components Uranium (U), Thorium (Th), and Potassium (K), the Gamma ray log (green) with radioactive components (U), (Th), and (K), the core Gamma ray (blue) with its radioactive components (U), (Th), and (K); B) Effective porosity log (red) and core porosity (black dots); C) TOC log (black) and TOC samples from RockEval (red dots); D) Mineral proportions including kerogen fraction (black).

Figure 5.20. Relationship between TOC, P-wave velocity, the volume fraction of quartz and clay in 3D scatter data within Pimienta Formation; A) Velocity decreases with high clay fraction and high TOC; B) Velocity increases with high quartz fraction and low TOC content.

Figure 5.21. Effect of volume fraction of kerogen and TOC on A) Bulk Modulus; B) Shear Modulus of incompressibility; C) Poisson's ratio of Organic-Rich shale within Pimienta Formation encountered at 2074-2145m depth in Anhelido-1.

Figure 5.22. Relationship between elastic stiffness coefficients (C_{11} and C_{33}) and kerogen fraction; A) Impact on kerogen fraction as a function of (C_{11} and C_{33}) within Pimienta Formation

B) Impact on kerogen fraction as a function of (C_{11} and C_{33}) on Bakken shale suggesting the same behaviour.

Figure 5.23. Relationship between elastic stiffness coefficients (C_{55} and C_{66}) and kerogen fraction; A) Impact on kerogen fraction as a function of (C_{55} and C_{66}) within Pimienta Formation B) Impact on kerogen fraction as a function of (C_{55} and C_{66}) on Bakken shale suggesting the same behaviour.

Figure 5.24. A) Elastic stiffness coefficients C_{11} (stars) and C_{33} (blue light points) computed from bedding-parallel and bedding-normal ultrasonic P-velocity measurements reported by Vernik and Liu (1997) in Bakken shale at high confining pressure (70 MPa) versus kerogen content and stiffness coefficients within Pimienta Formation using ultrasonic measurements from log data P-velocity C_{11} (red points) and C_{33} (blue points); B) Elastic stiffness coefficients C_{66} (stars) and C_{55} (blue light points) computed from bedding-parallel and bedding-normal ultrasonic P-velocity measurements reported by Vernik and Liu (1997) in Bakken shale at high confining pressure (70 MPa) versus kerogen content and stiffness coefficients within Pimienta Formation using ultrasonic measurements from log data P-velocity C_{55} (red points) and C_{66} (blue points).

Figure 5.25. Vertical P and S-wave velocity logs (black) within Pimienta Formation at Anhelido-1 with different model approach.

Figure 5.26. The dry-rock bulk and shear moduli for aspect ratio pores ($\alpha= 0.1$) (Li and Zhang, 2010) and aspect ratio ($\alpha= 0.05$) within the Pimienta Formation (reservoir zone); Agreement between the complete DEM calculation and the analytical formula is very good.

Figure 5.27. Bulk moduli of porous glass foam computed from compressibilities measured by Walsh et al. (1965). Measured values (black rectangles) are compared to theoretical predictions of DEM theory (spherical pores). The dashed line is computed from the approximate formula. The dotted (black) curve is the theoretical prediction of SC theory for spherical pores,

and coloured curves (are theoretical predictions of DEM theory using different aspect ratios and superposed samples of the Pimienta Formation.

Figure 5.28. A) Minerals volume fraction; B) Vertical P -wave velocity (black) from log data measured; and V_p predicted from modelling (red) DEM analysis and Gassman's theory; B) Vertical S -wave velocity (black) from log data measured; and V_s predicted from modelling (red); D) Correlation $R^2=0.9987$ between V_p logged and V_p predicted from modelling; E) Correlation $R^2=0.9976$ between V_s logged and V_s predicted from modelling.

Figure 5.29. (A) Representative of mineral A Voigt model; (B) Representative of mineral B Reuss; (C) Crossplot of empirical lithological models (Porosity (%) vs. P-Velocity (km/s)) (modified from Mavko et.al., 2009 including the Pimienta Formation).

Figure 5.30. Crossplot Porosity vs P-Velocity with Gamma Ray color-coded; (A) Voigt and Reuss bounds at Anhelido-1 within the Pimienta Formation (reservoir zone); (B) Voigt and Reuss bounds at Anhelido-1 within the Pimienta Formation (reservoir zone), in A) Anhelido-1 Porosity vs. V_p log data and samples and B) Serbal-1 using Python code.

Figure 5.31..(A) Scattering plot of Density vs. P-Velocity within the Pimienta Formation according to XRD and well logs data using RokDoc software; (B) The yellow polygon in crossplot highlight the Gamma Ray log in the Pimienta formation at Anhelido-1 within the Pimienta Formation.

Figure 5.32. (A) Scattering plot of Density vs. P-Velocity within the Pimienta Formation according to XRD and well logs data using RokDoc software; (B) The yellow polygon in crossplot highlight the Gamma Ray log at Serbal-1 within the Pimienta formation.

Figure 5.33. A normal bedding P-Impedance vs S-Impedance scattering with log data of different shale formation of the USA, including the Pimienta Formation (red). Adapted from Khadeeva and Vernik (2014). The Pimienta Formation is stiffer than its counterparts due to high P/S-impedance.

Figure 5.34. Illustration of P-wave, Swave propagation, and polarization fractions concerning the bedding plane of organic shale. The value in parenthesis indicates the angle for the bedding normal symmetry axis (modified from Vernik and Nur, 1992).

Figure 5.35. (A) Elastic constants; (B) Young's Modulus (well-log), Vertical (0°) & Horizontal (90°) Young's Modulus; (C) Poisson's Ratio (well-log), Vertical (0°) & Horizontal (90°) Poisson's Ratio; (D) Vertical (0°) or BI (0°) & Horizontal (90°) or BI (90°) Brittleness index at Anhelido-1. The Pimienta Formation is highlighted in yellow.

Figure 5.36. (A) Elastic constants; (B) Young's Modulus (well-log), Vertical (0°) & Horizontal (90°) Young's Modulus; (C) Poisson's Ratio (well-log), Vertical (0°) & Horizontal (90°) Poisson's Ratio; (D) Vertical (0°) or BI (0°) & Horizontal (90°) or BI (90°) Brittleness index at Serbal-1, the Pimienta Formation is highlighted in yellow.

Figure 5.37. (A) Different Brittleness index estimation by different research approaches, including the anisotropic Brittleness proposed in this thesis work (BI (0°) black and BI (90°) Orange) at Anhelido-1; (B) Different Brittleness index estimation by different research approaches, including the anisotropic Brittleness proposed in this thesis work (BI (0°) black and BI (90°) Orange) at Serbal-1; Pimienta Formation is highlighted in yellow.

Figure 5.38. (A) Anisotropic rock physics scatter plot of vertical Young's Modulus-Poisson's Ratio, color-coded with vertical (0°) brittleness; (B) Anisotropic rock physics scatter plot of vertical Young's Modulus-Poisson's Ratio, color-coded with horizontal (90°) brittleness; (C) Vertical BI (0°) and horizontal BI (90°) brittleness logs proposed in this work fit much better with the brittleness from mineral proportions XRD (Wang, 2009) in comparison with another researcher's brittleness. The bound in the scatter plot changes dramatically when it goes from 0° to 90° , which may reveal anisotropy induced by mechanical properties in the rock itself.

Figure 5.39. Graphical User Interface developed in MATLAB; (A) From left to right the displayed logs are (1) Young's Modulus, (2) Poisson's Ratio, (3) Anisotropic Young's Modulus, (4) Anisotropic Poisson's Ratio, (5) Anisotropic Brittleness, (6) Elastic constants; (B) Scatter plot

(Anisotropic Brittleness vs Anisotropic Young's Modulus); (C) Anisotropic Brittleness Index of different researchers including BI (0°) and BI (90°) proposed in this thesis.

Figure 5.40. V_{SH} and V_{sv} measured and estimated using effective field method (EFM) within Tamaulipas and Pimienta Formation.

Figure 5.41. A) Crack density log estimation; B) V_{fast} and V_{slow} within Tamaulipas and Pimienta Formation

Figure 5.42 Angle between the borehole axis and the normal to the crack system.

Figure 5.43. Scatter plot V_{sv} and V_{SH} using effective field method EFM and the correlation between measured and calculated velocities.

Figure 5.44. Lateral view of Horizontal wellbore Anhelido-1H and the extraction window of B_{ani} .

Figure 5.45. Terms obtained in Rüger equation where B_{ani} is related the fracture density and isotropy plane direction ϕ the azimuth volume; when these volumes are combined it can estimate the glyphs (vector distribution of possible fracture orientation) which is related to the direction of fast velocity or stress.

Figure 5.46 Relationship between Crack density and B_{ani} .

Figure 5.47. Synthetic azimuthal gather created using the velocities and densities from well logs.

Figure 5.48. Four snail gathers along horizontal side of the wellbore Anhelido-1H to investigate the differences in residual travel time of V_{fast} , V_{slow} and azimuth.

Figure 5.49. CDP angle gather subdivided in near, Mid, and far angle incidence; A) Angle gather sector 1(0-90°); B) Angle gather sector 2(90-180°); C) Angle gather sector 3(180-270°); D) Angle gather sector 4(270-360°).

Figure 5.50. (A) Fracture density B_{ani} attribute extracted in Anelido-1 within Pimienta formation with overlapping the fracture vectors as a result of the combination of the azimuth A_z and fracture density B_{ani} ; (B) Fracture density B_{ani} attribute extracted in Serbal-1 within the Pimienta Formation with overlapping the fracture vectors as a result of the combination of the azimuth A_z and fracture density B_{ani} ; Gamma Ray (GR) logs were displayed in horizontal well segments.

Figure 5.51. Arbitrary line of anisotropic gradient B_{ani} along with the horizontal survey well path in Anhelido-1H, colour code represents the fracture density. The well-path navigation is within the the Pimienta Formation. High values are evident from Stage 9 to stage13 and Stage 15 to stage 17.

Figure 5.52. Arbitrary line of anisotropic gradient B_{ani} along with the horizontal survey well path in Serbal-1H, colour code represents the fracture density. The well-path navigation is within the Pimienta Formation.

Figure 5.53 (A) Attribute extraction from anisotropic gradient B_{ani} using 12ms centred window using the Pimienta Formation surface within the target zone along the horizontal wellbore side Anhelido-1H; (1) Yellow polygon enclose zone around Anhelido-1 and its correspond rose diagram of fast velocity related to fracture orientation; (2) It is noticed how the attribute is high quantitatively in fracture density from the stage 10 to stage17 in colour green polygon and its correspond rose diagram of fast velocity related to fracture orientation; (3) From stage 1 to stage 3 in magenta polygon low fracture density is shown. The rose diagram of fracture count (red) in the well shows a dominant direction striking N30 degrees.

Figure 5.54 (A) Attribute extraction from anisotropic gradient B_{ani} using 12ms centred window using Pimienta formation surface within the target zone along the horizontal wellbore side Anhelido-1H; (1) Yellow polygon enclose zone around Serbal-1 and stage 14 to stage 17 and its correspond rose diagram of fast velocity related to fracture orientation; (2) It is noticed how the attribute is high quantitatively in fracture density from the stage 6 to stage13 in colour green

polygon and its correspond rose diagram of fast velocity related to fracture orientation; (3) From stage 1 and stage 2 in magenta polygon high fracture density is shown. The rose diagram of fracture count (red) in the well corresponding to positions in the horizontal segment are shown labelled 1-3.

Figure 5.55. (A) Synthetic azimuthal gather at Anhelido-1 depth 2113m generated using the Hudson model based on fracture models listed in table 5.7 it is observed amplitude distortion in far angle incidence (dashed black polygon); (B) Azimuthal AVO curves are created with this model color-coded with incidence angle; (C) Amplitude map variations with azimuth to emphasize the azimuthal changes within the common angles common azimuth gather (COCA).

Figure 5.56. (A) Synthetic azimuthal gather at Anhelido-1 depth 2113m generated using the Linear-slip model based on fracture models listed in table 5.7. Amplitude distortion is observed in far angle incidence (dashed black polygon); (B) Azimuthal AVO curves are created with this model color-coded with incidence angle; (C) Amplitude map variations with azimuth to emphasize the azimuthal changes within the common angles common azimuth (COCA).

Figure 5.57 (A) Ant-tracker depth slice at top of Pimienta formation (25m above); (B) Image of fracture segments processed and handled in FracPaQ; (C) Rose diagram estimated from ant-tracker attribute and processed in FracPaQ with mean vector fracture orientation (white arrow) (Healy, 2012).

Figure 5.58 (A) FMI log (Fracture Density) at Well-1; (B) Ant-tracker slice at 2500 m within the Taraises Formation;(C) Ant-tracker slice at 2525 m within the Taraises Formation; (D) Ant-tracker slice at 2725 m within the Pimienta Formation.

Figure 5.59. (A) Combination of microseismic data at horizontal analogue Well-1H overlain with the AVAz attribute B_{ani} , and ant-tracker attribute. (B) The fault strike data from the ant-tracker attribute, microseismic events, and fracture swarm vectors from AVAz suggest that orientation of faults are mainly NE striking, as displayed in the rose plot derived using FracPaQ open-source MATLAB code (Healy, 2012).

Figure 5.60. FMI log fracture density comparison with extracted trace of B_{ani} at Well-1 within the Pimienta Formation and the Taraises Formation; (A) Fracture density log/Extracted Trace B_{ani} comparison depth (2500m and 2525m Taraises Formation); (B) Fracture density log/Extracted Trace B_{ani} comparison depth (2625m Pimienta Formation); (C) Fracture density log/Extracted Trace B_{ani} comparison depth (2725m Pimienta Formation); (D) Caliper used for measuring borehole ovality within the Pimienta Formation; (E) Natural fractures occur preferentially oriented N-S, with average angles of 67.60 degrees classified as subvertical.

Figure 5.61. Fluid substitution modelling in fracture model as a synthetic azimuthal gather using the Brown-Korringa (Brown and Korringa, 1975) formulation at Anhelido-1 at a depth of 2113m. The green line in the synthetic azimuthal gather indicates the top of the Pimienta formation; (A) Azimuthal gather in the dry case; (B) Azimuthal gather in the oil substitution case; (C) Azimuthal gather in the (wet) brine case; (D) Reflectivity curves as a function of azimuth showing results from all the cases combined.

Figure 5.62. AVA curves modelling for Oil and Brine case in seven different azimuths. The colour dashed lines in the azimuthal synthetic gather indicates the azimuth taken for each AVA modelling at a 28° angle incidence.

Figure 5.63 AVA Modelling at azimuth 50° ;(A) Brine case; (B)Oil case; (C)Gas case using fluid substitution by Brown and Korringa, 1975; (D) Real angle seismic trace (magenta) displayed over the model values.

Figure 5.64 Graphical user interface FluidAnisoMod using MATLAB to perform fluid replacement modelling in shale rocks.

Figures 5.65 (A) Microseismic events along horizontal side of Well-1H; (B) Microseismic events along the landing zone of Well-1H; (C) Top view of the microseismic activity, the color-code represents every hydraulic stage stimulation and the size of the microseismic event is the magnitude.

Figures 5.66 Fractures with a preferential orientation produce anisotropy in the velocity of the S waves.

Figure 5.67. Scheme of brittleness calculation ($Brit_V$ (0°)) is in the symmetry axis equal to 0° and ($Brit_H$ (90°)) is in the symmetry axis equal to 90° .

Figure 6.1 (A) Entire study area; (B) Selected area 9.2 Km² around Ahelido-1 and Anhelido-1H for the azimuthal seismic inversion.

Figure 6.2 Phase wavelet examples and amplitude spectra.

Figure.6.3 The Roy White methodology.

Figure 6.4. Wavelets time response used in the project using Roy White approach near zero wavelet for the inversion process (6 wells in total in the study area); then in Anhelido-1 more wavelets estimation will be calculated in for azimuthal sectors in this chapter (Figure 6.7).

Figure 6.5. Goodness of Fit and Wavelet Estimation Error vs. L/T ratio. As the (L/T) ratio goes up, or the wavelet length to window length goes up, the goodness of fit, or PEP always increases.

Figure 6.6. Arbitrary line along trajectory of well Anhelido-1H and vertical well Anhelido-1 displaying Gamma-ray and Resistivity logs with a total length in horizontal side of 1435m; A total of 17 treatment stages set in the horizontal section

Figure 6.7. (A) Azimuthal sector 1 (0° - 90°) and four angle stacked volumes (Near, Mid, Far, and Ufar); (B) Azimuthal sector 2 (89° - 180°) and four angle stacked volumes (Near, Mid, Far, and Ufar); (C) Azimuthal sector 3 (179° - 270°) and four angle stacked volumes (Near, Mid, Far, and Ufar); (D) Azimuthal sector 3 (269° - 360°); and four angle stacked volumes (Near, Mid, Far, and Ufar); (E) Azimuth angle distribution of the seismic gathers; These volumes correspond to a small area around the horizontal wellbore Anhelido-1H including Anhelido-1.

Figure 6.8. Wavelets (Near, Mid, Far, and Ultrafar) for every sector within reservoir zone (Pimienta Formation); A) Wavelets at Sector1 (0°-90°); B) Wavelets at Sector2 (90°-180°); C) Wavelets at Sector3 (180°-270°); D) Wavelets at Sector4 (270°-360°).

Figure 6.9. Static Young's Modulus from uniaxial stress-strain profile REF PEMEX E&P (modified from Keaton, 2018. The static Young's Modulus is measured from the slope of the loading line in the stress-strain region II highlighted in light yellow.

Figure 6.10. Mechanism of the overpressure for the Pore pressure estimation (after Hoesni 2004).

Figure 6.11. Static UCS from triaxial analysis and its correction using NPHI log at Anhleido-1 within Pimienta Formation.

Figure 6.12. Biot's coefficient estimation within Pimienta Formation; (A) Effective porosity from log and CORE; (B) Static and dynamic Bulk Modulus; (C) Permeability log and mercury injection samples; (D) Biot's coefficient with 0.4 average (black dashed line).

Figure 6.13. Workflow to estimate DHSR

Figure 6.14. (A) Tensile cracks will form in omnidirectional way; (B) Fractures parallel to the maximum horizontal stress will form (Gillot, 2014; Baker Hughes & CGG alliance).

Figure 6.15. Inversion results in azimuthal sectors (e.g., P-Impedance, S-Impedance, Density and V_p/V_s ratio) at well location Anhelido-1. In each sector it is shown the low-frequency curve (black), log response (blue) and the inverted trace (red), the correlation for all azimuth sectors are above >90% and four angle dependent wavelets are shown in blue colour from near to far incidence angle; (A) Inverted result at Sector 1(0°-90°); (B) Inverted result at Sector 2 (90°-180°); (C) Inverted result at Sector 3 (180°-270°) and finally; (D) Inverted result at Sector 4 (270°-360°)

Figure 6.16. Regression lines and its correlation in linear behaviour between P-impedance inverted vs. P-impedance log and $\frac{V_p}{V_s}$ log vs. $\frac{V_p}{V_s}$ inverted data per azimuth sector; (A) Crossplot in

Sector 1 (0° - 90°) ($R^2=94$); (B) Crossplot in Sector 2 (90° - 180°) ($R^2=90$); (C) Crossplot in Sector 3 (180° - 270°) ($R^2=97$); (D) Crossplot in Sector 4 (270° - 360°) ($R^2=93$); The impedance volumes P-S for each azimuthal sector were obtained with an excellent correlation these volumes will be of great importance to be used in the TOC upscaled equation since the aim is derive impedance attribute maps (Z_p , Z_s), per azimuth within the Pimienta Formation.

Figure 6.17. PI-SI scattering template, showing log derived impedances and TOC values in Anhelido-1. Superposed are: (1) zero-TOC background-trend red line regression and 5.8% TOC (blue line).

Figure 6.18. TOC regional Map from study area, source (PEMEX E&P, 2015) The map was obtained from the results of pyrolysis performed on the well samples of the study area. For Regional area, it was observed that it is found with average values in the range of $>3\%$ within the study area.

Figure 6.19. The Inverted P-Impedance (Z_p) & S-Impedance (Z_s) results for each sector where ϕ is the azimuth and the Impedances logs P and S overlapped in the seismic image with excellent agreement between P-S Impedance logs and inverted traces.

Figure 6.20. Azimuthal upscaled TOC in sub seismic volumes per sector around Anhelido-1 and Anhelido-1H; (A) TOC at Sector 1 (0° - 90°); (B) TOC at Sector 2 (90° - 180°); (C) TOC at Sector 3 (180° - 270°); (D) TOC at Sector 4 (270° - 360°).

Figure 6.21. (A) histogram of TOC content within Pimienta Formation from well log information and RockEval; (B) Range of TOC found within the inverted TOC data in four azimuth sectors, the range between 5% and 6.5% in average (Figure 6.21).

Figure 6.22 (A) TOC surface attribute histograms at Sector 1 (0° - 90°); (B) TOC surface attribute histogram at Sector 2 (90° - 180°); (C) TOC surface attribute histogram at Sector 3 (180° - 270°); (D) TOC surface attribute histogram at Sector 4 (270° - 360°).

Figure 6.23. Triaxial test samples of stress-strain curves to estimate the static Young's Modulus as a cut-off of elastic limit on seismic inversion to find the best mechanical properties within Pimienta formation, considering this, I have defined the values of $E < 19 \text{ GPa}$ as a ductile, rock and $E > 19.5 \text{ GPa}$ as a brittle rock.

Figure 6.24. Mohr's circles through different unconfined pressure test in four samples within the Pimienta Formation to obtain the friction angle and cohesion.

Figure 6.25 Static and Dynamic Young's Modulus comparison

Figure 6.26. Dynamic vs Static Young's Modulus and Poisson's Ratio correction at Anhelido-1 (Pimienta Formation).

Figure 6.27. Horizontal Brittleness per azimuth in subvolume around horizontal wellbore side Anhelido-1. Note that the colour bar code is the same for all the maps corresponding to the reservoir zone as attribute map of amplitude RMS extraction which is roughly 80m.

Figure 6.28. Anisotropic brittleness along the horizontal well side (Anhelido-1H)

Figure 6.29. Pore pressure Prediction using Eaton approach.

Figure 6.30. (A) Crossplot Density/Velocity at Anhelido-1 depth range (1500-2200m) to understand overpressure mechanism; (B) Gamma-ray log and geological column; (C) Representative seismic line, (1) Pimienta and Olvido Formation), (2) Upper Cretaceous and (3) Lower Cretaceous.

Figure 6.31. Pore pressure corrected using Atashbari et al (2012) approach.

Figure 6.32. Volumes of stress field around Anhelido-1 and Anhelido-1H; A) Pore pressure volume; B) Minimum stress (S_{hmin}) volume; C) Maximum stress (S_{hmax}) volume; D) Vertical stress (S_v) volume.

Figure 6.33 Representative arbitrary line across the drilling navigation of minimum principal stress and the hydraulic treating stages at Anhelido-1H

Figure 6.34. Comparison of treating pressure (Fracture Closure Pressure FCP) of the entire length in the horizontal wellbore at Anhelido-1H (17 stages) and the minimum principal stress volume calculated from inverted data.

Figure 6.35. Crossplot combination of Young's Modulus and Differential Horizontal Stress Ratio subdivided into three main zones.

Figure 6.36. A) Inverted Young's Modulus in GPa; B) Crossplot combination of inverted Young's Modulus and Differential Horizontal Stress Ratio (DHSR). Green colour code (Brittle fracture swarm will occur for best case), Yellow colour (Brittle but not the best case), and Gray less brittle worst case.

Figure 6.37. Horizontal wellbore storage (Anhelido-1H); A) Flow geometry to and horizontal well and flow regimes (modified from Kazan, 2015); B) Geometry of induced 17 fractures along horizontal wellbore Anhelido-1H; C) Pressure Transient Analysis (derivative of reservoir pressure) with two pressure stabilities and a slope of $\frac{1}{2}$ of the entire hydraulic treating tests across horizontal well side.

List of Tables

Table 1.1 Attributes used to characterize different scales of fractures; seismic anisotropy is the only one of the methods for sub-seismic fractures.

Table 1.1 Attribute properties to assess reservoir characterization in unconventional play and the combination of them to see the 3D spatial overlap.

Table 2.1. XRD data table for the project in two wells Anelido-1 and Serbal-1 respectably.

Table 2.2. Summary of reservoir conditions, mineral composition, and microstructural observations of gas shale samples including Pimienta Formation (modified from Zoback, 2009).

Table 3.1. List of Data set used in the project area.

Table 3.2. Acquisition parameters in the Anhelido 3D Seismic survey

Table 3.3 Azimuthal sectors

Table 4.1. Symmetry systems and its fracture properties caused by cracks in an isotropic background. Crack set refers to a set of parallel cracks, or a distribution of crack orientations symmetrical direction (Winterstain, 1990).

Table 4.2. Thomsen's parameters estimation using Backus averaging from well-log data.

Table 4.3 Earth model at Anhelido-1 depth: 2113 m and Serbal-1 depth: 2908m.

Table 4.4. Observations of the crack density effect and aspect ratio on anisotropic parameters at Anhelido-1 within Pimienta Formation.

Table 4.5. Observations of the crack density effect and aspect ratio on anisotropic parameters at Serbal-1 within Pimienta Formation.

Table 4.6. Elastic stiffness coefficient in VTI mode from the experiment.

Table 4.7. V_p' and E_N' are estimated from P-wave velocities propagating orthogonal and parallel to the fractures and the wave parallel to the fractures regarded to lucite block.

Table 4.8. Rock mechanics data within Pimienta Formation, static measurement of Young's Modulus and Poisson's ratio.

Table 4.9. Summarizes the calculations for crack density from crack porosity and aspect ratio at different confining pressures within Pimienta Formation. All these values are smaller than 0.1, which is the theoretical limit of validity for Hudson's (1981) model with a volumetric distribution of cracks.

Table 4.10. Effective elastic constants stiffness based on different approximations for Anhelido-1 at depth 2113m.

Table 4.11. Effective elastic constants stiffness based on different approximations for Serbal-1 at depth 2908m.

Table 5.1. Elastic properties of different constituents of shale gas reservoir used in rock physics modelling modified (Mavko et al., 2009) within the Pimienta Formation.

Table 5.2. (A) Elastic properties (e.g., Bulk and Shear moduli) at Anhelido-1 and Serbal-1 (reservoir zone) using mineral proportion components X-ray diffraction (XRD).

Table 5.3. Voigt and Reuss bounds for Anhelido-1 showing differences between kerogen filled and non-kerogen filled fracture cases.

Table 5.4. Values used to constraint the AVAz result of anisotropic gradient this Covariance Matrix describes the amount of variance between V_p , V_s , and density and their correlation using the well-log data from the vertical wellbore Anhelido-1.

Table 5.5. Values used to constraint the AVAz result of anisotropic gradient this Covariance Matrix describes the amount of variance between V_p , V_s , and density and their correlation using the well-log data from the vertical wellbore Anhelido-1.

Table 5.6. Azimuthal RMS velocity information (Slow & Fast) and the azimuth of polarization of fast velocity in the horizontal wellbore Anhelido-1H for all the hydraulic design stages.

Table 5.7. Azimuthal RMS velocity information (Slow & Fast) and the azimuth of polarization of fast velocity in the horizontal wellbore Serbal-1H for all the hydraulic design stages.

Table 5.8: Parameters for modelling in Hampson & Russell software at Anhelido-1.

Table 5.9. Information of microseismic events along the 11 stages at the horizontal side of Well-1H

Table 6.1. Dataset subdivided in four azimuth sectors and the incidence angle for each sector. (e.g., near, mid, far, and Ultra-Far)).

Table 6.2. Mechanism of the overpressure and description.

Table 6.3. Pore pressure mechanisms.

Table 6.4. Stress variations with depth (after Zoback)

Table 6.5. Parameters for DHSR to assess optimal hydraulic fracturing locations through seismic data (Gillot, 2014 (Baker Hughes & CGG alliance)

Table 6.6. Dynamic & Static moduli comparison at Anhelido-1

Table 6.7. Minimum and maximum values of vertical and horizontal Poisson's ratio respectively (from inverted volumes).

Table 6.8. Comparison from hydraulic treating test (Fracture Closure Pressure FCP) and minimum principal stress from the inverted data along horizontal side of Anhelido-1H and Anhelido-1.

1. Introduction

1.1 What is a fracture?

Fractures are ubiquitous in reservoirs, both conventional and unconventional (Nelson, 1985; Gale et al. 2014). They exert a significant role in primary and secondary hydrocarbon migration (Cartwright et al. 2007; Abu Mahfouz et al. 2020) and most importantly in the production of oil and gas from fractured reservoirs, especially that where primary permeability (matrix) is low, such as carbonate reservoirs or shale reservoirs.

There are two types of fracture, shear fractures and opening mode (tensile) fractures (Prince, 1966; Nelson, 1985). Shear fractures form under differential stress conditions when the shear strength of a rock is exceeded. Opening mode fractures form when tensile strength is exceeded and there is sufficient tensile stress to allow propagation of an open aperture fracture (Price, 1966; McGarr and Gay, 1977). This process can be achieved by high fluid pressures in the subsurface, in which case the opening mode fractures are referred to as hydraulic fractures (see Gale, 2014 for review). Fractures of Mode I type (i.e., opening mode) in mudrocks are commonly attributed to elevated fluid pressures in the formation (Hooker et al. 2019). However, the origins of natural fractures set in mudrock include (Gale et al, 2014):

- Stress perturbations, tectonics
- Burial History, hydrocarbon generation (see Abu Mahfouz et al. 2020), and other diagenetic processes (Shin et al. 2008)
- Stress release during uplift (Prince, 1966)

The presence of fractures in geologic formations is critical for a number of reasons. Firstly, they affect the bulk permeability (Nelson, 1985; Neuzil, 1994; Matthews, 2015). Secondly, they affect the bulk strength of the formation (Fossen, 2016). Thirdly, they can host significant mineral deposits through the formation of fracture filling minerals (Nelson, 1985). However, they are hard to detect using remote methods, and direct observation through drilling is expensive, and sometimes after the event,

or post facto, and can lead to costly errors. Cores are the most reliable means of characterising subsurface fracture distributions but are limited by the 1D geometry of the borehole, and often wide spacing between sample locations (see for example, Al Fahmi et al. 2020), and even image logs do not provide fully reliable representations of fracture geometry and spacing (Al Fahmi et al. 2018). Hence the rationale for this thesis: to explore new methods for fracture characterisation using seismic methods. A better understanding of fracture distribution and impact on flow characteristics is fundamental in unconventional reservoirs (Sarkar and Tozkoz, 2004). In both core samples and analogous outcrop observations, there is abundant evidence of calcite veins developed within the Pimienta Formation. Most of the observed mineralised fractures are sub-vertical in orientation and somewhat deformed (Figure1.1).

Fracture development in the Pimienta Formation is the main focus of this research project, hence these observations justify the attempt to characterise the fracture system using geophysical techniques.

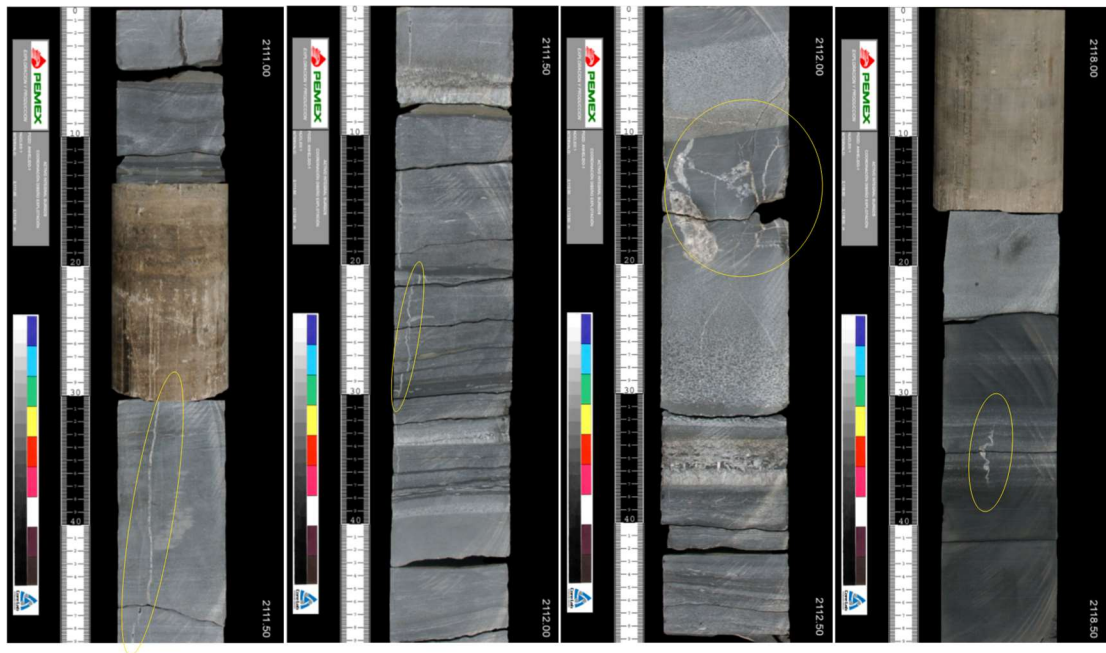


Figure1.1 Natural fractures within Pimienta Fm from cores taken in the well Anhelido-1 (PEMEX E&P, 2012). The fractures are mineralised (veins) and are relatively sub-vertical and filled with calcite.

1.1.1 Scale of fractures

Fractures cannot be identified using conventional observations of seismic reflection data (Juhlin,1998). The seismic resolution limits mean that only faults (with significant displacements of meters and more) can be observed directly through offset of stratal reflections. However, the identification of fractures with dimensions and displacements (in centimeters) below the seismic resolution can still be made using advanced techniques deployed on the seismic data.

Small displacement shear and tensile fractures cause changes in seismic wave propagation. Scattering of the incident seismic energy may be related to fractures, thereby attenuating the amplitude of higher frequencies (Boadu et al., 1996). Even small numbers of fractures may affect the seismic energy propagation. Thereby, seismic methods can be used to locate fracture zones in rocks that may act as reservoirs or to enhance the permeability of tight reservoirs.

Fracture information detected by seismic data can be regarded as an additional attribute and as many other attributes, should be interpreted in a proper geological context (Bush, 2010) (Table 2.1).

Scale	Geological feature	Seismic observation	Data Analysis
Micro-Scale	Diffuse fractures	Seismic Anisotropy	Anisotropy Analysis
Meso-Scale	Fracture corridors	Subtle discontinuity	Fracture cluster analysis
Macro-Scale	Faults	Dislocated horizons	Geometrical attributes Ant-tracking

Table 2.1 Attributes used to characterize different scales of fractures; seismic anisotropy is the only one of the methods for sub-seismic fractures.

In a fractured reservoir, the dominant impact on flow properties is from fracture spacing, dimensions and, for opening mode fractures, the aperture (Nelson, 1985; Patwardhan et al. 2016). The fracture aperture is the physical separation of fracture walls (Fossen 2010). The geometry of this equivalent wall separation is an indicator of roughness where the fluid can flow and is a crucial parameter for the estimation of fracture permeability and fracture porosity (Al Fahmi et al. 2018; Wennberg et al., 2015).

Fracture apertures are not considered to be constant during the geological evolution due to the potential for precipitation or dissolution of minerals from the wall of the fracture. Only limited research has been undertaken on the fluid condition and mineral interactions that lead to the evolution of fracture aperture (Olsen and Laubach, 2009; Hooker et al. 2009). Fluids involved in the fracturing process are often oversaturated with respect to a locally dominant mineral phase and these fluids can cause precipitation in the fractures prompted by localised changes in pressure-related saturation leading to fracture sealing. This process can reveal the history of how the fracture was formed and under what geological conditions (Jones and Detwiler, 2016). The rate of mineral precipitation depends on many factors such as fluid saturation, flow condition, temperature, and host rock mineralogy (Morse and Mackenzie 1990; Lee and Morse, 1999; Dawe and Ahang, 1997; Zhang and Dawe, 1998).

1.2 Geophysical description

Geophysical methods that probe deeply into the subsurface have a reduced ability to resolve the locations of fractures. The fractures are below seismic resolution; hence they are generally neglected in fracture studies using seismic methods (Cui et al., 2018).

The information of near-surface fracture distributions and characteristics is commonly provided by outcrops (David, 2008), but it is challenging to extrapolate accurately to depth in the oil industry. Image logs such as the FMI log are commonly used to characterize fracture aperture down to the order of microns (Tiab and Donaldson, 2015). Other petrophysical logs acquire information from the reservoir at high spatial resolution of decimetres (Rider, 2002).

During the 1980s and 1990s shear-wave splitting was an emerging methodology for fracture studies (e.g., Alford, 1986; Lynn and Thomsen, 1986, 1990; Majer et al., 1988; Queen and Rizer, 1990). When a shear wave enters an anisotropic media such as a fracture zone, it splits into polarized shear waves with the faster one travelling parallel to the fractures and the slower one moving perpendicular

to the fractures. This shear-wave splitting phenomenon leads to a time difference between the fast and slow shear waves within a layer, thereby yielding information on the density and orientation of fractures (Alford, 1986; Lynn and Thomsen, 1986, 1990).

Classical seismic attributes have assisted in the geological understanding of many types of discontinuity, but they are hampered by vertical resolution (Williams et al., 2017). Enhanced imaging, such as blending of attributes, has helped improve the lateral understanding of fracture patterns. Nonetheless combining seismic data and borehole in a distinct workflow, it has become possible to identify overlaps and misalignments, which in turn has assisted in the identification of discrete structural patterns not previously recognized because of the seismic resolution gap.

Data conditioning is an essential process in seismic analysis of fractures for noise cancellation. Spectral enhancement is used to improve reflector continuity and vertical resolution. Multi-attribute analysis can be optimized for detection of small scale structural edges through interpretation of discontinuities in amplitude, phase and orientation, and is particularly effective where these attributes are blended. These methods often allow subtle fault and fracture responses expressed by different styles of seismic discontinuities to be illuminated (Imran et al., 2021).

Conventional seismic methods for fracture detection rely on the measurement of azimuthal anisotropy, coherency analysis other attributes. The use of seismic data is useful in the identification of fractures in many reservoirs throughout the world (Roberts et al., 2001; Smith and McGarrity, 2001; Gray and Head, 2000; Hall et al., 2000; Gray et al., 1999).

Fracture models have been developed from the elastic effective medium approach and information of well logs can be used to build a synthetic image of amplitude reflection trough azimuth. The three most widely employed models are the Hudson, and Linear-slip Models. These allow us to visualise the effect of fractures on seismic information and to reveal the degree of anisotropy present in the rock.

Seismic anisotropy is defined as a condition when the elastic properties measured at the same location change with direction of wave propagation, as opposed to isotropic if there is no change (Sheriff,

2002). In many cases seismic data is based on the assumption that the subsurface behaves seismically isotropically. Sheriff (2002) defined seismic anisotropy as “a variation of a physical property depending on the direction in which it is measured” while Thomsen (2002) defined anisotropy as “the dependence of seismic velocity upon angle”.

In seismic processing, analysis of anisotropy is needed to enhance the seismic image. Knowledge of the anisotropy parameter also helps us to understand rock properties. Anisotropy has to be taken into account because it may induce errors in seismic processing in the layered stratigraphy of sedimentary basins.

Seismic anisotropy is typically associated with three factors when we consider this topic in the context of unconventional hydrocarbons, namely a shaley host rock, thin layering or bedding of the host rock, and fractures within the host rock. The challenge with interpretation of anisotropy is to assign the property to these different elements and hence provide the understanding of physical linkage and quantitative relationships between conventional and anisotropic rock properties (Li, 2002). The classical paradigm is that when burial compaction increases the seismic anisotropy increases (Pervukhina and Rasolofosaon, 2017), and from this concept comes my focus in this thesis on seismic detection of fractures in shale.

One of the most advanced techniques to identify fractures in subsurface formations is the AVAz (Amplitude versus amplitude and azimuth) method, which is gaining popularity among those researching fractured reservoirs. In Chapter 4, I will describe this method in detail and demonstrate its application for the detection of fracture patterns using the subsurface azimuthal 3D seismic data provided by PEMEX for this project.

The isotropic AVO (Amplitude versus offset or Angle) analysis is problematic as the reflection does not only depend on acoustic impedance, in fact, but it also depends on the incidence angle (Bortfeld, 1961). It is used in the oil industry as an essential tool to detect hydrocarbons in the subsurface (Figure 2). In the interpretation of AVO anomalies, it is typically expressed as an increment of amplitude for

sedimentary rock, and it is evident when the reservoir is acoustically ‘soft’ with a low acoustic impedance value.

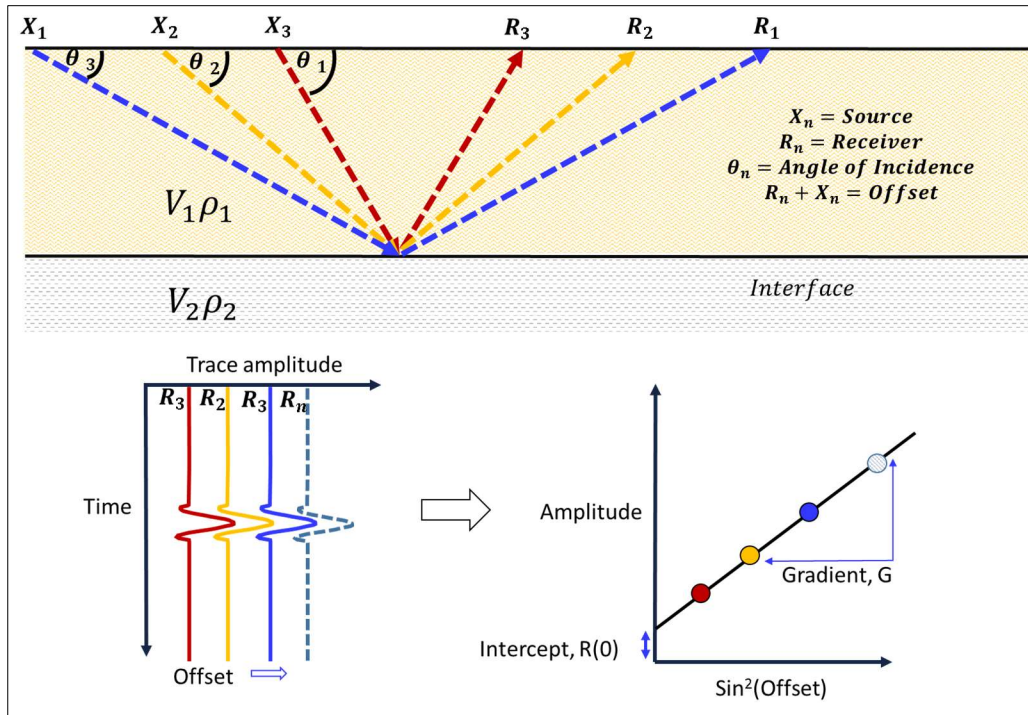


Figure 1.2 Design of sources and receivers in seismic acquisition and the effects of amplitude in the trace response through the angle of incidence.

Several approaches for AVO have been developed throughout its history since the original approach of Karl Zoeppritz, for example the works of Bortfeld (1961), Aki et al. (1976), Hilterman (1983), and Shuey (1985). Rutherford and Williams (1989) introduced the AVO classification of seismic reflection from the interface assuming shales and underlying gas sands. This classification is now a standard used in the oil industry.

Castagna and Swan (1997) developed and proposed an AVO graphical cross plot where the reflectivity of normal-incidence is plotted against a measure of the offset dependent reflectivity. By using this cross plot, they defined the characteristics of AVO classes using their terms of Intercept and Gradient in AVO.

AVO Class behaviour of various gas sands in terms of AVO intercept and gradient is depicted in (Figure 1.3):

- I. Higher impedance than the overlying unit.
- II. The same impedance as the overlying unit.
- III. Lower impedance than the overlying unit.
- IV. Lower impedance than the overlying unit.

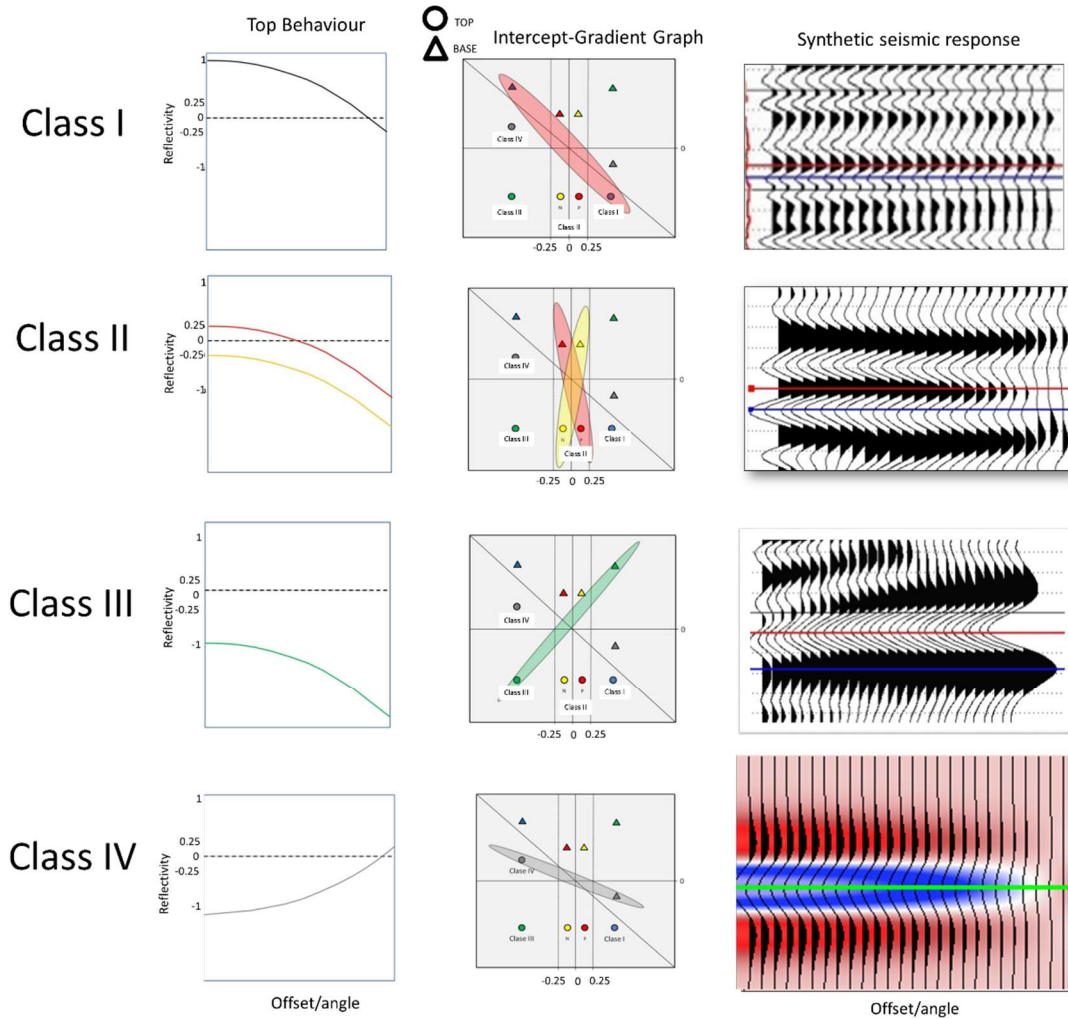


Figure 1.3 AVO/AVA class representation chart, the first column of graphs represent the amplitude gradient curves depending on the AVO/AVA class ,the second column is the crossplot of the top and base of the reservoir defining the type of AVO/AVA class and finally the third column the synthetic seismic response representation of each individual AVO/AVA class e.g. Class I starts with high amplitude and reduces with offset, Class II starts with low amplitude and increases with offset, Class III starts with high amplitude and increases further with offset, Class IV starts with high amplitude and decreases with offset.

In contrast, the Azimuthal AVO/AVA (AVAz) involving anisotropy is the analysis of incidence angle and azimuthal amplitude variations of reflection coefficients from an interface layer and it measures

change in elastic properties. This is useful when attempting to characterize natural fractures or differential stress in a reservoir as can be seen in Figure 4. The difference from normal AVO in common azimuth is that takes into consideration just a narrow azimuth and the variable azimuth for anisotropic AVO/AVA that is performed 360° is shown in (Figure)

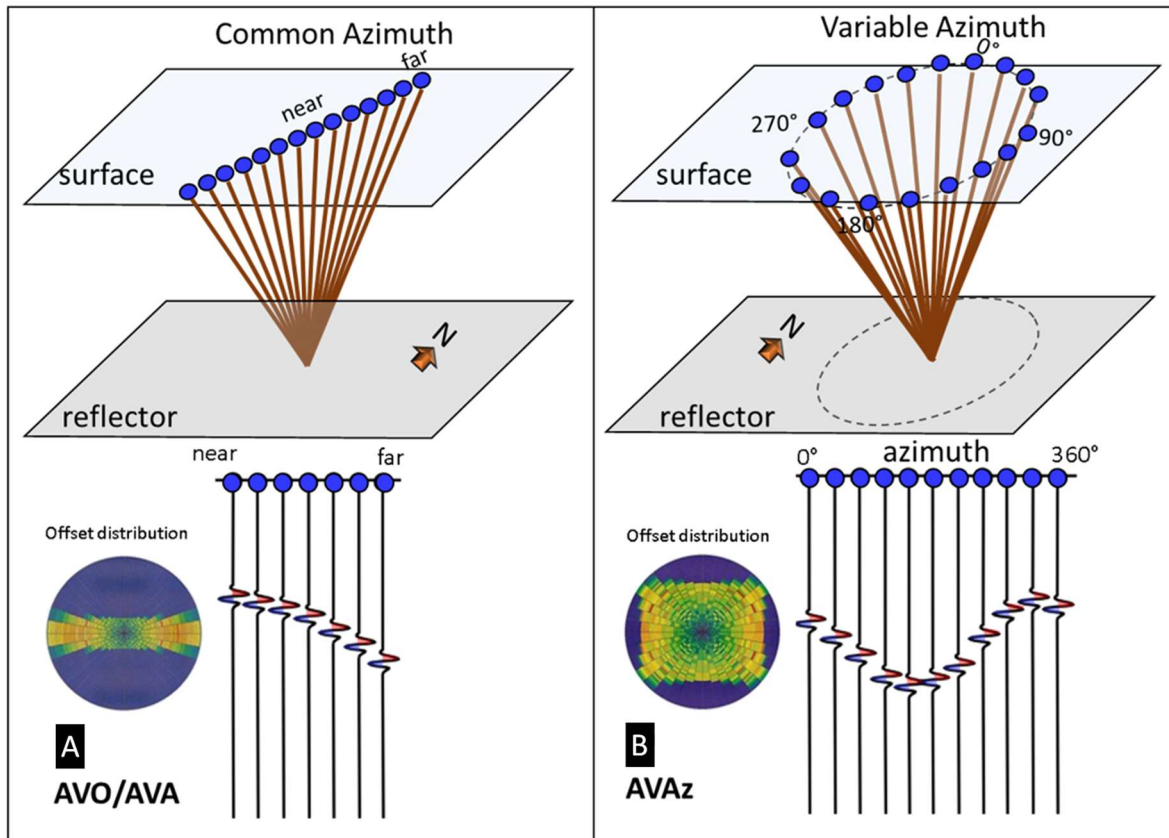


Figure 1.4 A) Example of narrow common azimuth- versus B) Wide-azimuth templates and offset distributions. X offset distance in rose diagram.

Azimuthal AVO/AVA is the analysis of the azimuthal amplitude and incidence angle: it measures changes in elastic properties at an interface and is widely used in the oil industry to characterize naturally fractured reservoir including the differential stress. Anisotropy is a critical attribute for the characterization and detection of fractured media. In many cases it can be related to the rock properties or fabric (e.g., preferred orientation of minerals within the rock). For example, when the rock fabric of minerals is aligned parallel to the bedding this makes it a type VTI (vertically transverse

incidence) anisotropy with the vertical axis of symmetry (Figure 1.5A). Vertical fractures orthogonal to the bedding produce an HTI (horizontally transverse incidence) medium in the long-wavelength limit (Schoenberg, 1986) (Figure 1.5B).

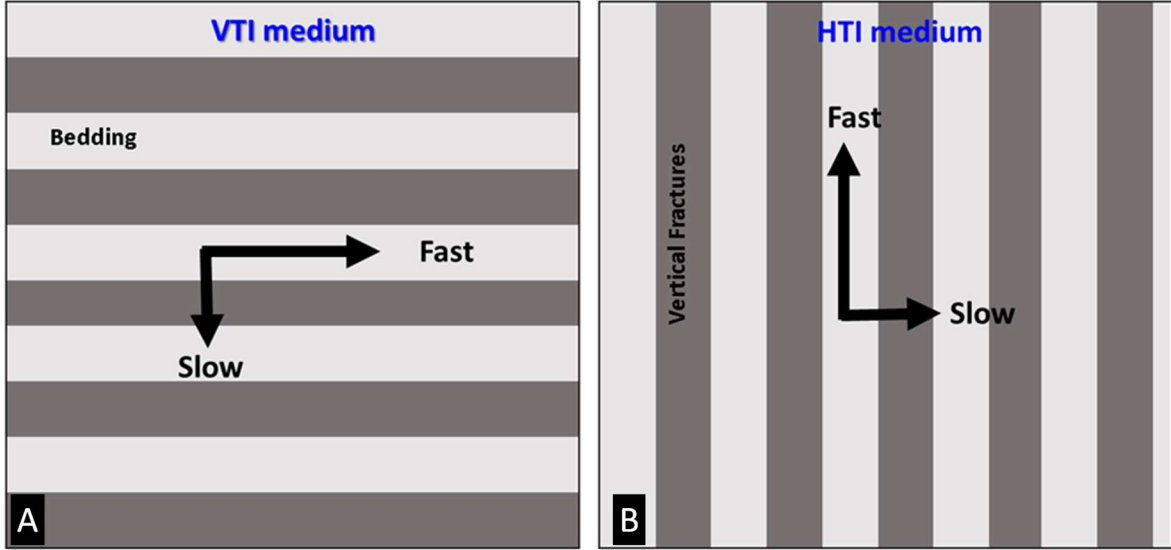


Figure 1.5 A) VTI anisotropy parallel to the bedding and B) HTI is representing vertical fracturing orthogonal to the bedding in the symmetry of isotropic material.

The wave propagation behaves homogeneously and travels equally fast in all directions and is addressed by the stiffness matrix, which includes five independent constants.

$$C^{VTI} = \begin{bmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\ C_{12} & C_{11} & C_{13} & 0 & 0 & 0 \\ C_{13} & C_{13} & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{44} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{66} \end{bmatrix} \quad (1.1)$$

Where $2C_{66} = C_{11} - C_{12}$

In Thomsen's notation the stiffnesses can be parametrized as anisotropic parameters:

$$\varepsilon^{(V)} = \frac{C_{11} - C_{33}}{2C_{33}} \quad (1.2)$$

$$\gamma^{(V)} = \frac{C_{66} - C_{44}}{2C_{44}} \quad (1.3)$$

$$\delta^{(V)} = \frac{(C_{13} + C_{44})^2 - (C_{33} - C_{44})^2}{2C_{33}(C_{33} - C_{44})} \quad (1.4)$$

ε is the fractional difference between vertical and horizontal P velocities; i.e., it is the parameter usually referred to as the anisotropy of a rock (Thomsen, 1986). Regrettably, the horizontal velocity is rather hard to measure. γ is the half fractional change in the S-wave velocity and is more difficult to interpret but contributes in an essential way to near-vertical P-wave speed variations.

The velocities are independent of the wave propagation direction in isotropic material and are given by three pure modes (P, SV, SH waves).

$$V_{Pvert} = \sqrt{\frac{C_{33}}{\rho}} = V_p \quad (1.5)$$

$$V_{SVvert} = \sqrt{\frac{C_{44}}{\rho}} = V_s \quad (1.6)$$

$$V_{SHvert} = \sqrt{\frac{C_{66}}{\rho}} = V_s \quad (1.7)$$

The Vertical Symmetry axis (VTI) is the most straightforward physically realizable anisotropic system in hexagonal symmetry anisotropy (Figure). Hexagonal symmetry has an axis of cylindrical rotational symmetry, which implies that the properties of the medium in a given direction depend only on the angle between that direction and the symmetry axis direction.

Derivations of phase velocities in Thomsen weak anisotropy limit can be found in many sources, including Thomsen (1986, 2002) and Rüger (2002) and for VTI can be expressed as a function of angle from the vertical direction as:

$$V_p(\theta) \cong V_p(0)(1 + \varepsilon \sin^2 \theta - (\varepsilon - \delta) \sin^2 \theta \cos^2 \theta) \quad (1.8)$$

$$V_{sv}(\theta) \cong V_s(0) \left(1 + \left[\frac{V_p^2(0)}{V_s^2(0)} \right] (\varepsilon - \delta) \sin^2 \theta \cos^2 \theta \right) \quad (1.9)$$

And

$$V_{sh}(\theta) \cong V_s(0)(1 + \gamma \sin^2 \theta) \quad (1.10)$$

In terms of stiffness constants for VTI $V_p(0) = \sqrt{C_{33}/\rho_0}$ and $V_s(0) = \sqrt{C_{44}/\rho_0}$, where C_{33} , C_{44} and ρ_0 are the stiffness of cracked medium and the density of the host rock. The Thomsen's anisotropic parameters are in the eq. (1.2), eq. (1.3) and eq. (1.4). These parameters γ , ε , δ , play essential roles in the velocities given by equations (V_{sh} , V_{sv} , V_p), when the anisotropy is significant, as would be the case in fractured rocks when the crack densities are high. If fracture densities are very low, then the SV shear wave will really have no dependence on the angle of the wave propagation.

For HTI media resulting from vertical, rotationally invariant fractures, (Bakulin, Andrey et al. 2000; Rüger, 2002) gave approximate expressions for ε , γ , and δ . Using the Voigt notation C_{ijkl} , the stiffness matrix can be written as:

$$C^{HTI} = \begin{bmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\ C_{12} & C_{11} & (C_{33} - 2C_{44}) & 0 & 0 & 0 \\ C_{13} & (C_{33} - 2C_{44}) & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{55} \end{bmatrix} \quad (1.11)$$

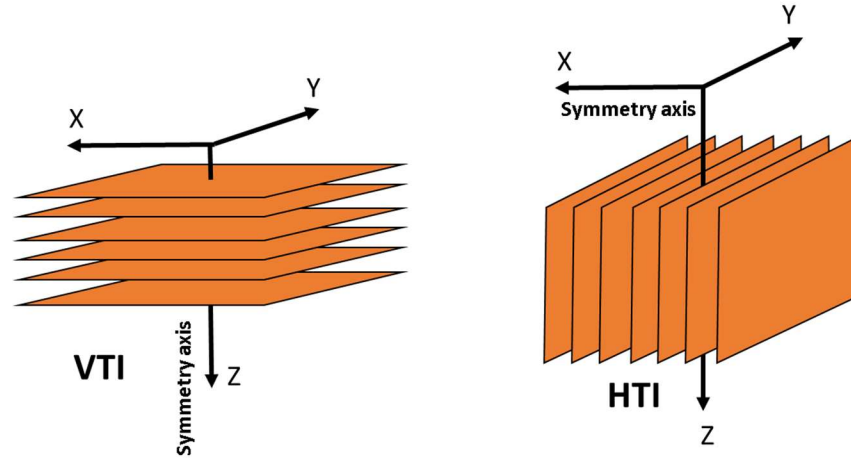


Figure 1.6 Symmetry axis between VTI&HTI media.

For this section, I have developed code as a graphical user interface to estimate the anisotropic Thomsen's parameters values for VTI and HTI, including HTI-Rüger called AnisoModR1 (Figure 1.7). It is a tool to handle well log data to compute the anisotropic parameters based on the velocity P and S from sonic logs.

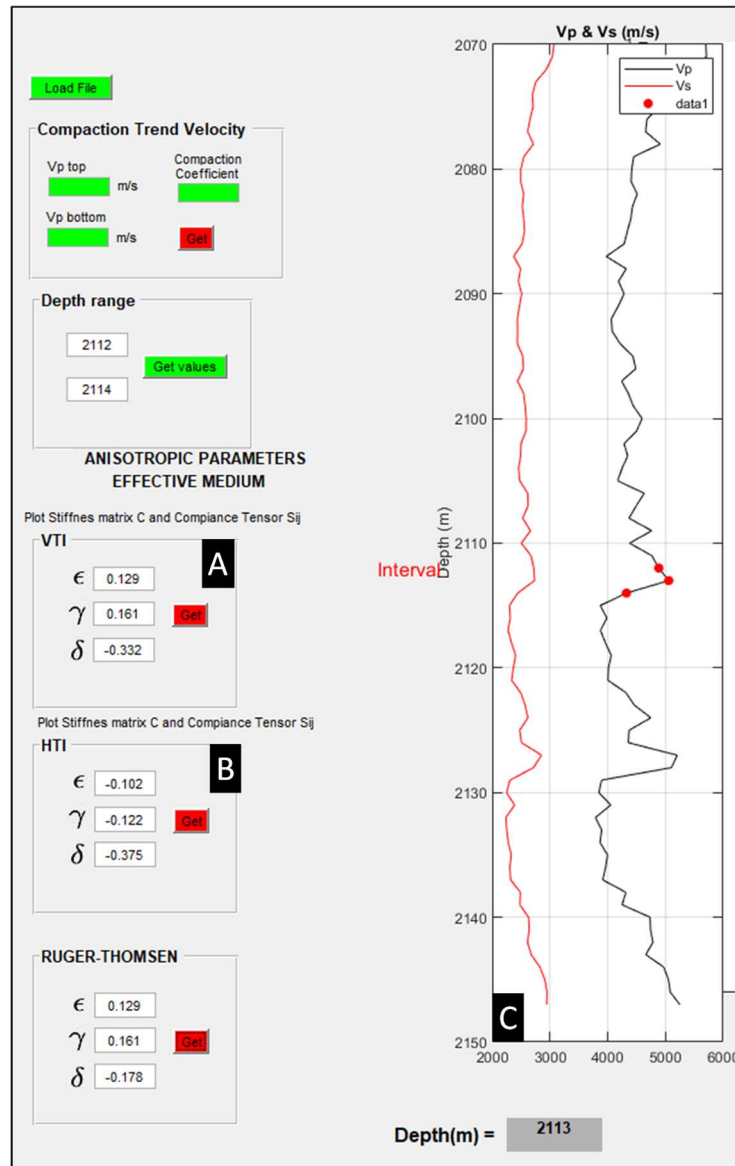


Figure 1.7 AnisoMOD R1 user interface coded in MATLAB to compute the stiffness matrix for A) Anisotropic parameters in VTI; B) HTI media; C) Vp and Vs plot within Pimienta Formation (2113m).

1.3 Background to this study: Recent research on fracture detection using geophysical methods.

Sub-seismic fracture detection techniques are the focus of this study, and they will be described in the following chapters. It is helpful to set my work in the context of many recent advances in this field.

One of the most advanced technics to identify fractures is the AVAz (Amplitude versus amplitude and azimuth) method, which is gaining popularity among those researching fractured reservoirs. In Chapter 5, I will describe this method in detail and is one that I will apply for the fracture pattern detection in the subsurface 3D seismic data of this project. Previous studies (Rüger, 2002) have shown that the azimuthal variation of the AVO gradient is a function of the shear-wave splitting parameter γ , and the anisotropy parameter describing P-wave anisotropy for near-vertical propagation in the vertical plane containing the symmetry axis. This method has been successfully applied to fracture detection in unconventional plays and there has been significant progress in advanced geophysics for most existing P-wave AVO algorithms in wide-Azimuth data.

Bakulin et al. (2000), Jilek, (2002), DeVault et al. (2002) suggested that the stability of AVO analysis can potentially be improved using the combination of wide azimuths. However, Hall and Kendall (2003) assumed a single set of aligned penny-shaped cracks from the resulting of HTI medium. Nevertheless, Gray et al. (2002) and Todorovic-Marinic (2004) report many case studies of HTI-medium based on azimuthal AVO, where the estimated fracture direction was in good agreement in contrast with other methods. Subsequently, Maultzsch et al., (2003), Tsvankin (2005), and Gray (2008) found that the directionally varying geometrical spreading above the reflector, in particular for wide-azimuth data, causes significant distortions in amplitude for anisotropic media. Inversion of the azimuthally P-wave AVO gradient for the crack density estimation is non-unique without additional information.

Marret et al. (2007) argued that fractures commonly are nearly vertical and hence vertical wells are unlikely to detect many fractures and correctly sample the full fracture population. Finally, Liu et al. (2016) claimed that the characterization of fractures based on the concept of seismic anisotropy is widely used in the industry.

Amplitude versus azimuth AVAz has gained popularity as a means of predicting fractures, e.g. fracture intensity and orientation using seismic data sets sorted in azimuth. Building on from the idea

that fractures can be detected using azimuthal AVO/AVA, I will focus on the application of Rüger HTI media to successfully infer fracture properties in the rock fabric as a practical methodology for unconventional reservoir characterization using azimuthal seismic data. Rüger HTI media is represented by vertical fractures embedded in the anisotropic layer, which will be explained in Chapter 5.

1.4 Unconventional Reservoirs

Shales can function both as an unconventional reservoir and as a source rock at the same time, but due to their very low permeability it is necessary to apply artificial fracturing technology ('Fracking') to stimulate the rock and create high conductivity fractures to recover the hydrocarbons (Figure). Shale oil and gas are precisely the same product as oil and gas natural from conventional extraction, the main difference being the reservoir properties: conventional hydrocarbon development exploits higher permeability reservoirs, whereas unconventional development targets and exploits ultra low permeability reservoirs such as shales, cemented carbonate mudstones or silty shales (Law and Curtis, 2002; Curtis, 2002; Gale et al., 2014).

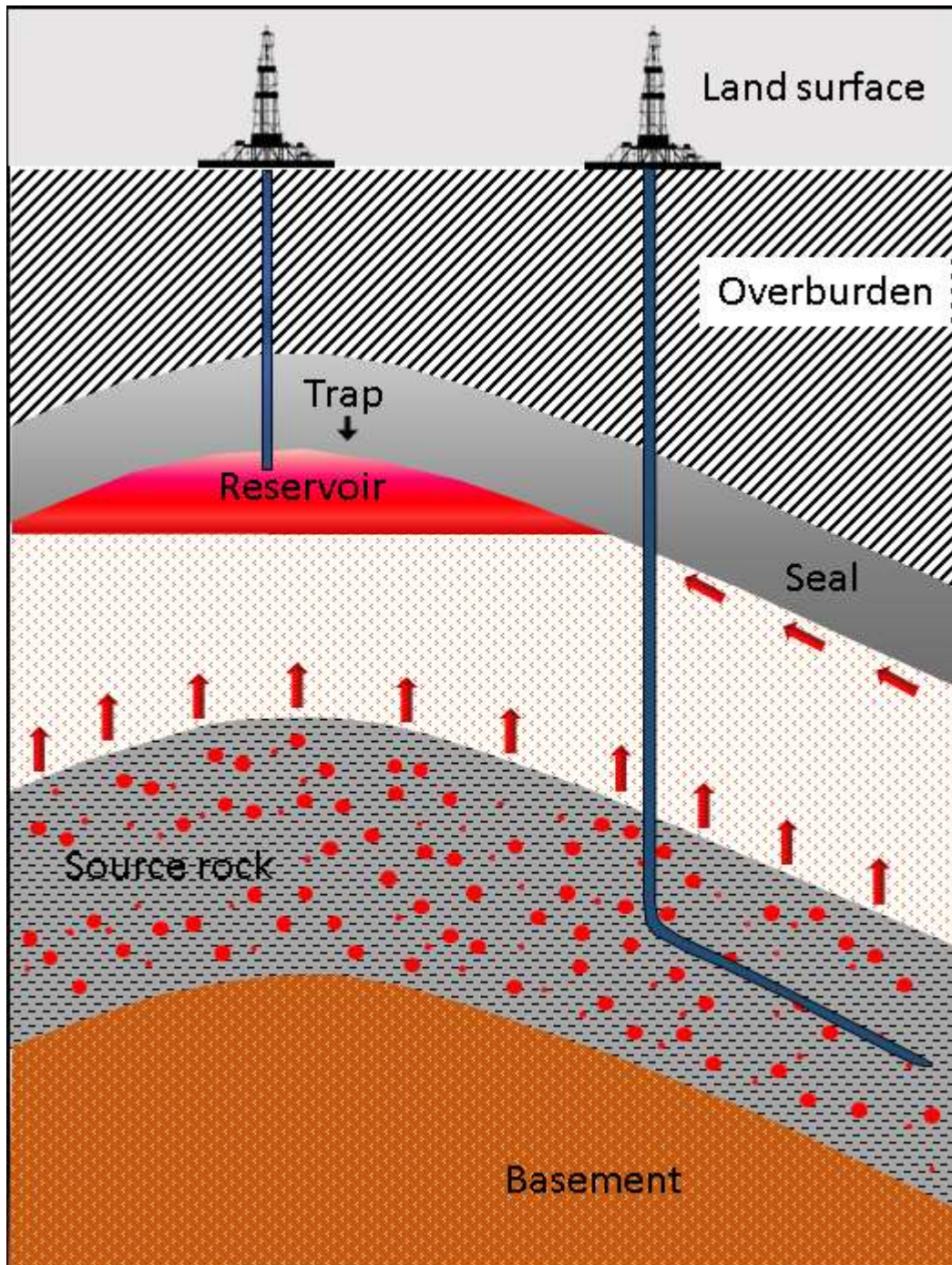


Figure 1.8 Diagram of conventional reservoir and unconventional shale oil/gas reservoir in exploration.

Prospective shale formations vary significantly in mechanical properties and mineralogical content where the recovery factor can vary from 15 to 35% on average (Xiao, 2017), that makes it a considerable challenge for commercial hydrocarbon extraction to oil companies (Barati et al., 2020).

Geologists have known about gas and oil from shales for decades, but for many years development was not economically viable without a reduced cost base for drilling and fracking horizontal wells. In the past two decades, reduced costs and improved drilling technology for the critical combination of two proven technologies (horizontal drilling and hydraulic fracturing) made shale gas/oil commercially viable (U.S Natural Gas in the Global Economy, 2017).

In the exploration field, a significant increase of hydrocarbon production in recent years has been the result of the expansion of exploitation of shale rock reservoirs, but for that, hydraulic fracturing technology has been the primary production technique for this kind of unconventional reservoir (European Commission Joint Research Centre Institute for Energy and Transport, 2013).

Hydraulic fracturing in shale rocks creates an exceptional amount of fractures where the hydrocarbons can be carried to the wellbore but at the same time an enormous challenge to maintain a long-lasting conductivity through this stimulation, due to the mineral and mechanical composition of the rock (Figure 1.91.9).

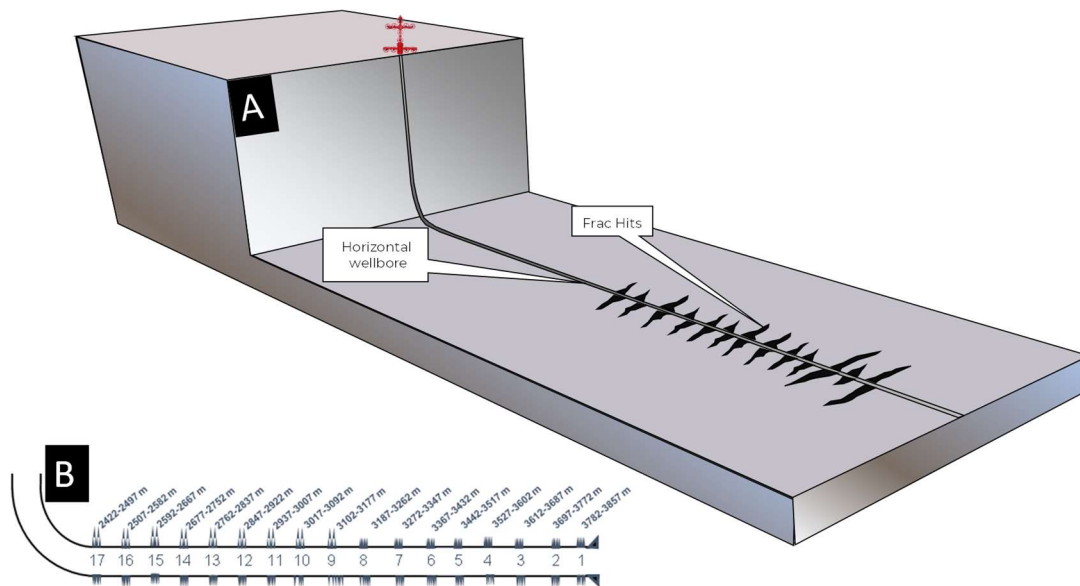


Figure 1.9 (A) Schematic example of ‘fracking’ techniques on the shale reservoir; (B) Horizontal well with 17 hydraulic fracturing stages at Anhelido-1H (PEMEX E&P, 2012) with ~1500 m length.

The importance of the specific mineralogy of shale rocks for the URC (ultimate recoverable resources) is now well known. In particular, relative abundances of quartz, clay and carbonate minerals

determine the efficiency of hydraulic stimulation of shale host rocks (Shen et al., 2017). This is typically explained by a combination of two factors:

- Shales tend to be brittle when it is high in quartz and carbonate percentage and will break and induce fractures providing flow paths from rock matrix to the wellbore.
- When clay contents are high, the shale tends to be ductile and not easily fractured or the fractures close easily after the initial phase, which would mean a significant reduction for fractures with limited flow pathways to the wellbore.

Geological complexity may further dictate the shale gas/oil recovery efficiency from a shale basin and formation. This may arise from:

- High-stress geological features such as thrust faults, basin areas with high lateral stress, which may reduce the permeability and flow capacity.
- Vertically extensive faults can lead to water flow into the shale rock matrix reducing the permeability and flow capacity.
- Networks of faults can be hard to avoid with a regular pattern of horizontal well trajectories and can limit the productive length of an individual horizontal wellbore due to the need to avoid fracking near a tectonic fault (to avoid leakage, fault dilation, or induced seismicity).

Shale rock reservoirs have been actively developed in North America for oil production in the last twenty years (Parraguez, et.al., 2015). For the development of this type of reservoir, geological/geophysical techniques have to be applied to predict areas using a multi-attribute combination to determine the 3D spatial congruence between key parameters shown in Tabla 1.2.

This property of overlapping parameters should be taken into consideration to determine the best prospective areas to design a horizontal wellbore better to minimize the uncertainty and get better results in economic/commercial contexts (Tahmeen et al., 2019)

The challenge is to upscale all these properties from log to seismic scale because with these properties it will be possible to calculate maps distributions representing the ideal overlap of the most prospective regions where all the properties coincide, which are commonly known in the petroleum industry as “Sweet spots”.

Attribute Property	High	Low
Young's Modulus	✓	
Poisson's Ratio		✓
Brittleness	✓	
TOC	>3% (Project area)	<1% (Project area)
DHSR		✓

Tabla 1.2 Attribute properties to assess reservoir characterization in unconventional play and the combination of them to see the 3D spatial overlap.

Multi-attribute relationships between shale properties and elastic parameters are established through rock physical analysis. Then, 3D pre-stack azimuthal seismic inversion is conducted to predict the TOC content, brittleness, and differential horizontal stress ratio. Figure 1.10 depicts the workflow for unconventional reservoir characterization that was developed and will be applied to the project. In this workflow I will re-calculate the TOC and brittleness taking into consideration the anisotropy. Brittleness will be estimated for VTI, HTI media, and TOC using inverted impedances through the azimuth which will be addressed in Chapter 6.

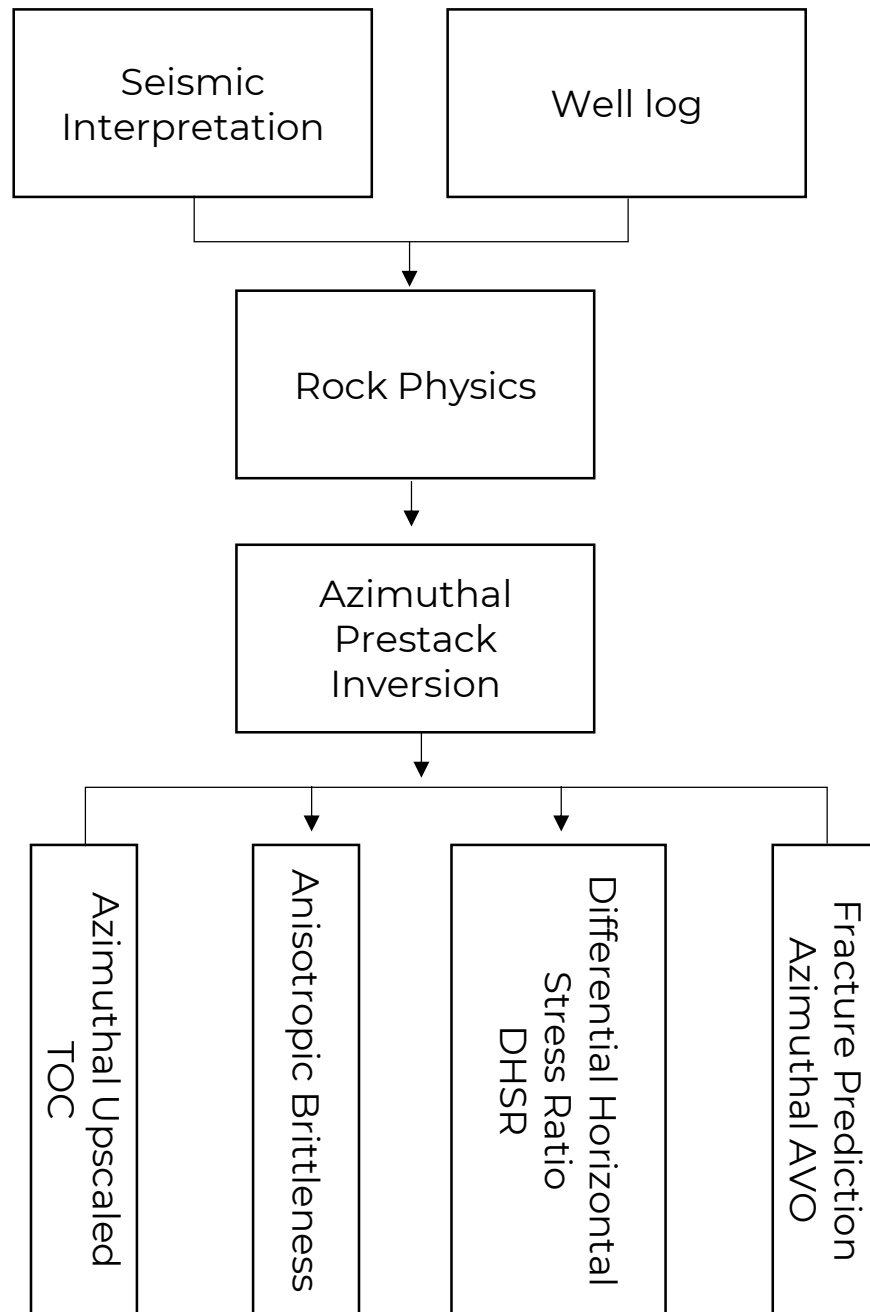


Figure 1.10. Workflow proposed to characterize and assess an unconventional reservoir in shale rocks in this project.

The Unconventional resources in Mexico, could yield more than 400,000 B/d of crude and 1.4 Bcf/d of gas between 2025 and 2040 (International Energy Agency, 2019) which is one-third of current oil production and more than one-third of current gas production.

Just a few test wells have been fracked in Mexico, while the U.S. has had nearly 2 million commercial fracked wells drilled. Mexico has not yet produced shale gas. Even so according to figures from the "World Shale Resource Assessments" reported by (Energy Information Administration, 2019), Mexico ranks seventh worldwide in technically recoverable unproven resources (Energy Information Administration, 2019) this is the last report since Mexico is no longer producing on unconventional resources.

The major unconventional plays in the USA are the Bakken, Eagle Ford, Permian Basin, Marcellus, Anadarko-Woodford, Granite Wash, Niobrara, and Haynesville. These latter two are both in shales of Tithonian age. In contrast, there are only two recognised shale plays in Mexico, the Eagle Ford extension, and the La Casita/Pimienta Formation (Upper Jurassic Tithonian) (Figure 1.11).



Figure 1.11 Shale plays in North America U.S.A (source U.S Energy Information Administration) based on data from various published studies.

According to the 2017-2031 Natural Gas Outlook published by Council of Energy in Mexico (SENER, 2017), the balance of natural gas in the northeast region for 2018-2031 is totally deficient, since in 2016 it represented a production of 747.1 MMcf/d and a demand of 2,499.5 MMcf/d, that is, a deficit of 1,752.4 MMcf/d, which represents 70% of total demand. The said deficit was covered with imports from the United States.

It should be mentioned that this region has an extensive network of import and internment pipelines to other regions of the country, which has allowed it to meet its demand.

It is estimated that only in the Burgos Basin, there are resources (conventional and unconventional) for 67 Tcf of natural gas and 600 MMb of oil.

Besides, in the Sabinas Basin resources are estimated at 68.9 Tcf and 600 MMb, while in the province of Tampico-Misantla for 25.1 Tcf and 32.1 BBo. Therefore, 58% of the Nation's prospective resources are concentrated in the northeast area of the country, and it is expected that they can be developed in the medium term in order to substantially increase the production of natural gas.

1.4.1 Total Organic Carbon (TOC)

The value of TOC in shale formations is a decisive factor for gross prospectivity since it provides an essential indication of the potential for oil and gas generation (Law and Curtis, 2002). Typically, unconventional systems exhibit considerable variability compositionally both vertically and laterally within any given shale reservoir and the higher the value of TOC the more likely is the presence of a sweet spot (Passey et al., 2010). Estimation of TOC from well log data is seen by many authors as a practical approach to counter the problems of sampling from core and cutting samples (Zhoa et al., 2016).

Approaches proposed to establish TOC from well-log data require samples from core data to calibrate its values. The published methods to the estimation of TOC are separated into two categories (Zhoa et al., 2016):

- TOC empirical relations between a petrophysical curve and core information
- TOC separation resulting from crossplot of two petrophysical properties

The second method is used in this project work, the aim of which is to distinguish source rock vs. non-source rock, this section is addressed in Chapter 3.

1.4.2 Brittleness

Another important property is the known as brittleness, which broadly speaking represents the ability of the rock to resist load decreases with increasing deformation. Brittleness is the ability of rock to fracture in function of mineral composition and lithology (Wang and Gale, 2009) (Figure 1.12).

Rickman et al. (2008) proposed using Youngs Modulus (E) and Poisson's ratio (ν) to calculate brittleness. Because elastic modulus can be estimated from wireline logs, therefore this elastic modulus can be extrapolated to the seismic scale. Brittleness is a fundamental parameter that characterises shale units that are prone to fracture during fracking operations and depends on the content of brittle minerals such as carbonate and quartz.

In this project and according to the mineral composition from XRD data, the Pimienta Formation is on average composed of 40% quartz, 39% carbonate, 13% clay minerals and 8 % other minerals. Hence fractures can be created through hydraulic stimulation since this formation fulfills the mineralogical criterion for brittle behavior.

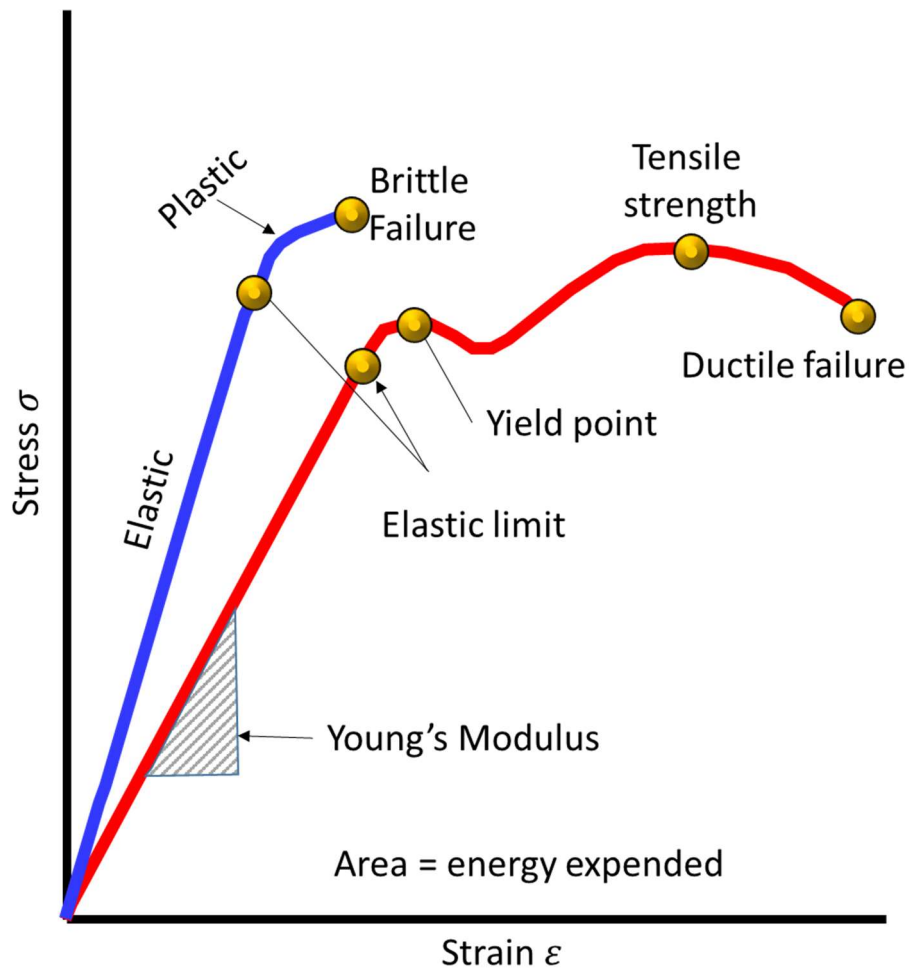


Figure 1.12 The stress-strain curve showing typical yield for brittle materials (blue) compared with ductile materials (red). Stress (σ) is shown as a function of strain (ϵ).

Reservoir characterization consists of detecting and evaluating the characteristics and parameters of the formation that affect the flow behavior, including permeability, porosity, anisotropy, capillary forces and wettability, stratification, failures geological, disagreements, coinage, fracturing and dividing the study area (reservoir) into compartments.

In the characterization of oil fields, the main objective is to know the characteristics of the rocks producing hydrocarbons and the fluids present in the reservoir, both qualitatively and quantitatively (Dake, 1978).

Geophysical well-logging functions to define geological and physical characteristics of rocks, such as lithology, porosity, fluid saturation, and permeability, as well as to identify producing areas,

determine depth and thickness of zones, distinguish between oil, gas, or water in the deposit and to estimate hydrocarbon reserves (Rider, 1990).

Also, well logs are used in oil exploration to correlate areas and assist in the mapping of structures and the development of geological and petrophysical maps.

Geophysical well-logging can be grouped according to the property they determine in lithology (SP, RG), porosity (density, neutron, sonic log P-sonic/S-sonic) and saturation (electrical, induction) logs.

For several wells used within this project, the S-wave log (S-sonic) is not included in the set of elemental logs for reservoir characterization that were made available to this thesis project. The S-wave measurement is extremely important for rock physics analysis in reservoir characterization. Petrophysical conditioning of well log data should be performed to remove artifacts in the data created by drilling (or other) problems during the logging run. The use of the S-wave log in rock physics analysis is essential for determining the physical relationship between the mineral petrophysics, the fluid volume, and the measurements derived from the elastic log suite (density and sonic logs (P-sonic / S-sonic)).

Consequently, rock petrophysics and physics are an iterative workflow that includes the estimation of the wavelet and well correlation to ensure the consistency of the deliberate petro-elastic model, wavelet estimation, model construction and interpretation of the final result. Given the lack of S-wave logs in some wells of the project, in Chapter 3 I will explain in detail how to generate an ‘estimated’ S-wave log by an approach based on multi-attribute linear regression using other well-log data as input in the EMERGE module in the Hampson & Russell rock physics modelling software.

1.4.3 Importance of fractures in unconventional plays in the oil and gas industry

In the past decade, it has been understood that significant amplitude distortions in anisotropic media occur; in particular, for wide-azimuth data and that these might potentially be related to fracture distribution in the layered media (Xiaoxia and Tsvankin, 2007). This is a potentially important finding for unconventional oil and gas reservoirs to improve future exploration by using azimuthal AVO variations for fracture detection. Understanding of the unconventional reservoir is needed to develop an efficient method to determine the most potentially productive regions for example, in the Pimienta Formation in NE of Mexico (this study), to take full advantage of the extraction of oil using hydraulic fracturing and reduce the environmental impact

1.5 Rationale, Scope, Aims and Execution

My research project generally aimed to develop a better understanding of the anisotropy of amplitudes of the Pimienta Formation. This study is based on a high quality azimuthal seismic dataset from the Burgos Basin in the north of Mexico, supplied by my sponsor Pemex Oil Company, specifically for this project. The sponsor explicitly designed the project, and it was necessary to comply with the project goals as a condition of the scholarship award.

More broadly, however, I set out to understand the seismic anisotropy of shale rocks better to improve future exploration by using Azimuthal AVO/AVA for fracture detection, and rock physics to develop a thorough understanding of the reservoir (c.f. Tsvankin & Grechka, 2005).

Based on a literature review on fracture detection, the main scientific questions to be tackled in this thesis are:

1. Is it possible to quantify fractures in shale oil and gas reservoirs using fracture modelling from effective media, geophysical approaches and apply this understanding in particular to the Upper Jurassic shales of the Pimienta Formation?
2. Based on the fracture modelling results, can we estimate the stress field and the rock physics anisotropy by using geomechanical parameters derived from inverted volumes and Azimuthal AVO with more accuracy?

This research work is based on the understanding of anisotropy in shale rocks. High-quality azimuthal seismic data is used for the interpretation and definition of geological characteristics of the study area. There is also information of cores, geophysical well logs that will help to perform rock physics for this type of rocks, RockEval information, which will help to constraint values for further calculations in seismic processes.

The project set out with four main objectives:

1. to detect fractures through advanced techniques such as the azimuthal AVO / AVA in order to find the fracture distribution and orientation.
2. to apply azimuthal seismic modelling using the effective medium theory to estimate the anisotropy parameters using fracture models.
3. to perform anisotropic rock physics and a simultaneous azimuthal inversion.
4. to determine the areas with the highest TOC and brittleness values based on the inverted volumes, as well as the differential horizontal stress.

To achieve the aims of this present research work it was necessary to perform the following tasks:

1. Estimate the TOC and Brittleness index using the empirical equation of Passey for the TOC (Passey et al.1990) and Rickman for Brittleness index (Rickman et al. 2008)
2. S-wave estimation

3. Develop an anisotropic rock physics approaches to understand rock modulus parallel to the bedding and perpendicular.
4. Estimate the amplitude (AVAz) variations for fracture detection and its constraints using well log data.
5. Effective media for fracture modelling using (Hudson, and Linear-slip models) Hudson, 1980; Schoenberg 1980; Sayers, 2007)
6. Compute and take into account the fluid effect using fluid substitution Brown-Korringa formulation applied for anisotropic rocks (Brown and Korringa, 1975).
7. Estimation of anisotropic brittleness based on Young's Modulus and Poisson's Ratio parallel and perpendicular to the bedding (VTI/HTI).
8. Perform an anisotropic seismic inversion using industrial seismic data set.
9. Compute geomechanical volumes such as Young's Modulus, and stress tensor.
10. Characterize shale rocks properties including; fractures, and introducing a novel technique to estimate the TOC variation through the azimuth based on P-S Impedances by adding an extra dimension of the Vernik et al. (2010) equation for TOC content.

1.6 Layout

The thesis is divided in 8 chapters in which have been written a brief introduction of unconventional resources in Mexico and the study area, main results of fracture models, AVAz method for fracture detection, anisotropic brittleness and TOC, conclusion and discussion on the observation seen in the results.

Chapter 1 consists of background information of fractures scales and its importance in unconventional reservoirs, main recent research on fracture detection in the oil industry and methods used in this thesis.

Chapter 2 addresses the geological setting, stratigraphy, petroleum system and the importance of Pimienta Formation as unconventional reservoir for the oil exploration of the main study area.

Chapter 3 addresses azimuthal seismic data, well log and the methods used in this thesis for fracture detection, prediction of the s wave, conventional TOC and brittleness estimation.

Chapter 4 addresses a brief theoretical description of the fracture models in effective media using well log data, azimuthal imaging computation and its differences using codes that I have created for this chapter to better understand the anisotropy within Pimienta Formation.

Chapter 5 azimuthal seismic data set for fracture detection has been used to estimate fracture density and its orientation within Pimienta Formation. A major contribution for anisotropic brittleness in VTI and HTI anisotropy have been done in this chapter, as well as the comparison of different structural methods to detect fractures and its orientation are described.

Chapter 6 presents the major findings of this research address a new approach to compute anisotropic TOC and Brittleness using seismic data inversion and the stress field. The main contribution in this chapter is the addition of an extra dimension (azimuth) into the Lev Vernik equation for the TOC estimation through inverted seismic data mainly P and S impedances, anisotropic brittleness in VTI and HTI calculated in different seismic azimuths as well.

Finally, conclusions based on the present research thesis work are proposed and discussed Chapter 7/8.

2. Geological Setting

2.1. Introduction

This thesis study is based on well and seismic data from the Burgos Basin, NE Mexico. The Burgos Basin is host to two significant unconventional shales, the Upper Cretaceous Eagle Ford Formation and Upper Jurassic Pimienta Formation (Scott et al. 2015). Together they contain a substantial quantity of oil and gas. To determine the most potentially productive regions of the Pimienta Formation, it is necessary to integrate analyses from a wide range of disciplines such as petrophysics, geophysics, and regional geology.

The Burgos Basin is located to the south of the Rio Grande, east of the Burro Salado Arch, northeast of the Sierra Madre Oriental thrust, northeast of Tamaulipas Arch and north of the Tampico-Misantla Basin (Figure 2.1). This latter region contains similar Mesozoic shale targets, and the basin extends offshore, but the thesis study area was limited to the onshore part of the basin. Closely spaced mostly normal faults associated with folds deform the Cenozoic sequence and form conventional hydrocarbon traps (Hernandez-Mendoza et al., 2008).

The Burgos Basin is a rift basin of Mesozoic age. It formed by lithospheric extension during the Jurassic to Early Cretaceous and was associated with salt deposition. Subsequently, during the Late Cretaceous, it was subject to compressional tectonic regime during the Mexican Orogeny (Fitz-Díaz et.al., 2017). The last major tectonic phase involved deformation by strike-slip faulting during the Oligocene along the Rio Bravo left-lateral fault zone (Flotte et al., 2008).

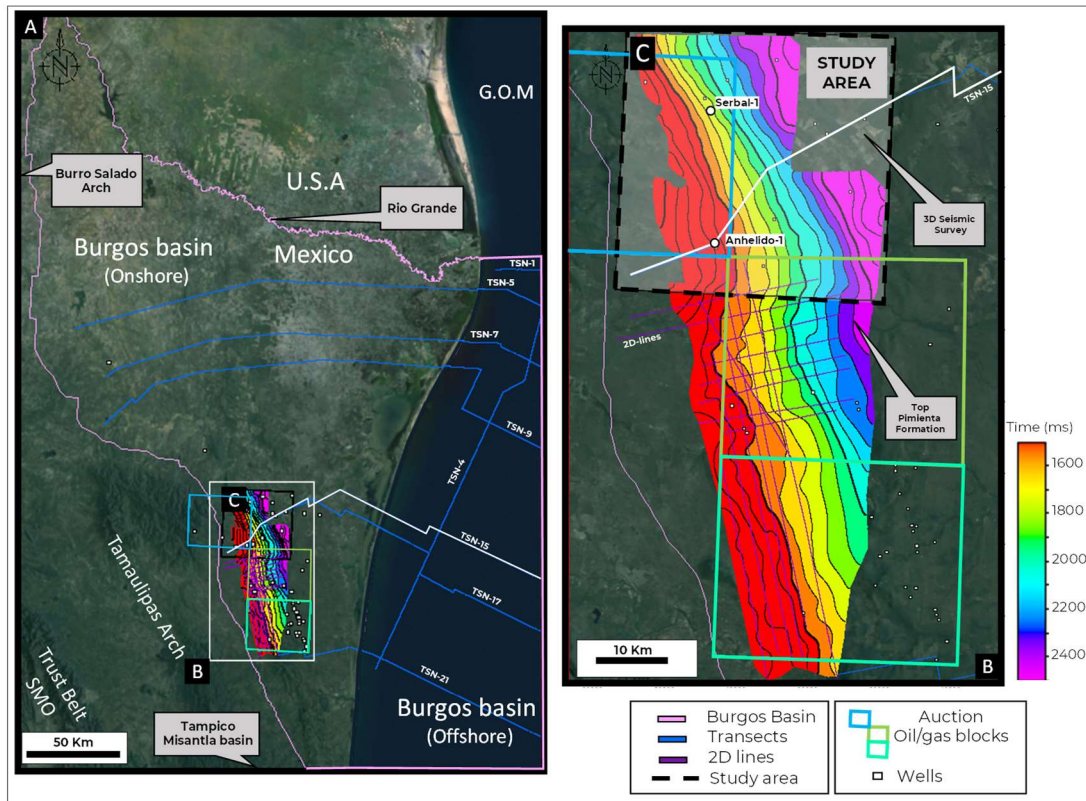


Figure 2.1 (A) Location map of the study area in the northeast of Mexico within Burgos Basin; blue lines: 2D seismic transect lines, white line: 2D transect TSN-15 showing Anhelido-1 well; (B) Study area within the black square (3D seismic data); (C) Close up of the entire area including the auction blocks, wells and the top of Pimienta formation in time domain (TWT).

2.2. Tectonic setting/evolution

The main structural context for the study area can be seen from a regional seismic transect data provided by PEMEX E&P (Figure 2.2). This has been interpreted to show the main geological features and structural styles. The regional geological context for the study area is on a gentle, seaward dipping ramp at Mesozoic levels, beneath a zone of down to basin growth faulting detaching above the main shale gas plays. This is a classic passive margin geometry, with a seaward expanding sediment wedge prograding offshore, and creating the conditions for gravity-driven tectonics. The latest thick-skinned tectonic episodes in the Burgos Basin are associated with compressional deformation that extended from the Sierra Madre Oriental and Coahuila fold and thrust belts approximately 100 km east into the Basin, interacting with the passive margin of the western Gulf of Mexico.

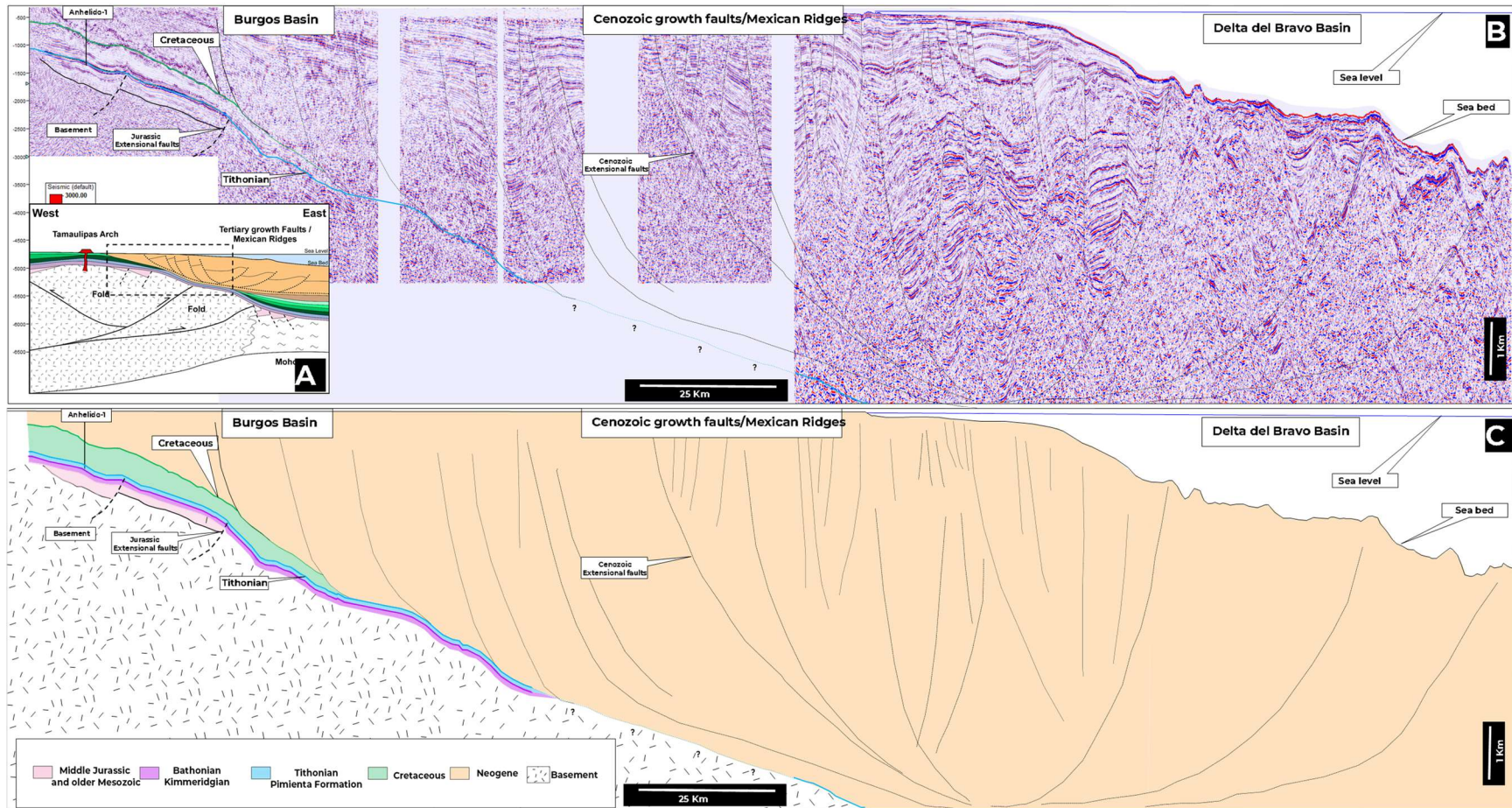


Figure 2.2 (A) Main tectonic features of study area (modified from Hurbury et al., 2003); (B) Representative regional seismic line from 3D survey and TST-15 transect passing (see figure 2.1) across the study area (onshore) toward Gulf of Mexico (offshore) showing the main geological features from the Cenozoic sediments to the basement in vertical traveltime (TWT). From West to East, the Cretaceous thins towards the Gulf of Mexico, where it is out beneath the detached growth fault system within the eastward thickening within the thick Cenozoic depocentre at the eastern of this seismic line.

Three different regions are distinguished near to the study area:

- 1) Western region that includes the fold and thrust belt of the Sierra Madre Oriental Province.
- 2) Central region characterized by open folds intruded by Cenozoic plutons in the Picachos, San Carlos and Tamaulipas Ranges.
- 3) Eastern region with an east-dipping Mesozoic homocline, overlain by Cenozoic growth faults that extend into the offshore (Perez, 1993) (Figure 2.2).

The Burgos Basin in Mexico has been the site of interaction of the Cordilleran thrust and fold belt of western North America with the passive margin of the Gulf of Mexico.

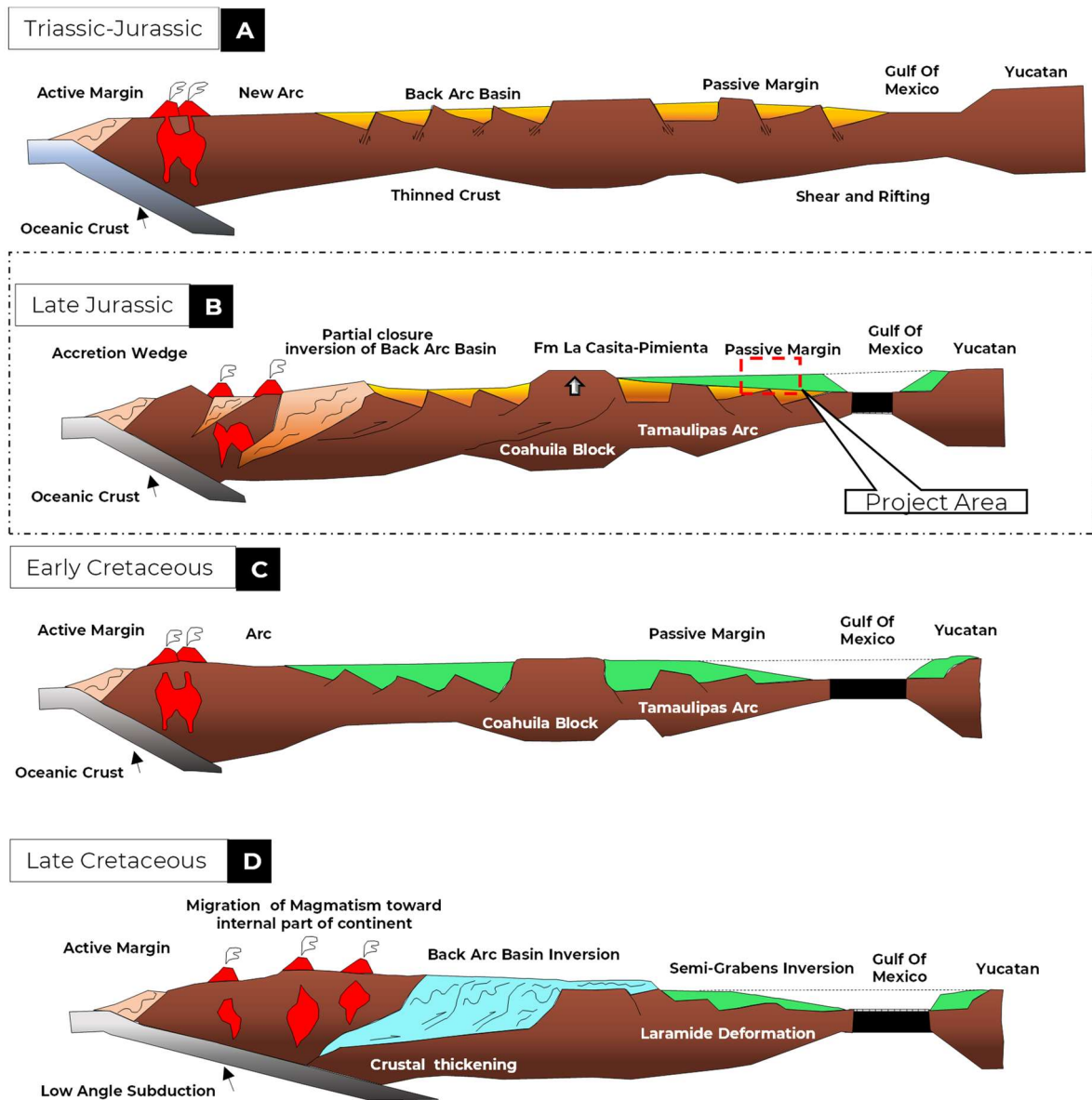


Figure 2.3 Regional tectonic evolution showing the mechanisms which interacted in the region presented in this research work; A) Triassic-Jurassic tectonic model; B) Late Jurassic Model; C) Early Cretaceous; D) Late cretaceous (modified from De Goldhammer, 1999).

The tectonic episodes in this basin include:

- 1) Middle-Upper Eocene compression which is associated with foreland deformation of the Sierra Madre Oriental and Coahuila fold and thrust belts.
- 2) Upper Oligocene regional uplift and the emplacement of granodioritic plutons.
- 3) Miocene-Pleistocene regional uplift and volcanism.

Deformation from the Sierra Madre Oriental and Coahuila fold and thrust belts was associated with compressional tectonics and the effects of this deformation can be observed as far as 100 km east into the Burgos Basin, even as far as the passive margin of the Gulf of Mexico (Figure 2.3).

The Eocene compressional regime led to the development of:

- 1) Large-scale thrusts and folds involving basement at the southwestern margin of the
- 2) Partially-inverted structures (Figure 2.4)
- 3) Tight folds with multiple detachment levels

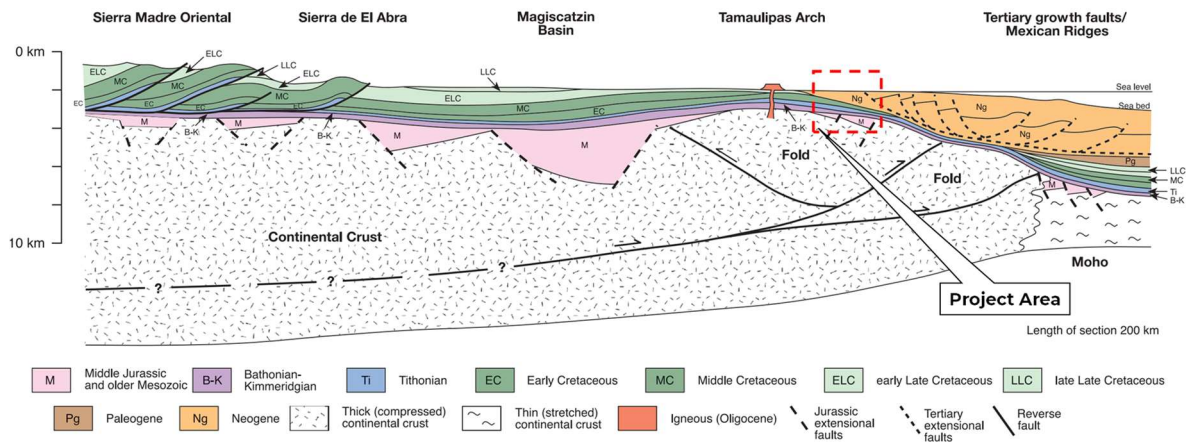


Figure 2.4 West-east cross section through the southern of Burgos Basin area, showing the geometry of the inner, Sierra Madre Oriental deformation and the presence of a second, outer zone of deformation expressed as monoclinical folding at the edge of thick continental crust. The outer zone controls many of the sequence boundaries (modified from Horbury et.al., 2003).

Regional erosion and uplift continued to the west in the Miocene to Pleistocene, producing increasing amounts of siliciclastic influx into the basin (Winker, 1982; Galloway, 1989). Sediments were accommodated within the downthrown blocks of expanded growth fault systems.

The Cenozoic normal fault trends of coastal Texas extend southward into the Burgos Basin, but their amount of expansion and orientation has been modified by periods of thrusting, folding, regional uplift, and plutonism.

At the end of the Cretaceous and beginning of the Cenozoic, the Mexican orogeny in northeast Mexico reached its maximum development, resulting in uplift, thrusting, and formation of the Sierra Madre Oriental, as well as in the partial reemergence of the Burro-Picachos Peninsula and San Carlos Island (Alfonso, 1976, Gonzalez, 1976; Rivera, 1976).

The postulated cause of this pulse of orogenic activity was the arrival of buoyant oceanic lithosphere at the western North America subduction zone (Pindell, 1985).

Jurassic sedimentation in northeast Mexico was notably influenced by three paleogeographic elements: the Coahuila Peninsula, the El Burro-Picachos Peninsula and the San Carlos Island (Gonzalez, 1976)

The Burgos Basin is characterized by an extensional normal fault system within the Neogene detaching in the Upper Cretaceous. Beneath this classical gravity driven tectonic system, the Pimienta Formation within the upper Jurassic sequence is recognisable on seismic profiles displays a negative amplitude response due to its position underlying a high velocity carbonate. This has an interval velocity of c. 5700 m/s derived from sonic logs, whereas the underlying Pimienta Formation has a much lower velocity of 4700 m/s in the study area (Figure 2.5).

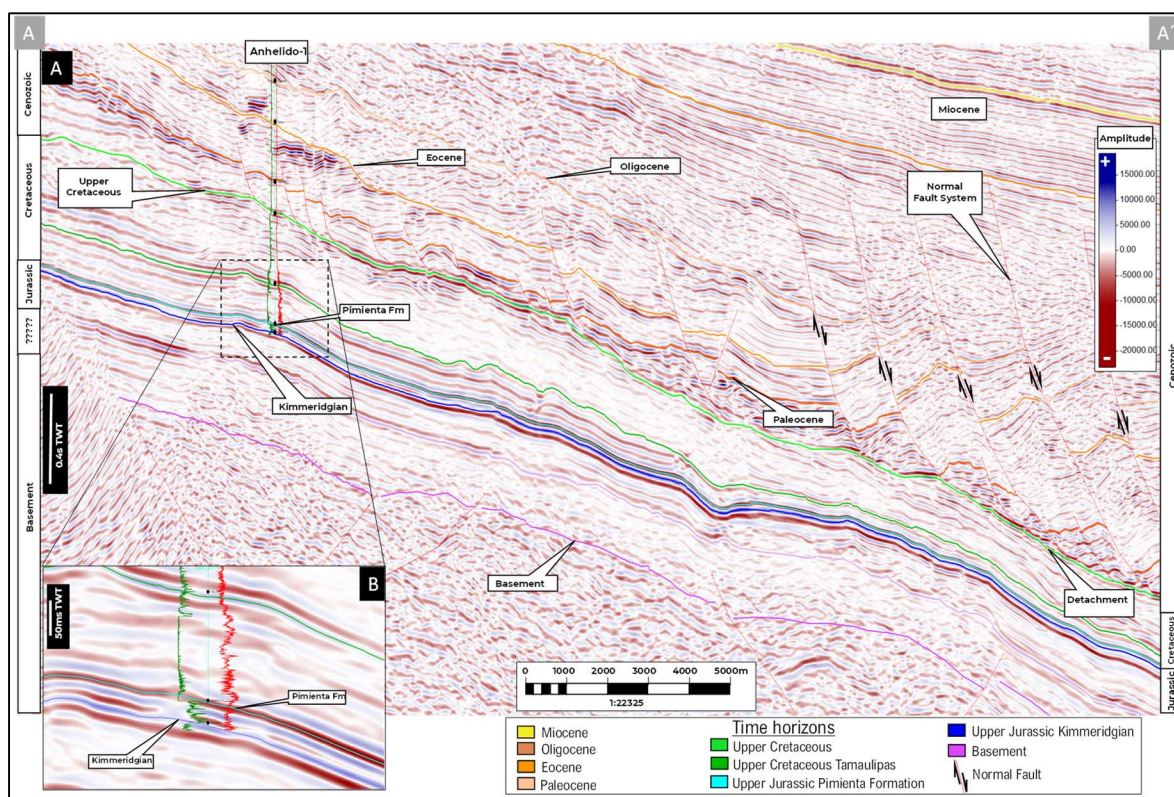


Figure 2.5 (A) Representative seismic line from 3D seismic survey passing across the study area showing the interpretation and the main geological features from the Cenozoic sediments to the basement in vertical travelttime (TWT). A-A' profile is displayed in an E-W direction, and shows seaward thinning of the Cretaceous megasequence, and the detachment of the growth fault system below the Eocene and Paleocene at the eastern end of the seismic line; (B) Close-up of the tilted top of the Upper Jurassic (Tamaulipas Formation) and Upper Jurassic (Pimienta Formation) which shows a negative amplitude response associated with the abrupt velocity change at this boundary.

2.3. Stratigraphy

The Pimienta Formation is an organic-rich mudrock in the Burgos -Tampico Misantla Basin. According to PEMEX E&P, this formation is considered as the main source rock for oil and gas. This important Upper Jurassic source rock is of variable thickness, reaching over 200 meters (Figure 2.6). It consists of marine black shale and shaly limestone containing Type II/III kerogen, divided into three intervals with varying concentration of carbonate components and TOC richness. TOC values range up to 6.5%. Tmax values obtained from pyrolysis of 450-454°C indicates condensate to wet thermal gas according to the PEMEX database of (confidential reports). XRD analyses of samples

from wells drilled in the project area shows that the Pimienta Formation source intervals have a favorably brittle mineralogical composition with average compositions being 39% calcite, 40% quartz, and 13% clay for Anhelido-1 and in Serbal-1 the values are 35% calcite, 1% dolomite, 35% quartz and 10% illite (Table 2.1).

Anhelido-1	Depth (m)	Quartz	Feldspar	Plagioclase	Calcite	Dolomite	Pyrite	Marcasite	Total Clay
	2104.37	0.489	0.004	0.014	0.318	0.011	0.03	0	0.135
	2113.33	0.057	0	0	0.886	0	0.008	0	0.049
	2115.23	0.45	0.003	0.023	0.228	0.032	0.05	0.02	0.194
	2119.35	0.635	0.004	0.02	0.141	0.003	0.03	0.009	0.159
Serbal-1	Depth (m)	Quartz	Feldspar	Plagioclase	Calcite	Dolomite	Pyrite	Marcasite	Total Clay
	2901.9	0.45	0.02	0.04	0.25	0.02	0.03	0.01	0.18
	2903.48	0.3	0.02	0.02	0.49	0.01	0.02	0.01	0.13
	2904.45	0.33	0.02	0.03	0.4	0.01	0.03	0.01	0.16
	2906.12	0.36	0.03	0.05	0.19	0	0.03	0.01	0.32
	2908.77	0.37	0.02	0.06	0.27	0.02	0.05	0	0.21
	2910.85	0.27	0.02	0.04	0.33	0	0.04	0.01	0.28
	2911.35	0.42	0.02	0.04	0.21	0.001	0.04	0.01	0.23
	2912.09	0.41	0.02	0.05	0.2	0	0.05	0.01	0.24
	2913.65	0.33	0.03	0.05	0.21	0	0.05	0.01	0.31
	2914.27	0.33	0.02	0.03	0.29	0	0.03	0.01	0.27
	2916.91	0.03	0.02	0.03	0.75	0	0.02	0	0.14
	2917.4	0.57	0.03	0.04	0.13	0	0.04	0.01	0.18

Table 2.1. XRD data table for the project in two wells Anhelido-1 and Serbal-1 respectively.

This dominant lithofacies is a clay rich black mudstone, slightly pyritized, with thin stratification and intercalations of laminar black shale, bentonite and flint lenses. Perez (2014) notes that within the Burgos Basin, the rocks of the Pimienta Formation are homogeneous and constituted by calcareous-carbonaceous shales. However, within their megascopic description, Perez (2014) noted that there are alternations of these shales with light grey limestones, black clayey limestones, and black shales.

The Pimienta Formation of the Burgos Basin is equivalent to the La Casita Formation of Tampico-Misantla Basin (Figure 2.6). The Eagle Ford Formation of South Texas is partly equivalent to the Agua Nueva Formation of northeast Mexico (Peterson, 1985). The relation between both formations is that they have similar facies of limestone with dominant calcareous-carbonaceous shales.

Both these prolific source rock intervals are derived from an anoxic low energy deep water environment, with sedimentation regulated by a transgressive event and a continuous supply of organic matter (Dawson, 2000).

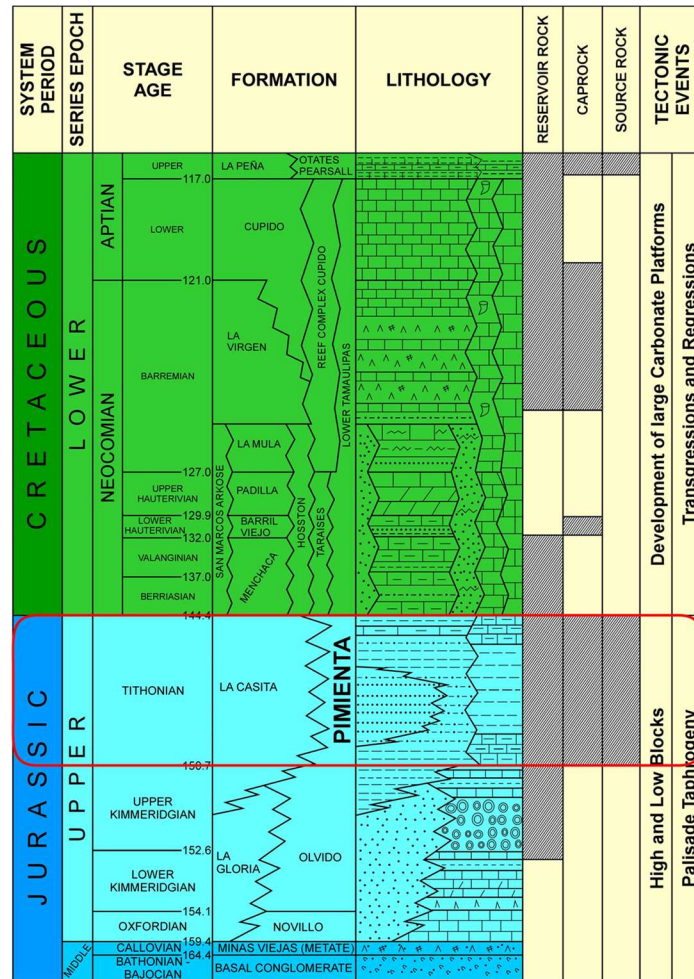


Figure 2.6. Geological column of study area focuses on Upper Jurassic Pimienta Formation (red polygon)

The Pimienta Formation is a predominantly clayey unit overlying limestones from the Olvido Formation and underlying the Taraises Formation in the north and the Lower Tamaulipas Formation in the central and southern portions of the basin. It is subdivided into 3 informal lithostratigraphic units, based primarily on log response (Figure 2.7). These subdivisions exhibit different degrees of lithological variations depending on their distribution within the Burgos Basin (Fernández et al., 2012)

The lower unit was defined as a serrated grain-increasing electrical log response distinguishing itself from the Olvido Formation that underlies this unit. The mid unit is characterized by presenting a

serrated linear electrical log response in most of the observed logs and finally the upper unit shows a response in a general upward coarsening log motif superimposed on a serrated pattern with a transitional upper contact towards the lower Tamaulipas Formation in the Cretaceous.

The subdivision criterion within the Pimienta Formation was defined informally by PEMEX in 2012 and is lithostratigraphic, based on log response rather than biostratigraphic dating (chronostratigraphy).

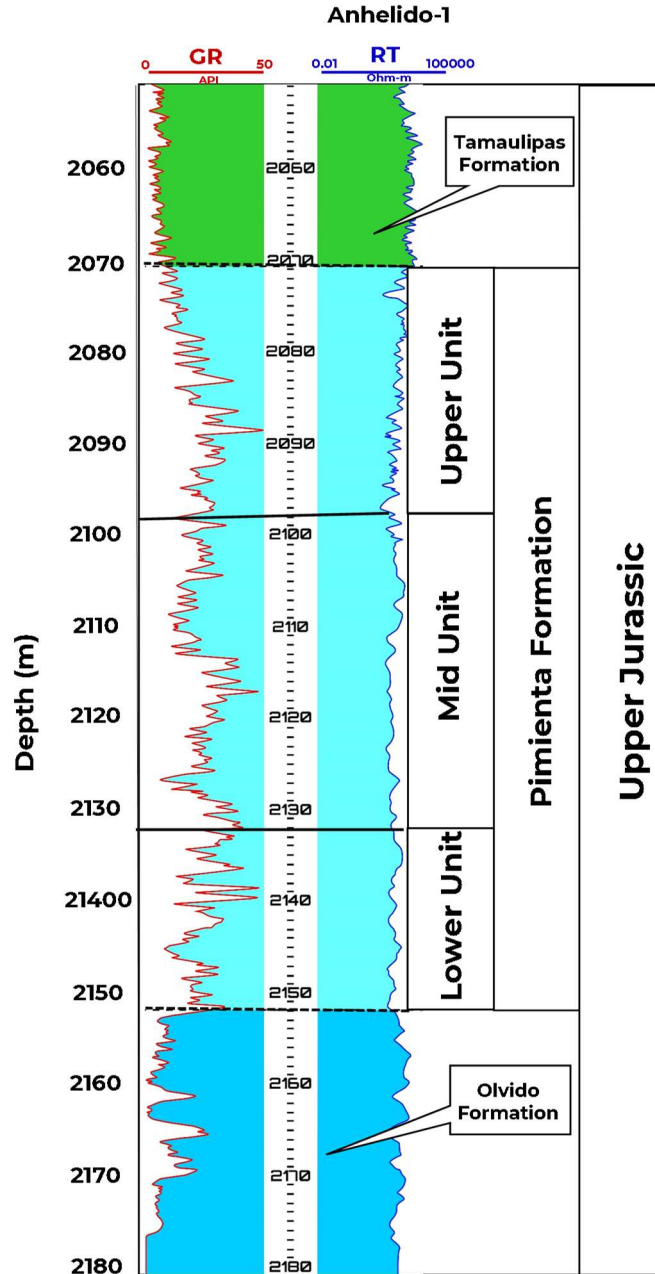


Figure 2.7 Subdivision into three stratigraphic units of the Pimienta Formation in the southern portion of the Burgos Basin, Gamma Ray (GR) in red curve and Resistivity log in blue (modified from PEMEX E&P, 2012).

The Pimienta Formation exhibits variable thicknesses throughout the Burgos Basin. The log correlation with datum at the top of Tithonian subdivided by the 3 different stratigraphic units where it is possible observe considerable variations in thickness variations of 50 to 210 m depending on the position within the basin (Figure 2.8)

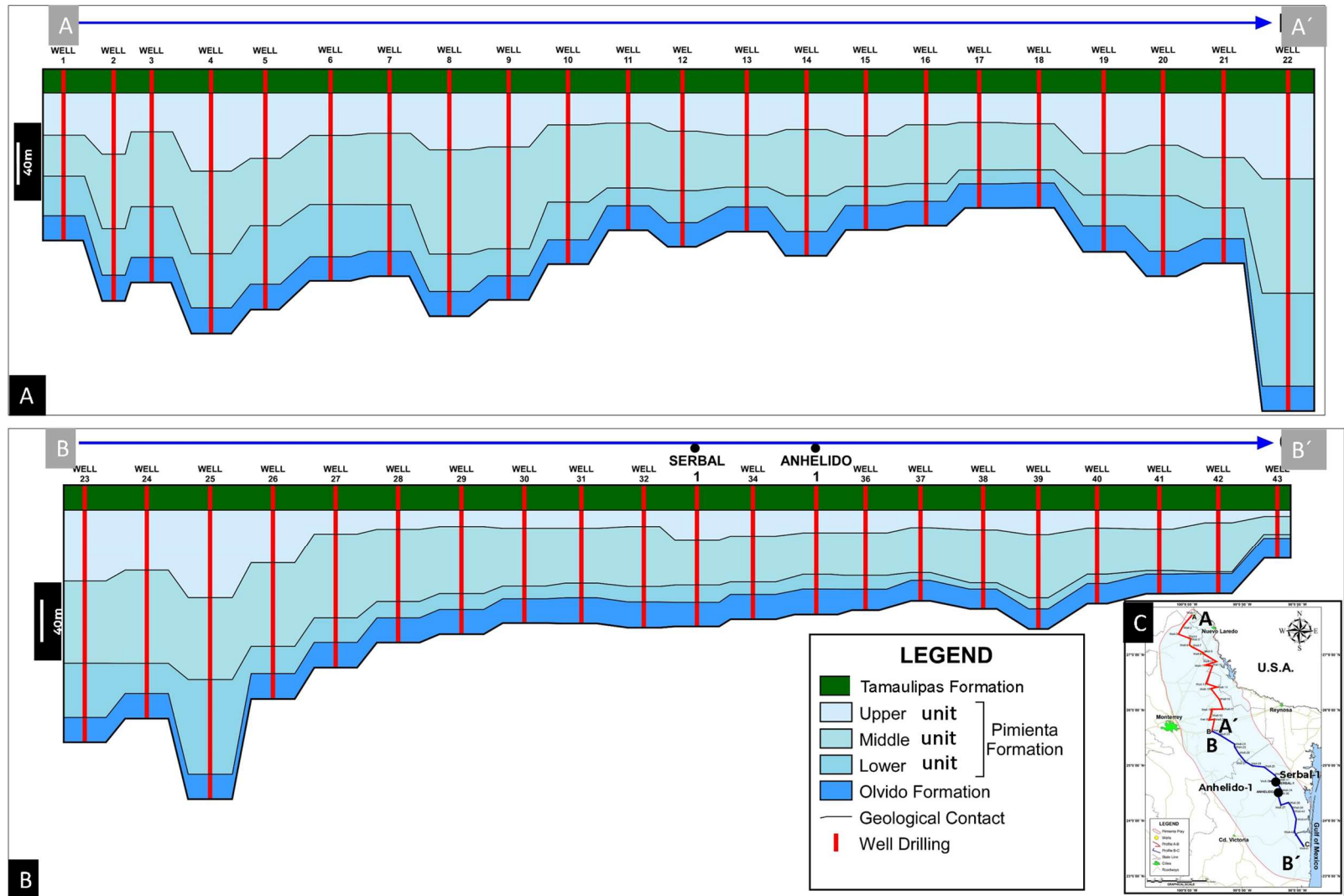


Figure 2.8 (A) (A-A') first part of Stratigraphic regional of Pimienta formation; (B) (B-C) second part of regional line including Serbal-1 and Anhelido-1; (C) Both lines (A-B red) and (B-B' blue) cover the entire Burgos Basin from north to south with thickness variations (modified from PEMEX, 2012).

The control on the variation in thickness is due in large part to the configuration of the pre-existing basin. During the early opening of the Gulf of Mexico, the extensional stress regime led to the development of a number of half graben mini-depocenters were initially filled by continental sediments. Later deposition transitioned to fully marine sediments as the oceanic waters invaded the area (Buffler and Sawyer, 1985; Salvador, 1987; Goldhammer and Johnson, 2001).

The entire sedimentary column overlies an igneous-metamorphic basement (that was consolidated and deformed in the Permo-Triassic, and which was immediately overlain by continental red beds derived from the erosion of the paleo-relief, as well as by volcanic rocks produced during the rifting process (Figure 2.2).

During the Late Kimmeridgian-Tithonian a slow subsidence generated in the northeast of Mexico led to the deposit of transgressive clay rich sediments with a terrigenous influence. These sediments fill the depressions of the Sabina's Basin (La Casita Formation), while at the same time and laterally there was a facies change towards the Burgos Basin to more open marine deposits (Figure 2.9), constituted by black shales and dark gray carbonaceous, organic rich shales with intercalations of clayey limestones corresponding to the Pimienta Formation. These mark the beginning of a global marine transgression, which mostly flooded the platforms previous carbonates found in Jurassic Paleogeography (Padilla y Sánchez, 2016).

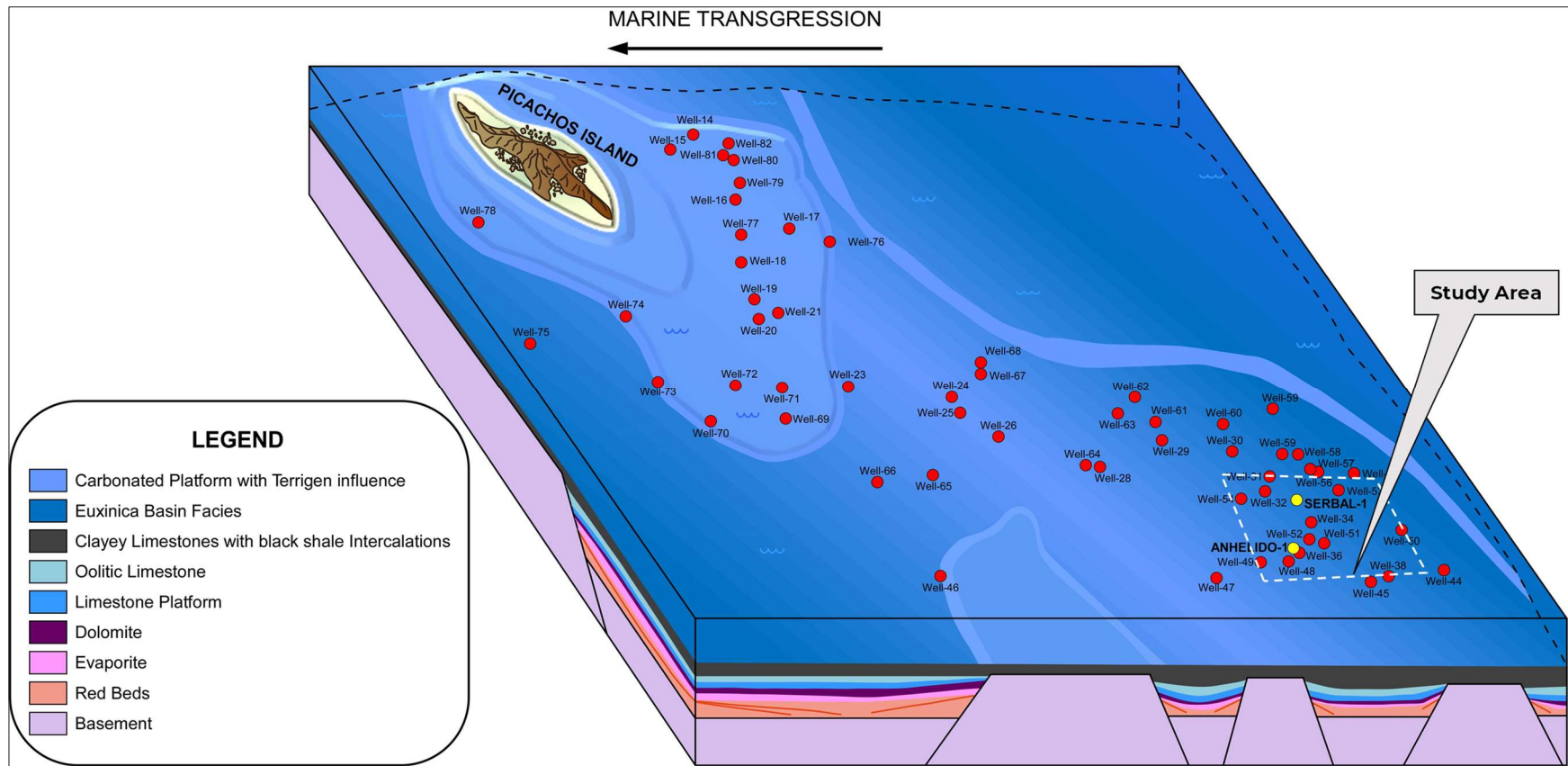


Figure 2.9 Depositional model of Late Kimmeridgian-Tithonian showing the Jurassic paleogeography of the Pimienta Formation according with core and log data (modified from PEMEX 2012).

2.4. Geochemistry of the Pimienta Formation

The Tithonian rocks in Mexico have geochemical properties that establish them as the most significant source rock of the country, and it is for this reason that many authors, for several years, have characterized the organic matter intrinsic in these rocks from a variety of locations. Some of the key results obtained from these investigations are summarized as follows:

Gonzales and Holguín (1992) established that the marls and shales of this formation contain Kerogen type II, which has a Rock-Eval S2 value of more than 2.5 mgHC /g in 45% of the 120 samples analyzed. Also, these geochemical analyses indicate that in limestone and limestone shales of the Upper Jurassic (Pimienta Formation), the TOC values are above 3%, while some samples, despite their maturity, can generate more than 5 mg of hydrocarbons per gram of rock.

Bernal-Vargas et al. (1998) state that the Pimienta Formation in the Tampico Misantla Basin has an organic content ranging from 0.4 to 6.5%, a Hydrogen Index (HI) from 18 to 959 mg HC/gTOC, a T-max of between 412 ° and 476 ° C.

The composition and main organic geochemical and reservoir parameters of some of the major North American unconventional shale reservoirs is shown in Table 2.2 for comparison with the equivalent parameters for the Pimienta Formation compiled from Sone and Zoback (2013). The Pimienta Formation exhibits similar characteristics in composition and reservoir parameters to the Haynesville-2 sample group (Table 2.2). However, in terms of elastic (P-Impedance vs. S-Impedance) behavior, the Pimienta Formation has generally higher values due to the mineral composition (derived from XRD data). In Chapter 5 these elastic parameters will be addressed and shown in a crossplot of P-Impedance vs. S-Impedance calculated from well log data and mineral composition.

Sample Group	In situ Stress (MPa)	Maturity (Ro/Tmax) (%/C)	Dry Bulk Density	QFP(vol. %)	Ca (vol.%)	Clay(vol. %)	Kerogen (vol.%)	Estimated porosity(%)	Description	Clay Preferred orientation	Shape of Organics
Barnett-1	Sv. 65	Mature (oil to wet gas)	2.39-2.47	50.52	0-3	36-39	9-11	4-9	Silt grains in clayey matrix	Yes	Patches to Lenses
	Pp. 30	Tmax=445-465									
	σeff. 35	Ro=0.85-0.91									
Barnett-2			2.63-2.67	31-53	37-60	3-7	2-3	1-2	Carbonate rock	No	Very Few patches
Haynesville-1	Sv. 85		2.49-2.51	32-35	20-22	36-39	8	6	Silt grains in clayey matrix	Yes	Lenses
	Pp. 60-70	Overmature (dry gas)									
	σeff. 15-25	Tmax=525-545									
Haynesville-2			2.60-2.62	23-24	49-53	20-22	4	3-4	Silt grains in clayey /calcareous matrix	No	Lenses to layers
Eagle Ford-1	Sv. 90	Mature (wet gas)	2.43-2.46	22-29	46-54	12-21	9-11	5-7	Calcareous biotigrains in clayey/calcareous matrix	No	Lenses to layers
	Pp. 65	Tmax=478-481									
	σeff. 25	Ro=1.29-1.39									
Eagle Ford-2			2.46-2.54	11-18	63-78	6-14	4-5	5-7	Calcareous biotigrains in clayey/calcareous matrix	No	Lenses to layers
Fort St. John	Sv. 25-30	Mature (oil to wet gas)	2.57-2.60	54-60	3-5	32-39	4-5	5-6	Silt grains in clayey matrix	Yes	Patches
	Pp. 10-12	Tmax=450-460									
Pimienta	Sv. 54	Mature (oil to wet gas)	2.33-2.68	42	40	13	15	8-10	Silt grains in clayey matrix	Yes	Lenses
	Pp. 24	Tmax=439-450									
	σeff. 30	Ro=0.81-0.92									

Table 2.2. Summary of reservoir conditions, mineral composition, and microstructural observations of gas shale samples including Pimienta Formation (modified from Zoback, 2009).

2.5. Exploration History

Mexico has the sixth largest reserve of shale gas in the world, with an estimated 665 trillion cubic feet (U.S. Energy Information Administration, 2013). Despite low permeability and high production decline rates typical for these type of rocks, there is evidently considerable potential for shale gas exploitation and much of the interest centres on the Pimienta Formation because of its analogous characteristics to the proven Haynesville shale play.

Mexico's national oil company PEMEX has drilled more than 12 shale gas/oil exploration wells with modest results budgeting 575 million USD in 2014.

Many of Mexico's shale basins are too deeply buried in their axes for shale gas and shale oil development (>5 km), while their western portions tend to be overthrust and structurally complex because of their proximity to the contractional tectonic domains along the western margins of the country. However, the less deformed eastern portions of these basins and adjacent shallower

platforms are structurally more simple. Here, the most prospective areas for shale gas and shale oil development are buried at suitable depths of 1 km to 5 km over large areas.

PEMEX made its first shale discovery in the Burgos Basin during late 2010 and early 2011, drilling the Emergente-1 shale gas well located a few kilometres south at the Texas/Coahuila border on a continuation of the Eagle Ford Shale trend from Texas.

In November 2012, PEMEX drilled four shale gas exploration wells in the Eagle Ford play of the Burgos Basin with one shale exploration well in the Sabinas basin, reporting initial production for three wells. These wells include Nómada-1 located in the oil window, Habano-1, Montañés-1 well in the wet gas window of the Burgos Basin (Figure 2.10). The dry gas window in the Burgos Basin was tested by the Emergente-1 well.

The Percutor-1 tested the dry gas window in the Sabinas Basin. Also, PEMEX drilled and produced gas from the Arbolero-1 well, the first test of the Jurassic shale in this basin.

In 2012 PEMEX also drilled Anhelido-1 and Serbal-1 within Upper Jurassic Pimienta Formation. Anhelido-1 was the first well in unconventional resources to discover light oil with 38 API. Anhelido-1H (horizontal side wellbore) was landed just above the peak radioactivity zone according to the well log data, where clay content was lower, TOC higher, and the formation considered more brittle.

In contrast, Serbal-1 found traces of condensate but without being economically profitable. Both pilot wells were drilled horizontally within the Pimienta Formation with 17 hydraulic fracturing stages each with an average drilling of approximately 1500m horizontally. These two wells are the most valuable calibration dataset used in this project. The initial reserves incorporated of Anhelido-1 0.7 MMBOE in proved reserve (1P), 3.2 MMBOE probable reserve (2P), and 8.2 MMBOE in possible reserve (3P).

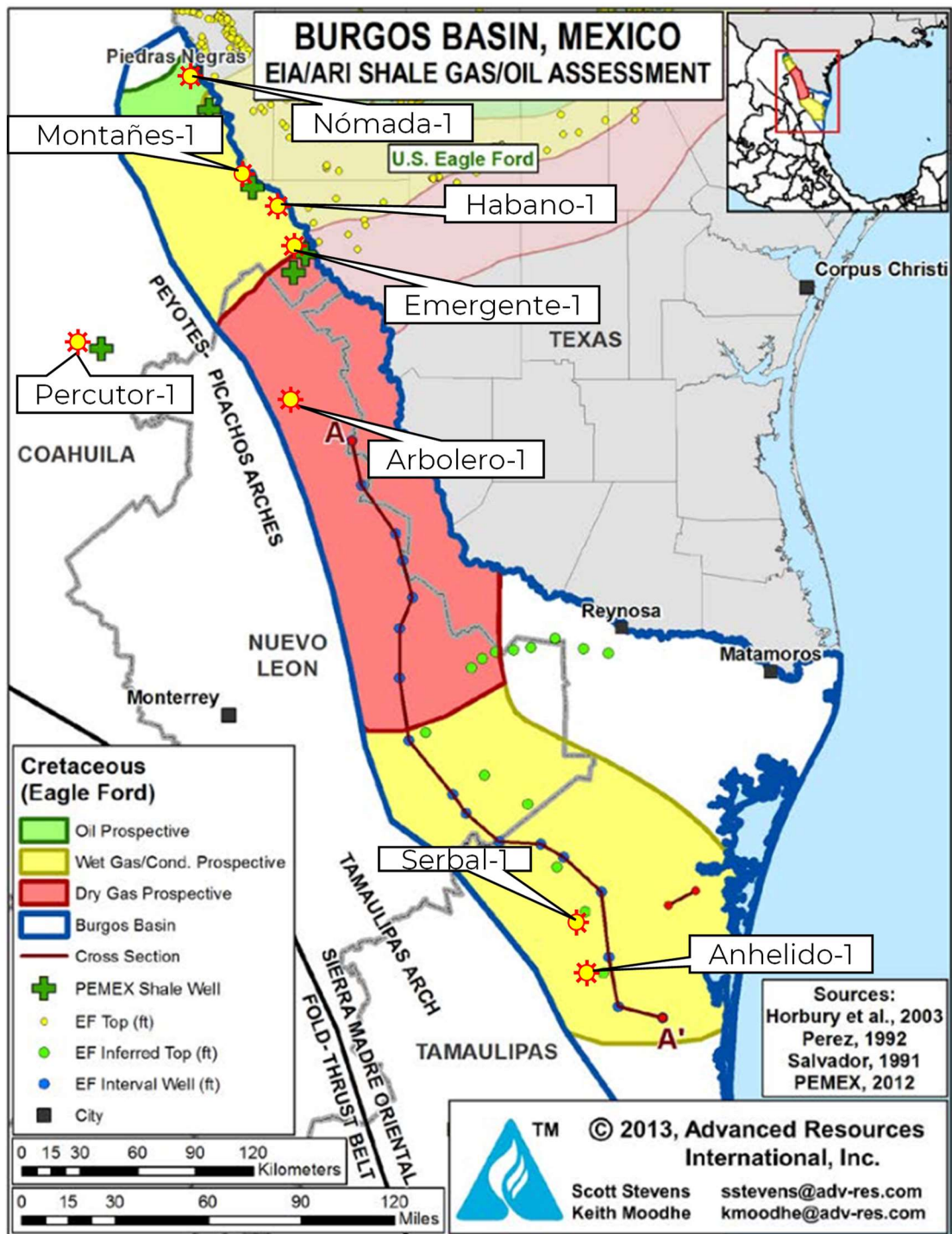


Figure 2.10 Burgos Basin outline and shale gas and shale oil prospective areas (modified from Horbury et. al., 2003; Perez, 1992; Salvador, 1991; PEMEX, 2013).

2.6. Petroleum system

The oil provinces in the Tampico-Misantla Basin and the southern part of Burgos Basin are mainly producing oil. For production of this oil, the most important fields are those of the Upper Jurassic and Middle Cretaceous in the northern with almost 50% of the 6.5 BBOE accumulated in its reserves (Figure 2.11). It is worth mentioning that the Middle Cretaceous still holds 5% of the hydrocarbon reserves in the province; but this figure excludes consideration of the remaining oil not recovered by traditional exploitation methods as of January 1, 2013. Prospective resources evaluated in the area have an average of 2.5 BBOE (PEMEX, 2013).

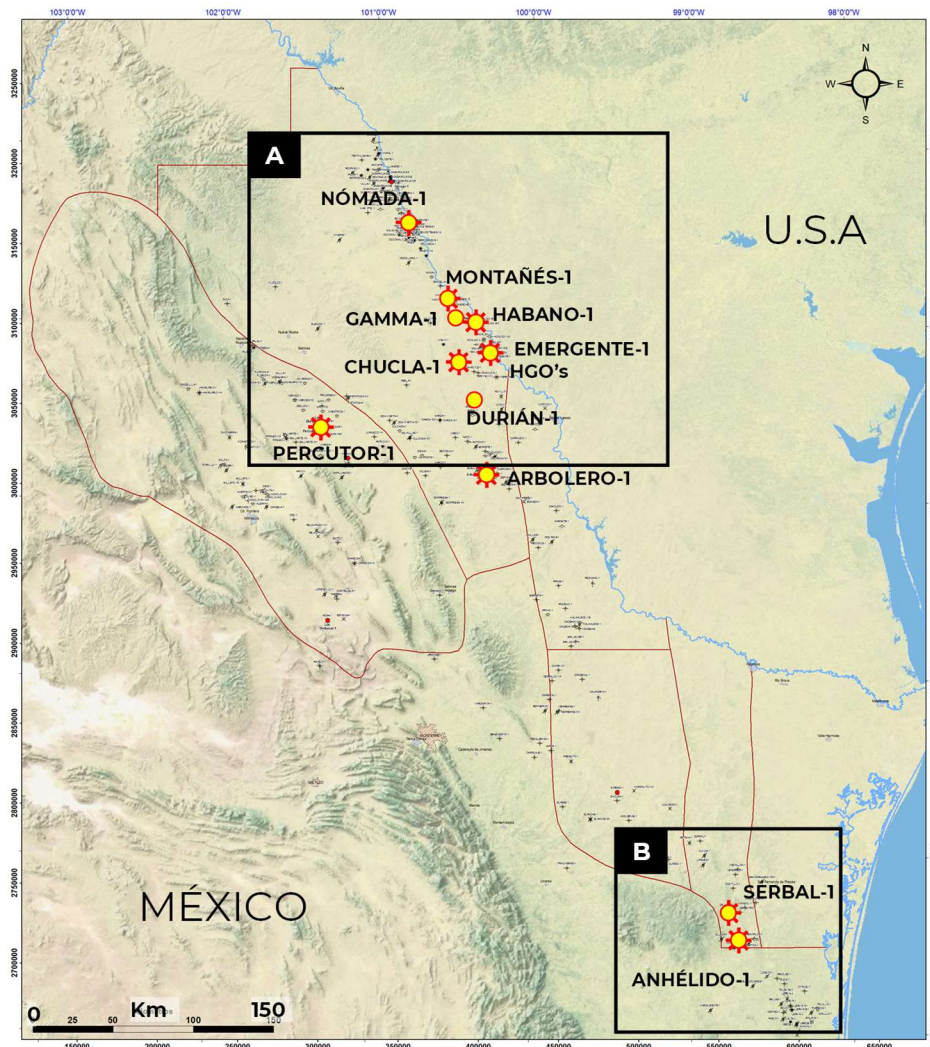


Figure 2.11 A) Important field in Mid Cretaceous within Eagle Ford Formation; B) Upper Jurassic field within the study area.

The Pimienta Formation in the onshore part of the basin passed through the critical moment of generation-expulsion of hydrocarbons at the end of the Oligocene (23.8 myr), as shown in (Figure 2.12) (PEMEX E&P, 2010).

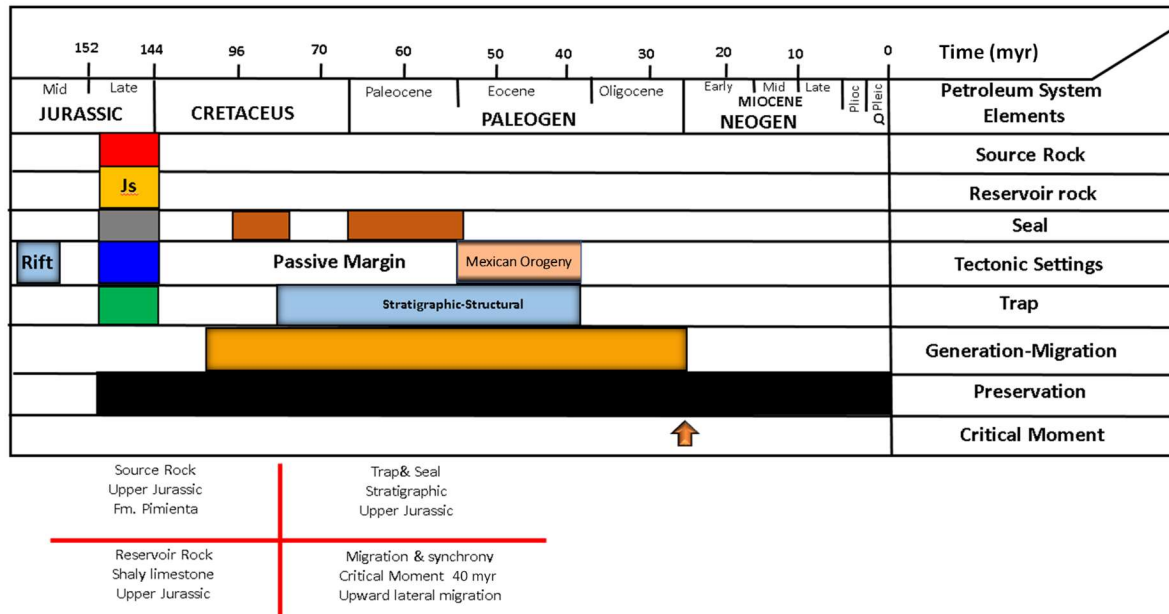


Figure 2.12 Elements and Events of the Tithonian-Kimmeridgian-Cretaceous Oil system in the Burgos-Tampico Misantla Oil Province (modified from PEMEX E&P, 2010).

3. Data, methods, and dataset preparation

3.1. Introduction

The geophysical information used in this project primarily includes 3D seismic data provided by PEMEX E&P Oil company along with wireline logs for vertical and horizontal wells, core information and other specific information like XRD and geochemistry data, e.g., total organic carbon. In addition, there are specific azimuthal seismic data for this project with particular application to fracture detection and characterization. In seismic interpretation, well data and seismic need to be calibrated to match geological markers with seismic to the correct correlation between the wells within the project area in order to build the geological framework. 2D regional arbitrary seismic lines (TSN-15) were also provided to understand the regional geological context of the Burgos Basin. The data list used in this thesis work is listed in (Table 3.1).

Seismic data	Description
3D azimuthal gathers	Common mid-point (CMP) azimuthal data in Prestack time migration
3D Prestack time migration	3D Seismic data set (Kirchhoff algorithm)
3D Velocity field (RMS)	RMS velocity field of seismic data
2D seismic data	Regional Transects
Well log data	
Sonic (P-wave) (us/ft) Sonic (S-wave) (us/ft) Density (Rhob) (gr/cc) Resistivity (RT) (ohm-m) Gamma Ray (GR) (API) Caliper (inch) Markers	
Reservoir data	Description
34 Minifrac test	Instantaneous Shut in Pressure
Build-up test	Skin and permeability of reservoir

Table 3.1. List of Data set used in the project area

For seismic interpretation purposes, I used the pre-stack time migration version of the Anhelido 3D seismic survey. This was acquired on land using vibroseis sources and followed a processing sequence that was specifically designed to improve the signal-to-noise ratio (Figure 3.1). The 3D seismic acquisition parameters and configuration were designed with a special focus on the Tithonian shale Jurassic rocks as a target. The total area of acquired data is roughly 1900 km².

The Anhelido 3D survey was acquired in 2014 by PEMEX national oil company with the follow parameters in Table 3.2:

Acquisition parameters			Source		Receivers	
182 channels	Initial Frequency	8 Hz	Vibroseis	4	Type	SM-24
Source interval	Final Frequency	96 Hz	Sweep	6	quantity	6
Receiver interval	Sweep Type	Linear	Weight	60000 lbs	Record interval	5 seg
Receiver interval 50m	Sweep length	20 s	Record interval	5	bin	25
LR 350m	Initial Taper	460 ms	Source area	731 Km ²	Natural frequency	10Hz
LS 350m	Final Taper	460 ms			Receivers area	1365 Km ²
Minimum Offset	451 m					
Maximum offset	6408 m					

Table 3.2. Acquisition parameters in the Anhelido 3D Seismic survey

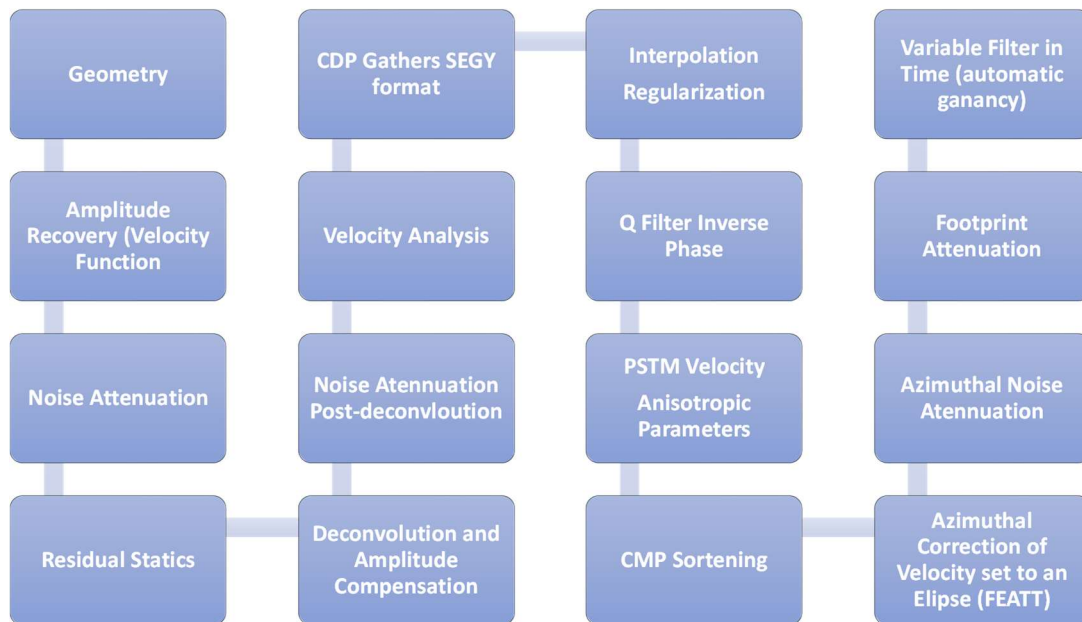


Figure 3.1. Processing sequence in Anhelido 3D seismic data survey.

3.2. Seismic data and well log interpretation

For this project, I interpreted five stratigraphic horizons within Upper Cretaceous and Upper Jurassic in the time domain (displayed with two-way travel time (TWT) on the vertical axis (Figure 3.2). These horizons were used for the seismic inversion including the analysis of amplitude variation with angle and azimuth for each well in the project area. The azimuthal seismic data allowed the quantitative characterization of those anisotropic parameters related to fracture distribution using Rüger approximation (see Chapter 5).

For the generation of synthetic seismograms of 6 wells, P-Sonic, S-Sonic-S and Density logs were used. An initial Ricker wavelet is used with the frequency associated with the window of interest. The next step was to use a time-depth curve from a Check Shot Survey to convert depth values on the log displays into time values.

Once the first data conditioning steps are completed, a wavelet is extracted from the seismic volume at the well location in phase and seismic frequency. In parallel, the amplitudes of the seismic traces near the well and the amplitudes generated by the Impedance-P of the well are correlated and verified.

The seismic-well correlation is validated with the well impedance adjustment compared to the preliminary impedance section and the wavelet is generated for the stack seismic volume.

The synthetic seismogram is generated to calibrate the well with the seismic data (White and Simm, 2003). The synthetic trace is adjusted so that the marker of interest derived from the well at a known depth position can be correlated and matched with the seismic response. Prior to the beginning of the seismic interpretation an analysis of the structural and stratigraphic framework is undertaken in order to have an idea of what the geological features will be interpreted. Subsequently, seismic sections are extracted from the 3D volume to correlate the main structural and stratigraphic characteristics of the study area (Figure 3.13).

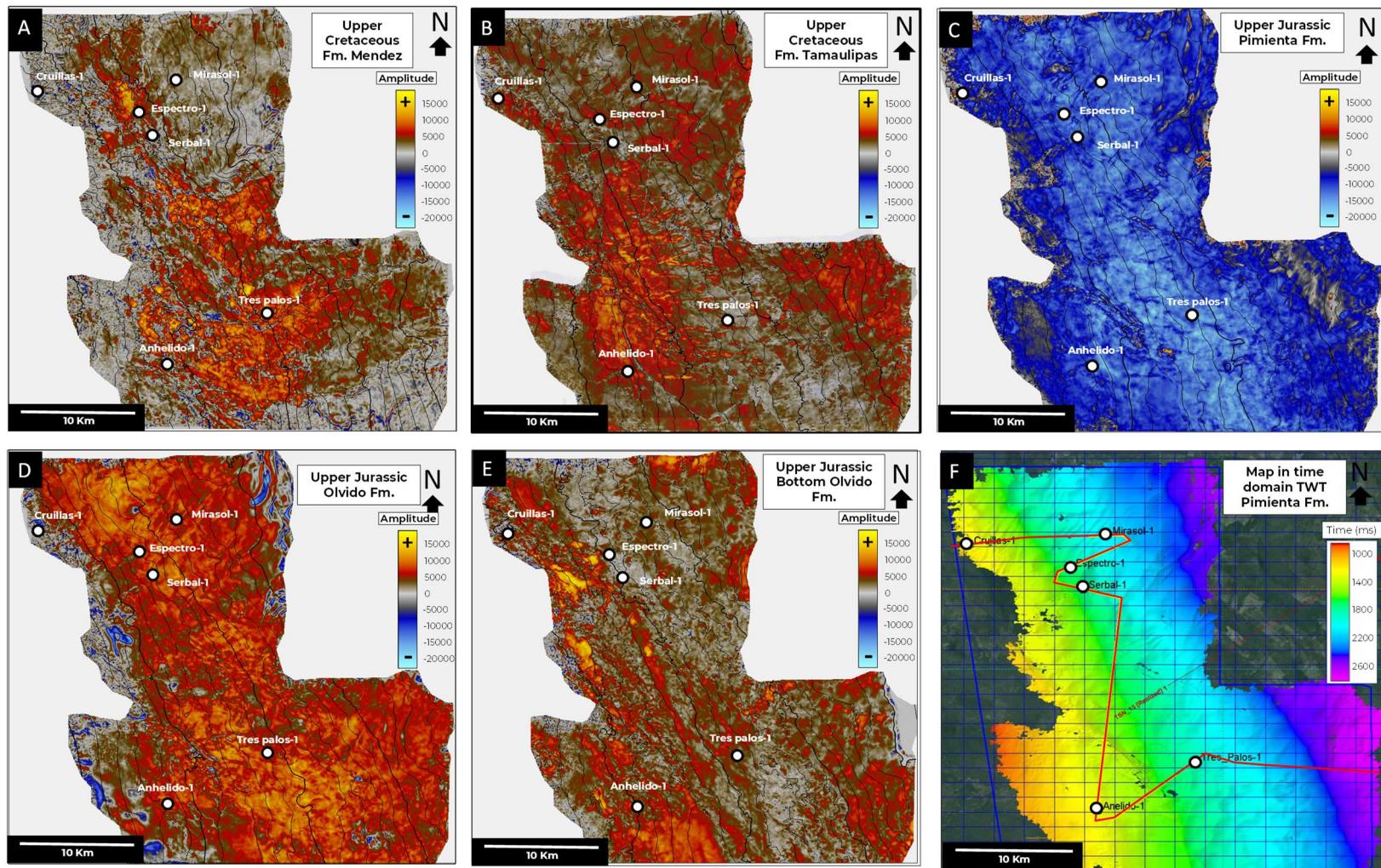


Figure 3.2 Stratigraphic interpretation in time vertical domain with exact raw amplitude extraction as quality control (TWT). A) Upper Cretaceous Mendez Formation (positive amplitude); (B) Tamaulipas Formation (positive amplitude); (C) Upper Jurassic Pimienta Formation (negative amplitude); (D) Olvido Formation (Positive amplitude) and an extra map interpretation; (E) The bottom of Olvido Formation (positive amplitude); (F) Interpretation map of Pimienta formation within Upper Jurassic Tithonian in the time domain (TWT ms).

3.2.1 Azimuthal data offset vector tile (OVT)

In the standard general methodology of seismic acquisition, it is typical to record by sampling only a single azimuth. In contrast, azimuthal seismic data have information on reflection data acquired in different azimuths. The actual offset azimuth distribution for the Anhelido 3D seismic data is shown in the rose diagram in the Figure 3.3. This gather information were processed by Dowell Inc. (Schlumberger) and delivered to PEMEX E&P with the purpose of targeting shale rock types in the Pimienta Formation for this PhD research project.

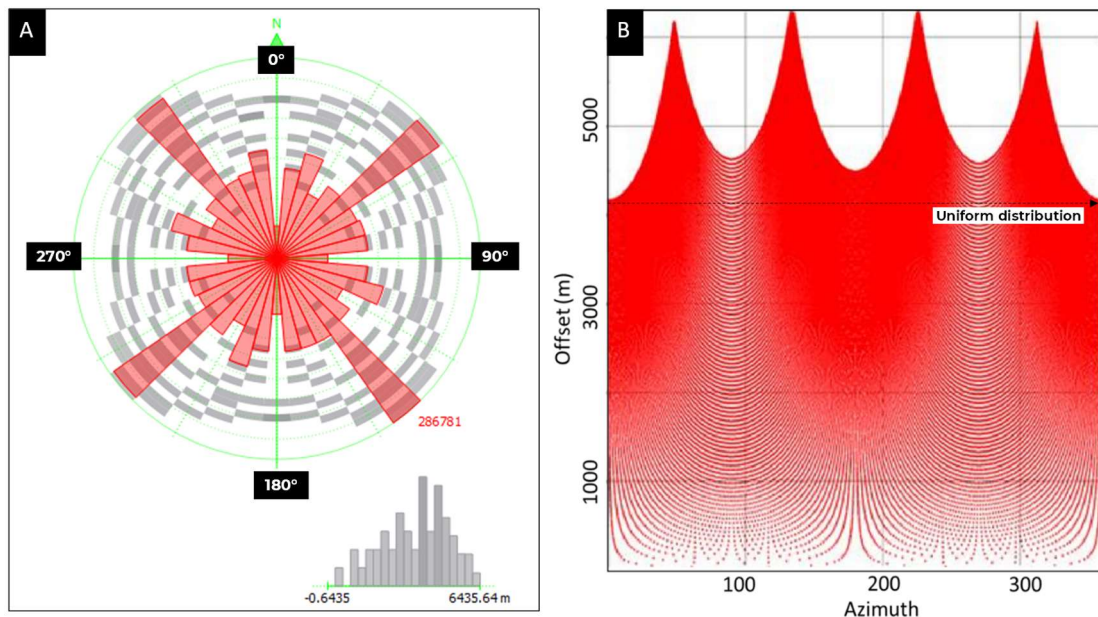


Figure 3.3 (A) Rose diagram illustration of overall survey offset-azimuth distribution of 3D survey Anhelido 3D; (B) the acquisition offset versus azimuth distribution. Note that a uniform distribution is achieved only up to approximately 4000m offset.

The seismic data is sorted in OVT (Offset Vector Tiles) consisting of a small range of inlines and crosslines (Vermeer, 2007). This is a domain where the information is classified according to offset and azimuth segments. These segments are based on the ordering by areal groups, where the traces with their midpoints are divided into mosaics with dimensions dictated by the spacing between their receiving lines and source lines from this way the nominal stack is honoured (Figure 3.4)

The data are also migrated in offset vector tiles (OVT). This is a particular prestack seismic gather type, and OVT technology is a seismic processing technology suitable for wide-azimuth seismic (WAZ) exploration which has significant advantage in many aspects. Cary (1999) introduced this technology as a basic building block of wide-azimuth surveys, and the methods are described in detail by Vermeer (2002, 2003 & 2007).

The spreading discontinuity, global noise attenuation, azimuthally sectorized interpolation, and preserved azimuthal information for fracture detection can be very beneficial to fracture characterization and its quantification (Liu et.al., 2014).

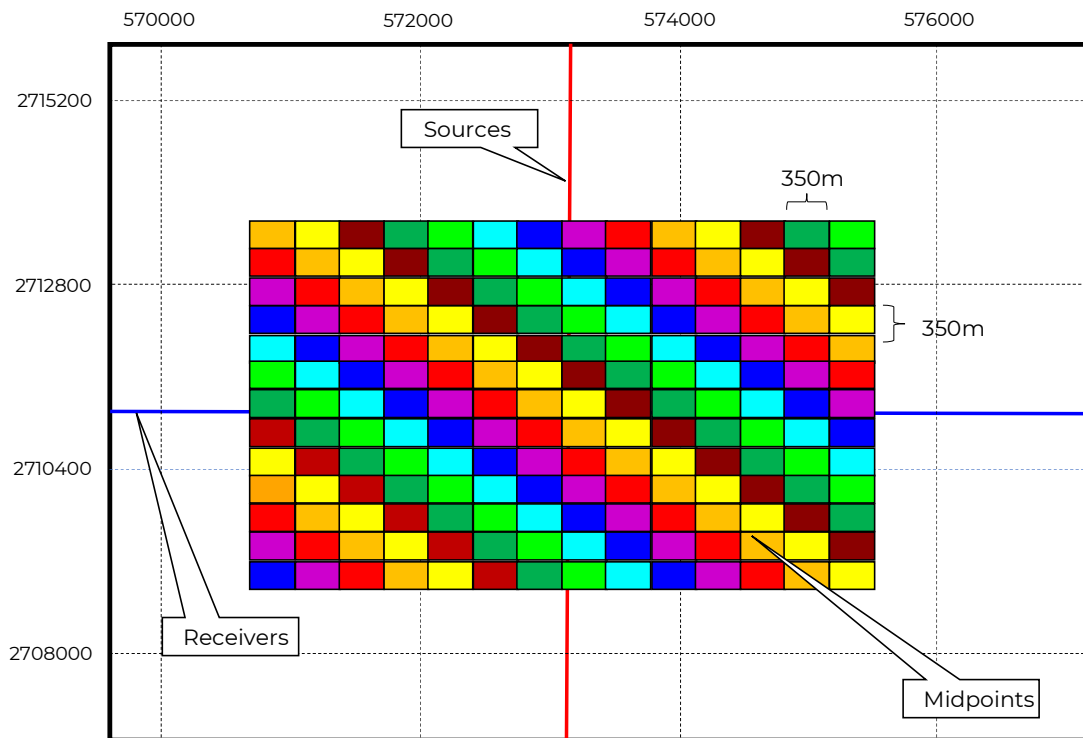


Figure 3.4 Outline of the generation of OVT's, the dimensions of each of the 196 350x350 meters mosaics for this project were generated.

The azimuthal data were processed by fitted elliptical anisotropy from travel times (FEATT) (Greckha and Tsvankin, 1998) by Dowell (Schlumberger) Inc. FEATT is a method on elliptically limited, residual variable velocities. The azimuthal variation of travel time is measured in interval times over CRP gathers that preserved wide azimuth ranges (Figure 3.5).

The velocity functions restricted to an ellipse are adjusted to the perturbations of azimuthal variations in travel times. The outputs of the algorithm are the interval velocity that is spatially and temporally-variant in both the V_{fast} and V_{slow} pathways, the interval azimuth value of the V_{fast} direction, and the RMS error of the adjustment. The adjustment to an ellipse is performed using an algorithm that is robust in the presence of noise. FEATT is capable of separating and extracting the elliptical variations (V_{fast} , V_{slow} , and azimuth) from several layers using the travel times and their changes at defined intervals. The differences can be weak depending on factors such as reflector dip, heterogeneities in the overburden and azimuthal anisotropy (Jenner, 2001).

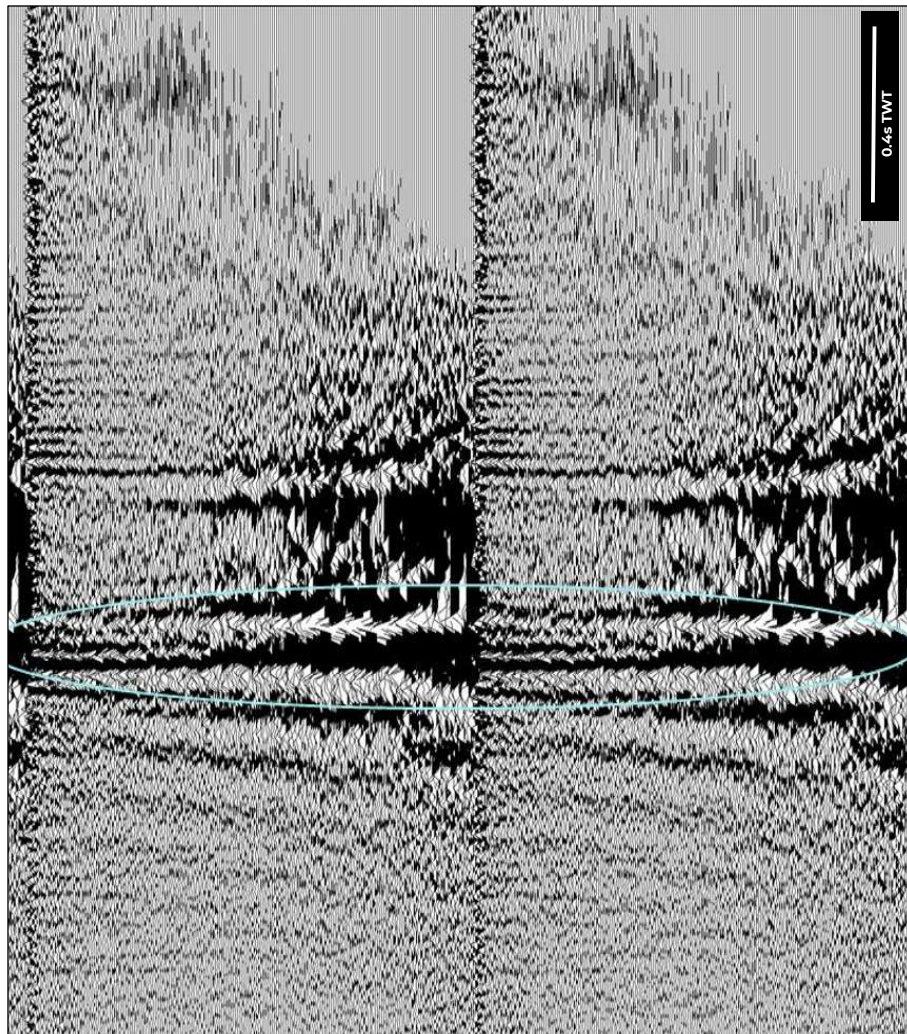


Figure 3.5 CRP gathers sorted in Common offset common azimuth (COCA) with the elliptical correction for anisotropy. These shot gathers show the wobbling effect when the offset increase is more noticeable and those changes in velocities may induce the anisotropy (light blue polygon).

The noise attenuation per azimuthal sector is performed by elliptical NMO correction to obtain better flattening of COCA gathers and more azimuthally stable seismic events through the offset or angle. I performed the noise attenuation and division of the azimuthal data into four sectors using Hampson&Russell commercial software package (Table 3.3 and Figure 3.6).

Gather Sectors	Azimuth
1	(0° -90°)
2	(90° -180°)
3	(180° -270°)
4	(270° -360°)

Table 3.3 Azimuthal sectors

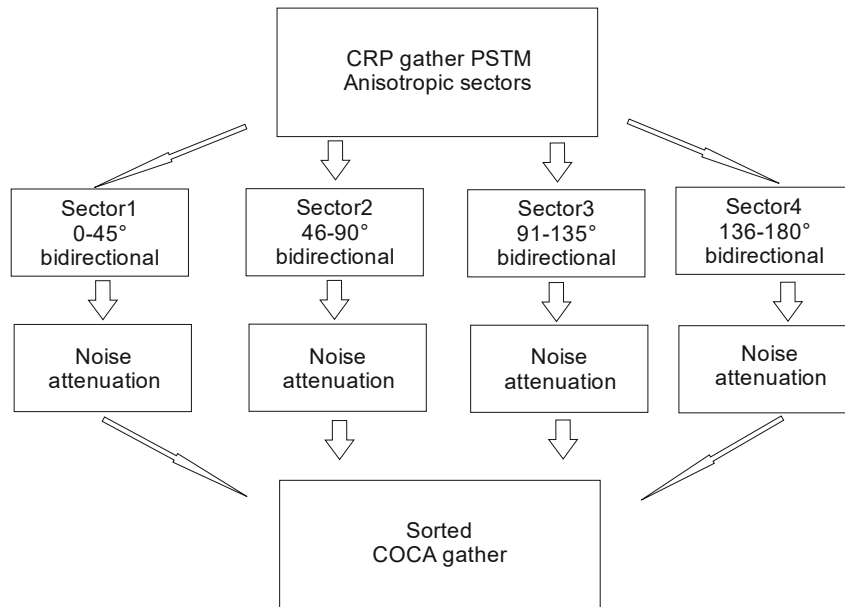


Figure 3.6 Diagram of noise attenuation per azimuthal sector.

The vertical seismic resolution is estimated to be 46 m using the interval velocity and the dominant seismic frequency corresponding to the Pimienta Formation. The amplitude spectrum shows a 24 Hz peak frequency using a Zero phase Ricker wavelet within a time window (1.2-1.5s) (Figure 3.7A-C). To build the wedge model which shows a tuning thickness of 36m I used a python open-source code

which generates a zero-offset synthetic seismic traces from a 3-layer wedge model. This model used the P-sonic, S-sonic and density logs of the well Anhelido-1 assuming a three layer model (Carbonate-Shale-Carbonate). The velocities and densities were taken from logs in the reservoir zone as average values (Figure 3.7B).

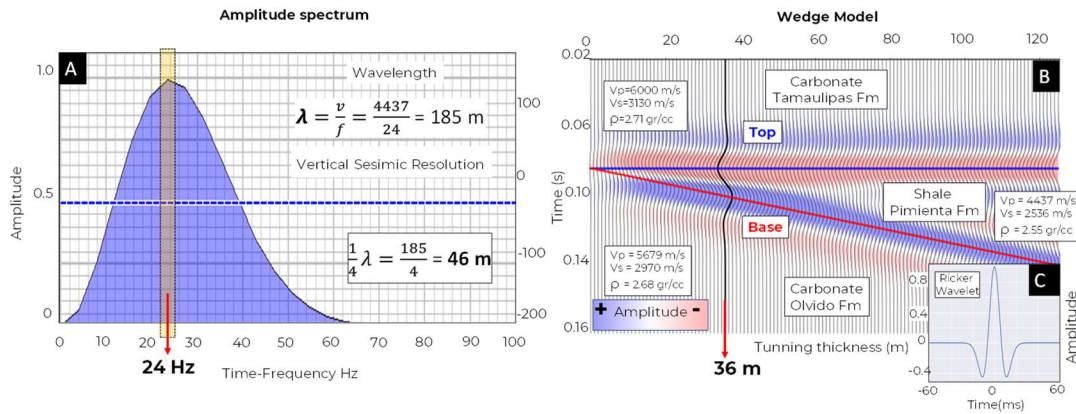


Figure 3.7 (A) Amplitude spectrum and calculation of seismic resolution of 46m using velocity data and seismic frequency within Pimienta Formation using time window TWT (1.2-1.5s) and 24 Hz peak frequency; (B) Wedge model estimation using velocity data; (C) Initial Ricker wavelet of 24 Hz frequency in zero phase associated with Pimienta formation to estimate the tuning thickness of 36m.

3.2.2 Seismic to well calibration

Well log data are commonly used as ground truth to correlate the seismic signal with the earth's stratigraphy (White and Simm, 2003). A wavelet is first estimated from the seismic trace of the 3D volume, and it is then convolved with the reflectivity calculated from the well logs (reflection coefficient from the sonic and bulk density logs). Tying the seismic trace to the well logs aims to minimize the differences in the way, seismic data and well logs data measures the same parameters (Burch, 2002), but with different resolution.

The wavelet is an essential link between seismic data and the stratigraphy. Wavelet estimation is necessary to deconvolve the seismic trace. Well-ties are a critical part to provide correct identification of the stratigraphic markers (White and Simm, 2003, Brown, 2005).

In the stationary case, the seismic trace $s(t)$ can be modelled by convolution of the seismic wavelet $w(t)$, reflectivity $r(t)$ plus noise $n(t)$ (Sheriff and Geldart, 1995).

$$s(t) = w(t) * r(t) + n(t) \quad (3.1)$$

There are two kinds of wavelets that are widely used, the first is the minimum phase wavelet: it has no energy before time zero, and its maximum energy is concentrated at the front. The zero-phase wavelet is symmetric at time zero and is the best for interpretation purposes (Brown, 2005). Both kinds of wavelets are idealized. For this particular case, I used the White-wavelet estimation approach which optimally estimates the seismic wavelet by calibrating and correlating well log data and seismic data from White and Simm (2003). Ideally, there are two steps in this process:

1. Determine the best trace location at which to extract the wavelet using the well.
2. Given that tie location, determine the optimal wavelet.

Typically, the best match rarely occurs at the well location, the best match time location is found scanning many traces around the well for goodness-of-fit, but that fit will depend on the quality of the seismic data, which will have an impact on the confidence in well ties and wavelet extractions.

The well tie calibration of the synthetic and the seismic trace is based on the correlation coefficient (White and Simm, 2003). The nature of the seismic wavelet adds nonlinearities to the trace, which cannot be followed by a linear metric. Thus, wavelet phase mismatches frequently occur between the final processed seismic data and the synthetic seismograms created from well logs. This fact leads to potential complications in stratigraphic and structural interpretation (Van der Baan, 2008). The correlation coefficient is commonly used to measure the quality of the seismic-to-well tie (Hampson-Russell, 1999). For this project I estimated wavelets for six wells using the White approach (Figure 3.8 A-B).

I calibrated wireline data (m) to the seismic information (Prestack time volume) using Checkshot surveys and other time depth transformation constraints from nearby wells. This included standard forward modelling of synthetic seismograms in the Petrel software that usually came from sonic data and density logs and matching them with specific seismic reflections, producing a relationship between the logs (measured in depth) and the seismic (measured in travel time).

For synthetic seismogram generation for the 6 wells, log curves of P-Sonic, S-Sonic and Density were used with an average White wavelet of 24Hz peak frequency (Figure 3.8 A) associated within Pimienta Formation as a window of interest. The next step was to use a depth-time Check Shot Survey from a nearby well that had similar velocity and density characteristics in the reservoir zone. The correlation coefficient for all the wells is 70% on average using markers from the Upper Cretaceous (Mendez Formation), Upper Jurassic (Tamaulipas formation), Upper Jurassic (Top of Pimienta formation), and Upper Jurassic (Olvido Formation) (Table 3.4).

Once the first approach is made, a wavelet is extracted from the well in phase and seismic frequency. The correlation between the amplitudes of the seismic traces near the well and the amplitudes generated by the P-Impedance log of the well which is then verified to corroborate the fit between the synthetic seismogram and seismic trace. The synthetic seismograms are shown in Figure 3.9, Figure 3.10, and Figure 3.11. Finally, after the well calibration process, the interval velocity model was estimated using the well logs for all the wells in the project area. Application of a moving average interpolator from the inverse distance weighting guided by horizon interpretation in the Petrel software suggested good agreement was obtained (Figure 3.12).

The project database contains wireline logs of the six wells, which have been conditioned through the estimation of S-Sonic log due to old wells not having measurements of S-sonic log. These S wave log measurements were estimated for these four wells with no specific S-sonic log as a key step for this study. The data from the six wells used in this project are shown in the well-log correlation (Figure 3.13).

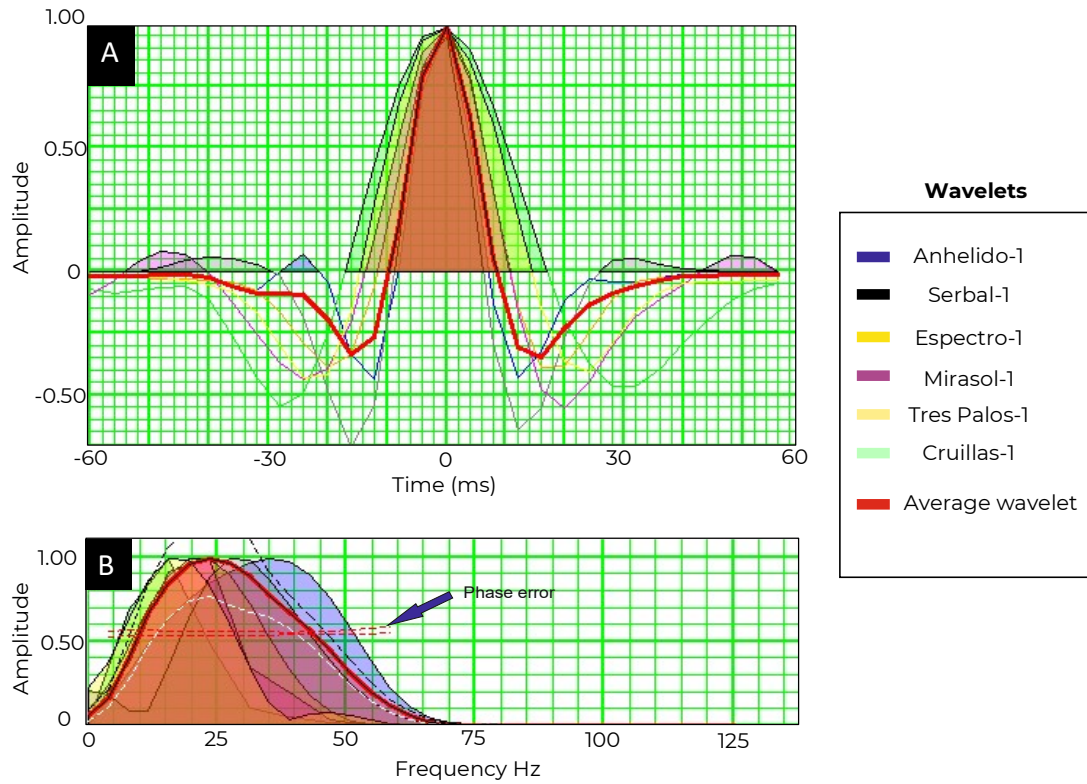


Figure 3.8 (A) Wavelet estimation of 5 wells in the study area within Pimienta Formation with average frequency of 24 hz; (B) Amplitude spectrum of wavelets shown a stable behavior.

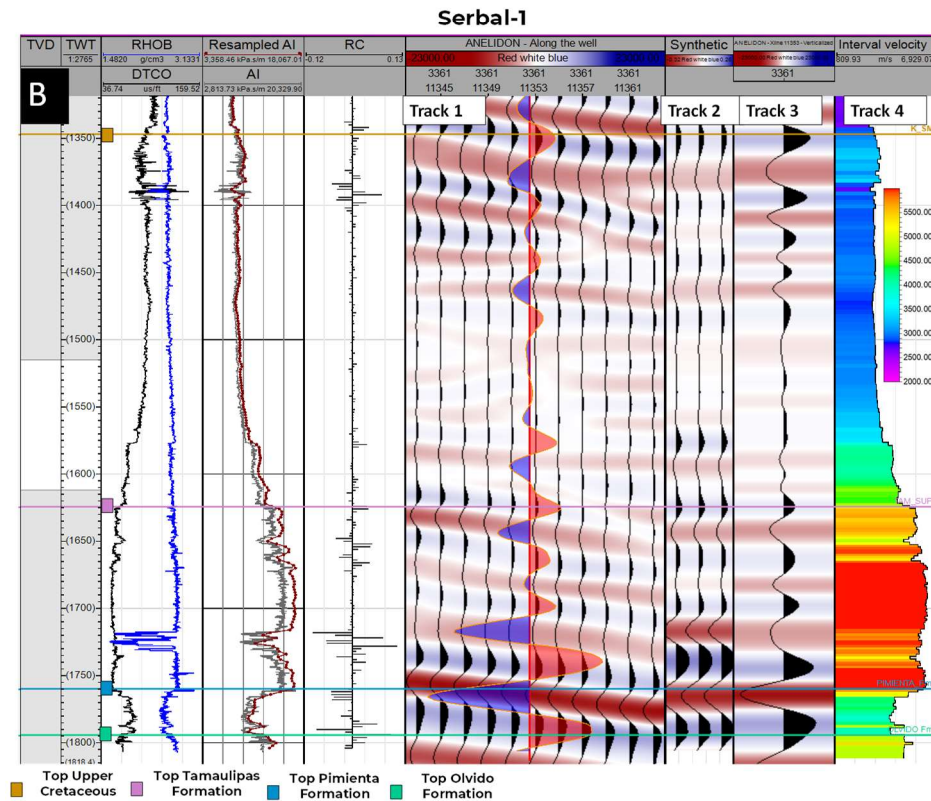
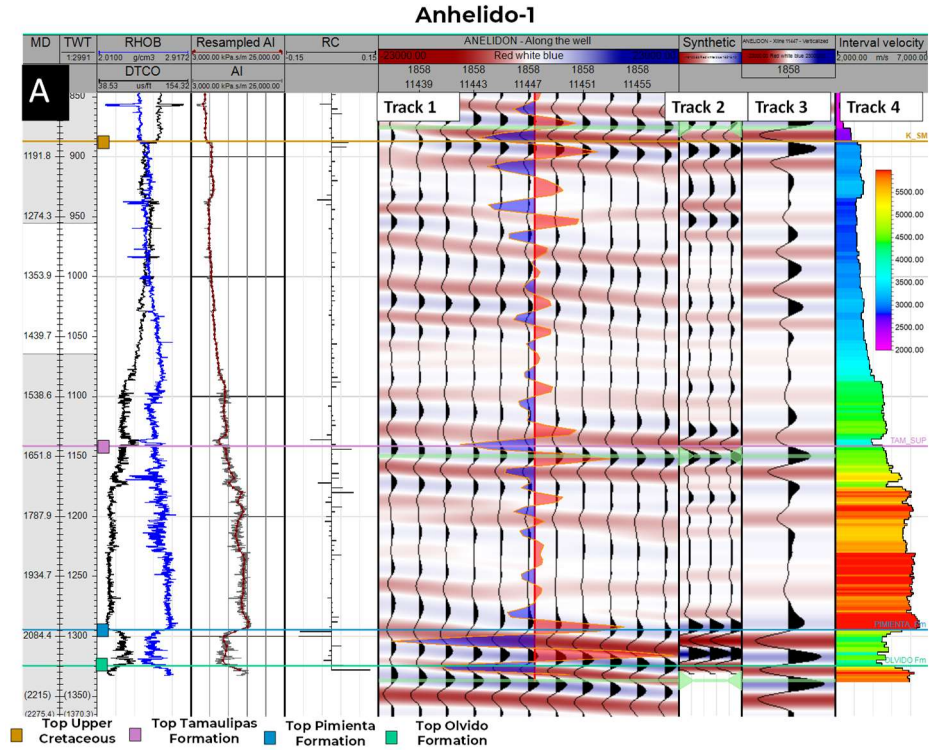


Figure 3.9 Synthetic seismograms showing the match between the seismic trace and the synthetic seismogram. It suggests a good agreement; Track 1 is the 3D seismic survey; Track 2 is the verticalized seismic trace; Track 3 is the synthetic trace; Track 4 is the interval velocity; (A) Well-Tie Correlation of Anhelido-1 (correlation coefficient =72%); (B) Well-Tie Correlation of Serbal-1 (correlation coefficient =73%).

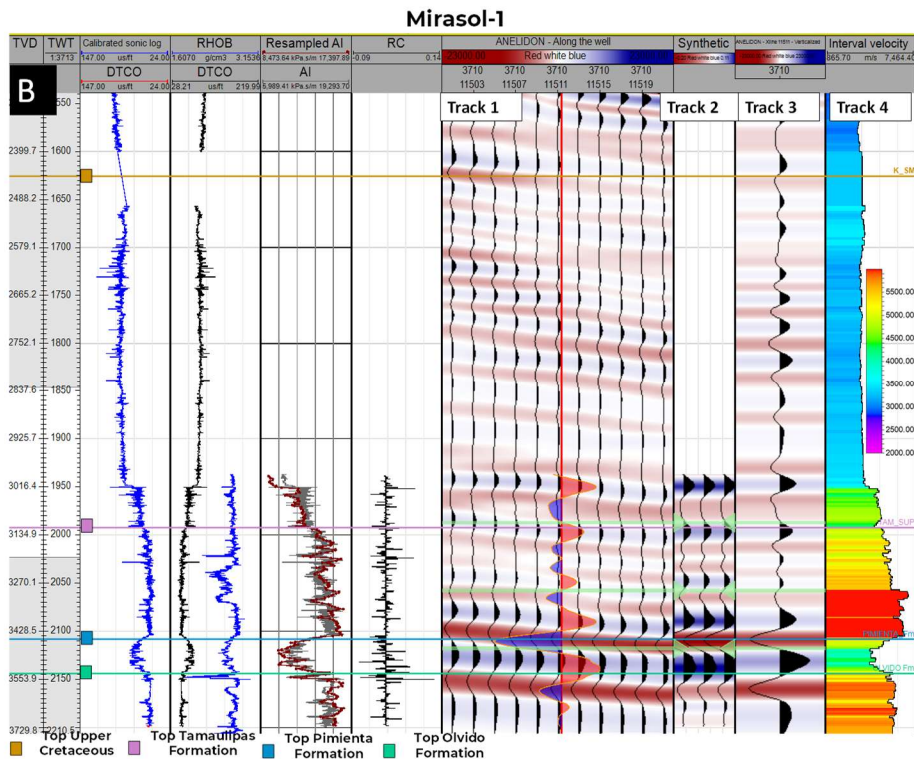
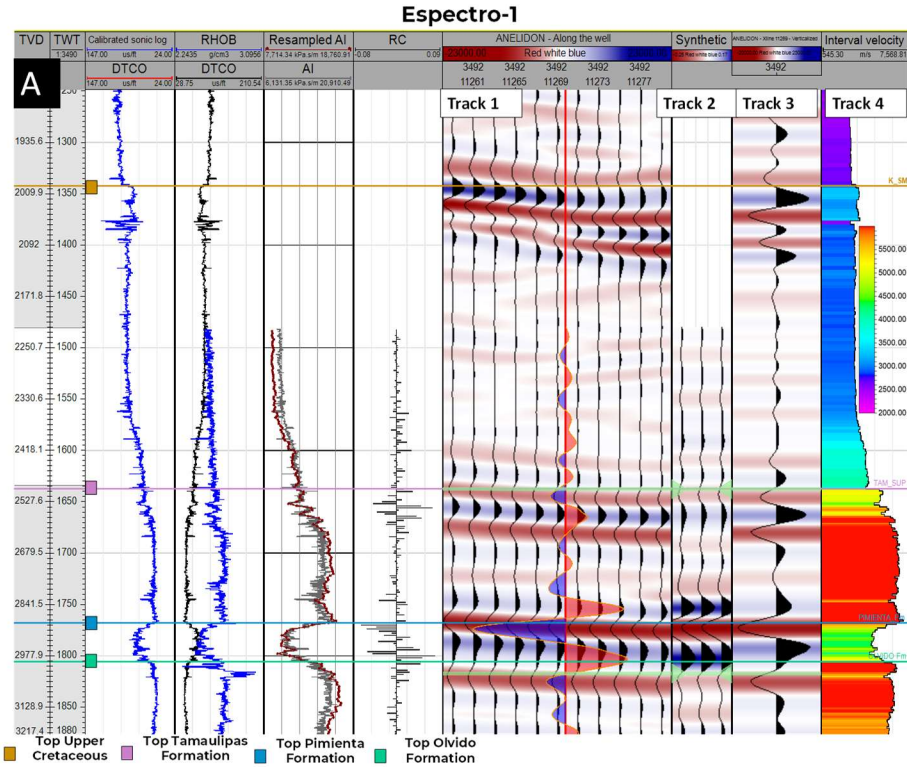


Figure 3.10 Synthetic seismograms showing the match between the seismic trace and the synthetic seismogram. It suggests a good agreement; Track 1 is the 3D seismic survey; Track 2 is the verticalized seismic trace; Track 3 is the synthetic trace; Track 4 is the interval velocity; (A) Well-Tie Correlation of Espectro-1 (correlation coefficient = 71%); (B) Well-Tie Correlation of Mirasol-1 (correlation coefficient = 78%).

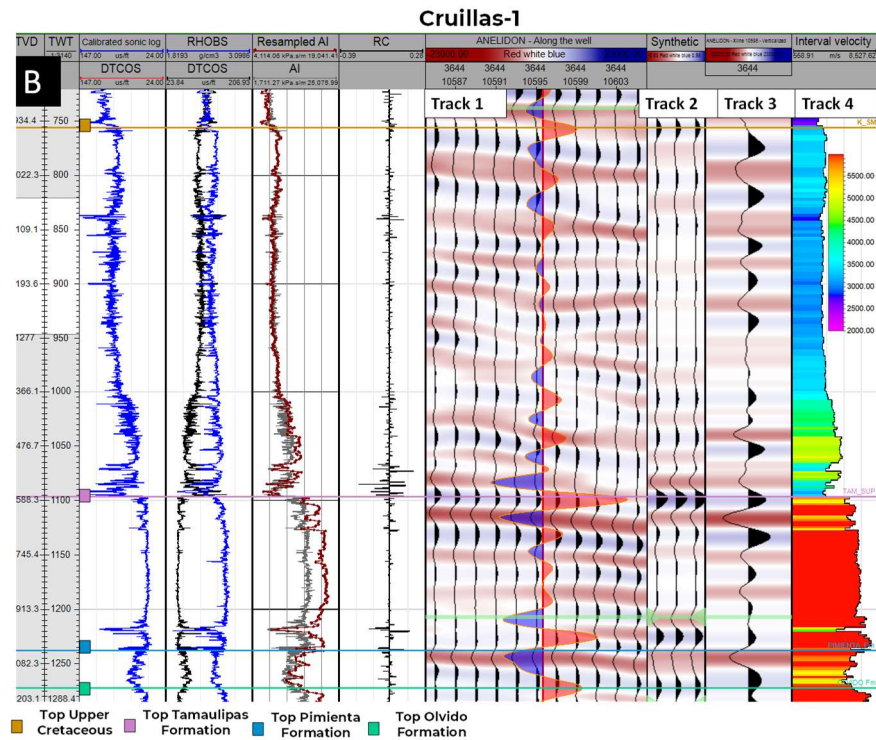
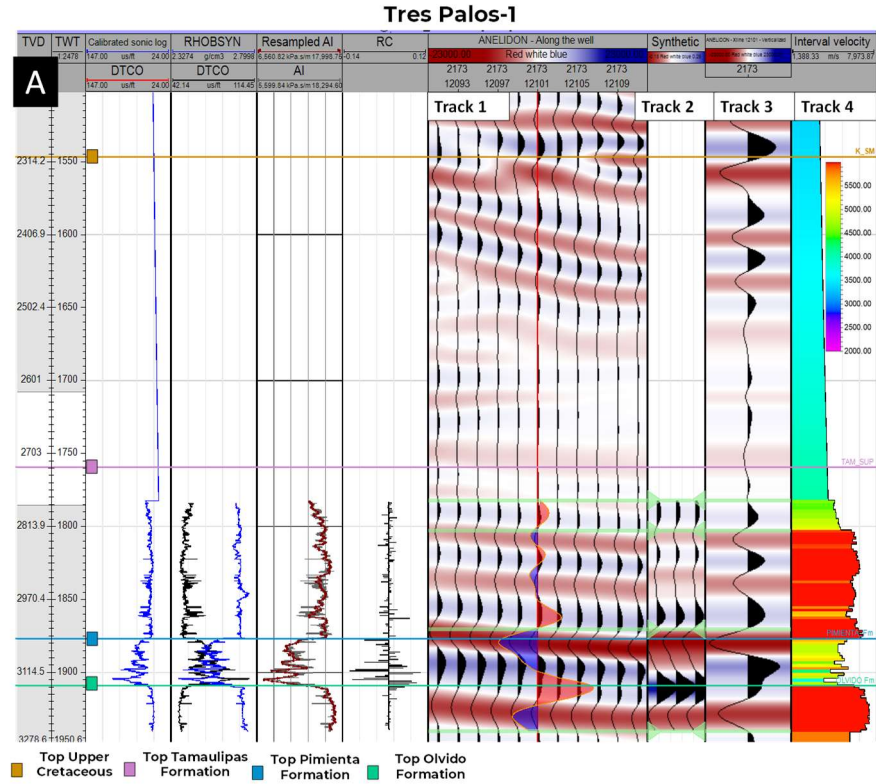


Figure 3.11 Synthetic seismograms showing the match between the seismic trace and the synthetic seismogram. It suggests a good agreement; Track 1 is the 3D seismic survey; Track 2 is the verticalized seismic trace; Track 3 is the synthetic trace; Track 4 is the interval velocity; (A) Well-Tie Correlation of Tres Palos-1 (correlation coefficient = 70%); (B) Well-Tie Correlation of Cruillas-1 (correlation coefficient = 65%).

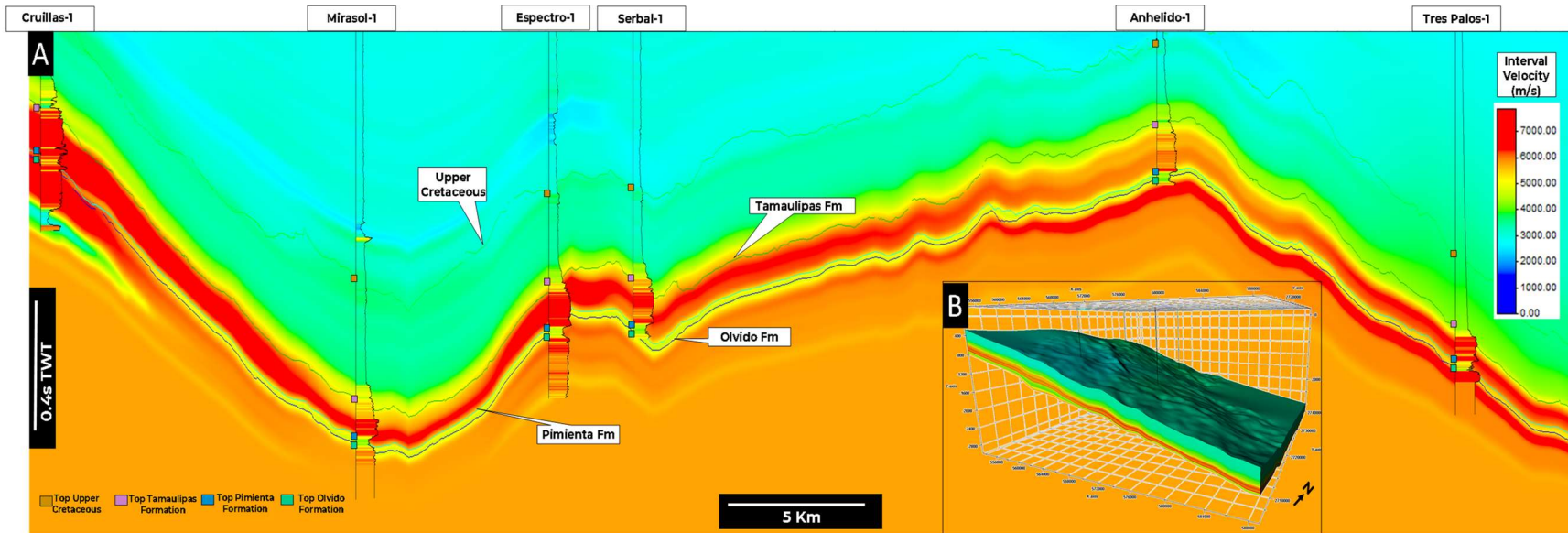


Figure 3.12 (A) Representative arbitrary line from 3D Interval velocity model passing across the study area showing the horizon interpretation and the interval velocity logs in vertical travel time TWT (ms). The model was built using the time surfaces interpreted in this project focused between Upper Cretaceous and Olvido Formation. Note the very good agreement between the velocity model and the interval velocity from logs; (B) Representative 3D velocity model showing the top of Upper Cretaceous (Mendez Formation) and the base Upper Jurassic (Olvido Formation). Note also that the Pimienta Formation has low velocity response.

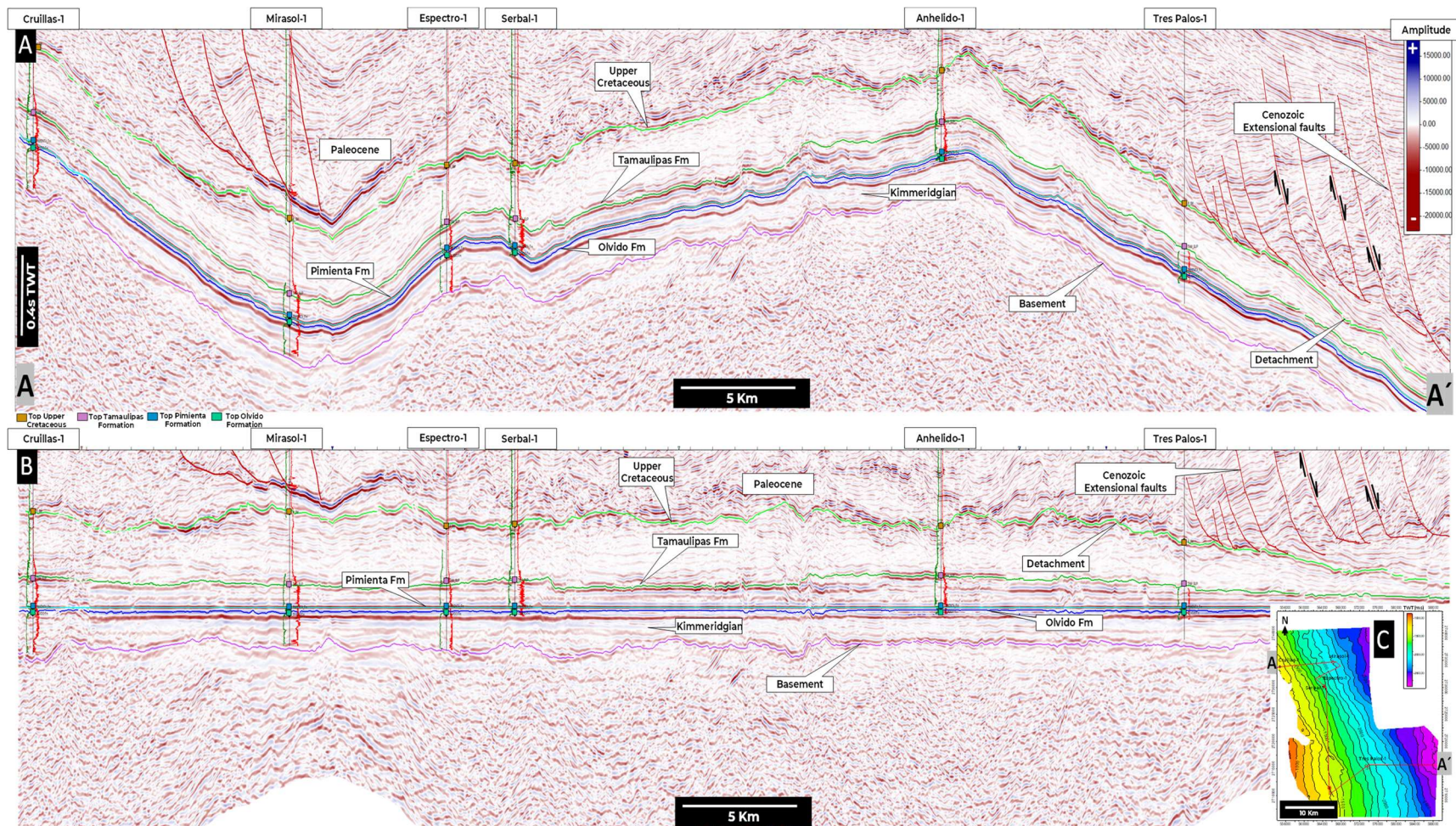


Figure 3.13 (A) Representative seismic line from 3D survey passing across the study area showing the horizon interpretation and the main geological features and logs information Gamma Ray (green) and Resistivity in red color from the Cenozoic sediments to the basement in vertical travel time TWT (ms). The Cretaceous thins at the eastern of the seismic line; (B) Representative seismic line from 3D survey passing across the study area flattened at the top of Pimienta Formation; (C) The arbitrary line A-A' is shown on the map of Pimienta Formation (top) in TWT (ms).

3.3 S wave log prediction

The wireline data set available in this study included two recent L-shaped wells Anhelido-1 and Serbal-1 (they have vertical uphole trajectories and horizontal trajectories into the reservoir). The wireline data were stored and manipulated in the SeisLab library in MATLAB (Figure 3.14). Four of the six available wells do not include a shear sonic log in their wireline coverage, which is very important for rock physics analysis. Hence it was necessary to develop a method to be embedded in the Hampson and Russell software package to estimate this key parameter, as is explained in this section.

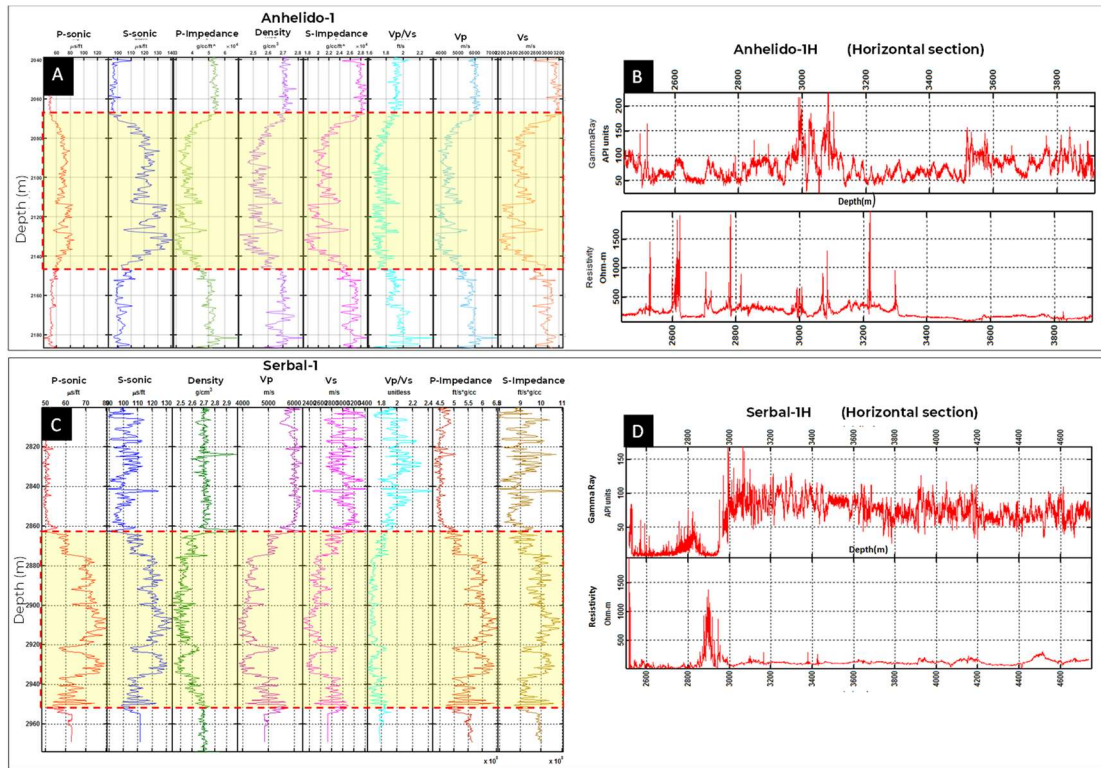


Figure 3.14 (A) Well log data set in Anhelido-1 (Vertical well); (B) Logging in horizontal section of Anhelido-1H. (C) Well log data set in Serbal-1 (vertical well); (D) Logs in horizontal section of Serbal-1H, Pimienta Formation is highlighted in yellow in the vertical wellbores.

S wave prediction is significant component of the seismic inversion process (Castagna et al., 1985; Greenberg and Castagna, 1992; Arild et al., 1999; Bai et al., 2013). Different approaches were used to predict the S wave velocity. Historically procedures to find the linear regression fit between the P-

wave and S-wave curves were developed, the most commonly used S-wave curve prediction method (Castagna et al. 1985) is given by the regression equation:

$$V_s = a * V_p + b \quad (3.2)$$

Vs prediction is based on the knowledge of some key parameters of eq. (3.2). The a and b coefficients are most reliable when are calculated from local wells using Castagna's equation. For this case, the coefficients were determined by applying Multi-Linear Regression Attributes using six wells. MLRA estimation uses five attributes as variables; each target log sample is modelled as a linear combination of attribute samples simultaneously at each depth sample (Figure 3.15 A). The target log is modelled by the linear equation solution for the five weights produced by the standard eq. (3.3) (Russell, 2004)

The results are plotted in the average error graph which shows an excellent correlation of 98% in the cross-plot of real S wave velocity and predicted S wave velocity (Figure 3.15 B).

Multiple regression is an extension of the regression analysis that incorporates additional independent variables in the predictive equation (Balan et al., 1995).

$$\begin{bmatrix} w_0 \\ w_1 \\ w_2 \\ w_3 \\ w_4 \\ w_5 \end{bmatrix} = \begin{bmatrix} N & \sum A_{1i} & \sum A_{2i} & \sum A_{3i} & \sum A_{4i} & \sum A_{5i} \\ \sum A_{1i} & \sum A_{1i}^2 & \sum A_{1i}A_{2i} & \sum A_{1i}A_{3i} & \sum A_{1i}A_{4i} & \sum A_{1i}A_{5i} \\ \sum A_{2i} & \sum A_{1i}A_{2i} & \sum A_{2i}^2 & \sum A_{2i}A_{3i} & \sum A_{2i}A_{4i} & \sum A_{2i}A_{5i} \\ \sum A_{3i} & \sum A_{1i}A_{3i} & \sum A_{2i}A_{3i} & \sum A_{3i}^2 & \sum A_{3i}A_{4i} & \sum A_{3i}A_{5i} \\ \sum A_{4i} & \sum A_{1i}A_{4i} & \sum A_{2i}A_{4i} & \sum A_{3i}A_{4i} & \sum A_{4i}^2 & \sum A_{4i}A_{5i} \\ \sum A_{5i} & \sum A_{1i}A_{5i} & \sum A_{2i}A_{5i} & \sum A_{3i}A_{5i} & \sum A_{4i}A_{5i} & \sum A_{5i}^2 \end{bmatrix} = \begin{bmatrix} \sum L_i \\ \sum A_{1i}L_i \\ \sum A_{2i}L_i \\ \sum A_{3i}L_i \\ \sum A_{4i}L_i \\ \sum A_{5i}L_i \end{bmatrix} \quad (3.3)$$

Where

$$\begin{aligned}
 w_0 &= a & A_{1i} &= P - wave(Vp) \\
 w_1 &= b & A_{2i} &= P - Impedance (Ip) \\
 w_2 &= c & A_{3i} &= Density(r) \\
 w_3 &= d & A_{4i} &= Gamma ray(g) \\
 w_4 &= e & A_{5i} &= Resistivity (RT) \\
 w_5 &= f
 \end{aligned}$$

Therefore, the predicted S velocity gives the next equation:

$$V_s = a * b * A_{1i} + c * A_{2i} + d * A_{3i} + e * A_{4i} + f * A_{5i} \quad (3.4)$$

(Equation from Emerge module theory, on-line guide, Hampson-Russell Software)

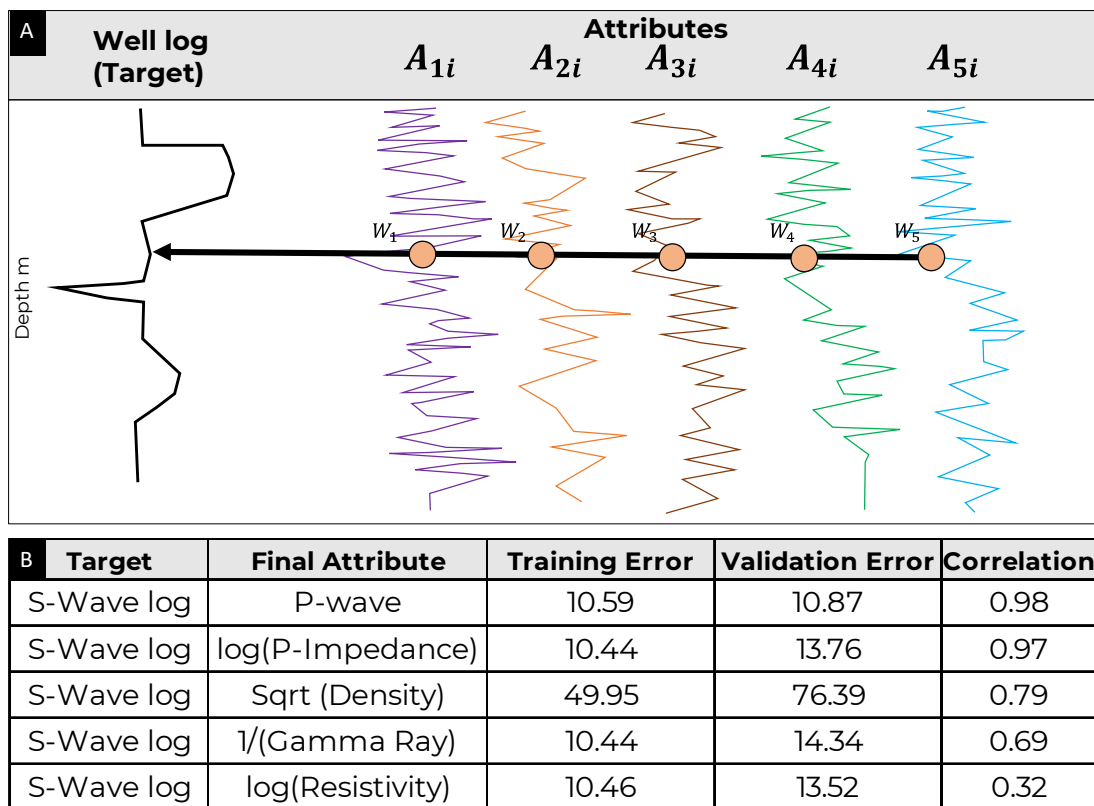


Figure 3.15 (A) Linear combination of attribute samples at the same depth and its weight values; (B) Attributes used for regression to estimate the S-Wave log and its correlation values.

As expected, the result of combining data from the six wells shows that the P-Wave log correlates best, followed by the P-Impedance, Density, Gamma Ray and finally by the Resistivity log (Figure 3.15 B) in the correlation column and the correlation crossplot between S-wave predicted and actual S-wave log in Figure 3.16B.

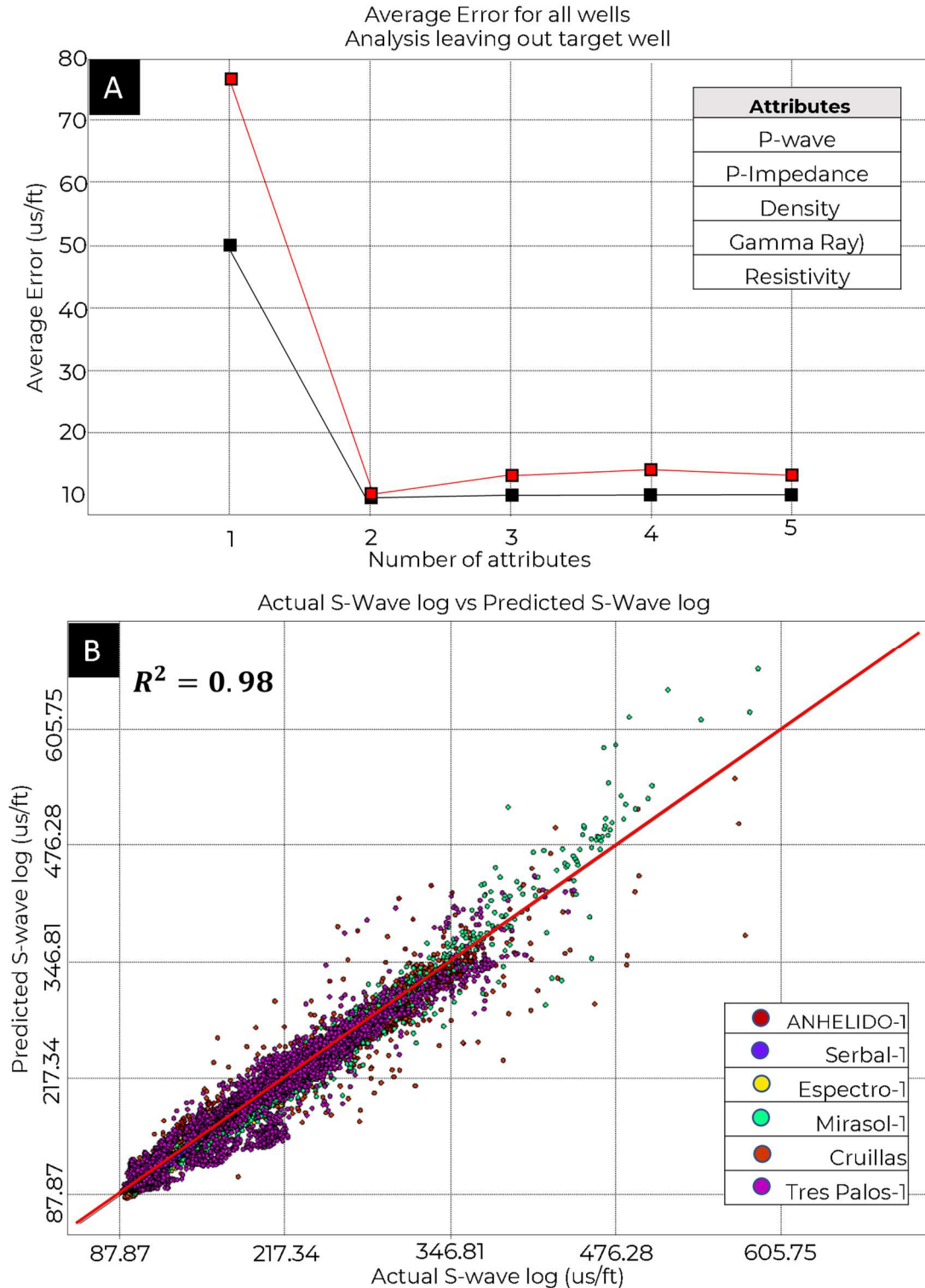


Figure 3.16 (A) The training error is the error using six wells in the prediction, and the cross-validation error is the error in which the well to be predicted is left out of the training; (B) The final correlation in of predicted S wave in the y-axis and the Real S wave in the x-axis show an excellent result of a correlation of $R^2 = 0.98$.

The log attributes and coefficients in equation (3.4) were determined using a technique in which cross-validation is used to determine the optimal ordering of attributes (Hampson et al., 2001). The results of S-wave (S-Sonic log) prediction are shown in Figure 3.17.

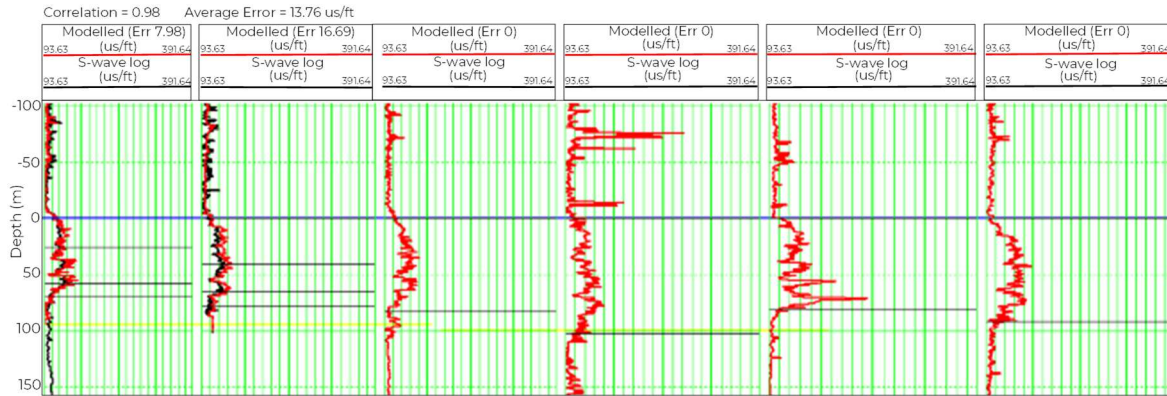


Figure 3.17 Validation of multiple attribute regression in six wells, Average error or Prediction Error shown at the top of the display is the RMS error or difference between the predicted (red) and actual logs (black) within the analysis window flattened at the top of the Pimienta Formation.

The results were considered to be slightly better than those obtained from the linear analysis. Multiple regression presented a robust correlation to predict S wave from wireline log data.

3.4 Conventional TOC estimation and rock brittleness

Total organic carbon is one of the principal parameters to assess the potential of unconventional shale oil/gas resources. Various methods have been published to quantify total organic carbon from well-logs. There are several conventional empirical correlations (Mahmoud et al., 2019):

- (1) directly by regression of core TOC with core bulk density;
- (2) $\Delta\log R$ technique (Passey et al., 1990);
- (3) based on the petrophysical response model;
- (4) using an artificial neural network.

For this particular case, I used the $\Delta\log R$ technique, which estimates TOC by overlapping density and resistivity (Liu et al., 2013).

$$\Delta\log R = \log\left(\frac{R}{R_{bl}}\right) + 2.5 * (\rho - \rho_{bl}) \quad (3.5)$$

$$TOC = \Delta\log R * 10^a \quad (3.6)$$

Where: R=resistivity, R_{bl} =Resistivity Baseline, ρ =Density, ρ_{bl} =Density Baseline

$$LOM = 8.18 * [Ro / [0.59 + 0.41 * [\exp((1 - 2.778 * Ro))]]^{28.45^{1/m}} \quad (3.7)$$

$$m = 2 \text{ (Average)} \quad (3.8)$$

$$a = 0.297 - 0.1688 * LOM \quad (3.9)$$

LOM is the level of maturity determined separately for each source rock. For type II and III source rock, the Tmax vs. Hydrogen Index is plotted for Anhelido-1 and Serbal-1 (Figure 3.16 A-B).

For the estimation of the LOM, it is essential to quantify the cementation exponent value of the rock. I took into consideration published laboratory data of different types of rock carried out by Focke and Munn (1967). These authors determined the cementation (exponent 'm') using different types of rock based on experiment in this case The Pimienta Formation is formed by carbonates with textures of mudstones-wackestone according to petrographic report (PEMEX E&P) with matrix porosity, low permeability rock <0.10, similar to the reservoir parameters for the main focus of this study and slightly fits with the rock type 6.

Therefore, based on this information the cementation exponent for this case low permeability rock <0.10 , and I used this value to compute the LOM value for each corresponding well.

The porosity ϕ is essential to compute the "m" value used in the eq. (3.8), Focke and Munn (1967) research suggested to use value of $m=2$ in average in rock type 6. The Ro Value is determined from pyrolysis experiments which are designed to assess the generative potential and thermal maturity of source rock (Peters, 1986). The LOM value was calculated using eq. (3.7) and compared with the cross-plot of S2 peak versus TOC of core plugs. These values were essential to determine the value of LOM in the Pimienta Formation in Anhelido-1 and Serbal-1.

The LOM for the Pimienta Formation was found to be approximately between 9 and 11 on average in these two wells, respectively. This is corroborated with the output LOM value obtained using Passey's Method in the GUI falling within the oil-prone template for Anhelido-1 with a value of 9.2 and Serbal-1 with 11.3 within the gas prone template. This complements the LOM lines of the of Passey's model for which I have extended this limit (Figure 3.18 A).

Passey et al. (1990) published the original calibration of $\Delta\log R$ which was only for source rocks in the oil maturity window (LOM 6-10.5, %Ro 0.5-0.9). Since no data were available for rocks in the over-mature gas windows (LOM >10.5 , % Ro >0.9) the maturity LOM lines >10.5 were merely mathematical extrapolations.

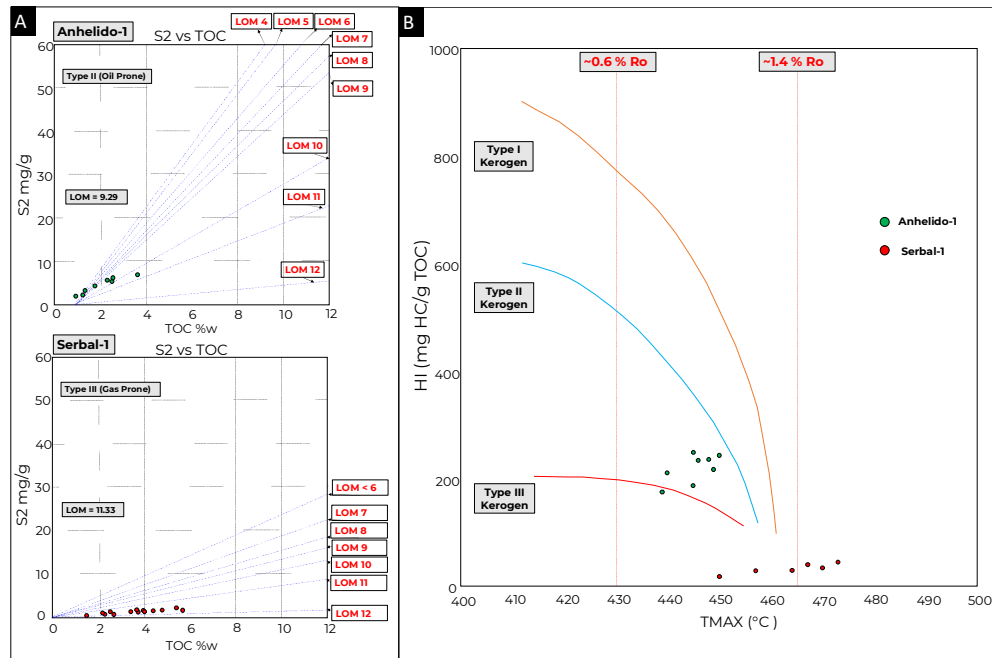


Figure 3.18 (A) LOM value based on Passey et al. (1990); (B) Type of Kerogen for Anhelido-1 & Serbal-1.

Based on this method, the TOC logs were calculated for all five wells in the study area (Figure 3.19), taking into consideration the value of the Vitrinite reflectance R_o as a constraint into eq. (3.6). The R_o average values were taken from Anhelido-1 ($R_o = 0.85$) and Serbal ($R_o = 0.82$). These are the only wells that have pyrolysis data run on samples from within the Pimienta Formation. The pyrolysis data give TOC values which then are compared against the log derived values with good agreement. In this particular case within the source rock, the average value of the hydrogen index is 220 mg HC/g TOC and 37 HC/g TOC for for Anhleido-1 and Serbal-1, respectively.

In contrast, for the other wells where direct TOC samples were not obtained, corresponding to the southern part of the project area near to Anhelido-1, I used a resistivity value of 10 ohm-m, 2.4 gr/cc in density for the non-source rock intervals and $R_o = 0.85$.

For the northern region near to Serbal-1, taking these well outputs as an input value into the equation (LOM equation) to estimate the TOC I used values of 17 ohm-m, 2.7gr/cc for resistivity and density, respectively, in the non-source rock interval and R_o of 1.82.

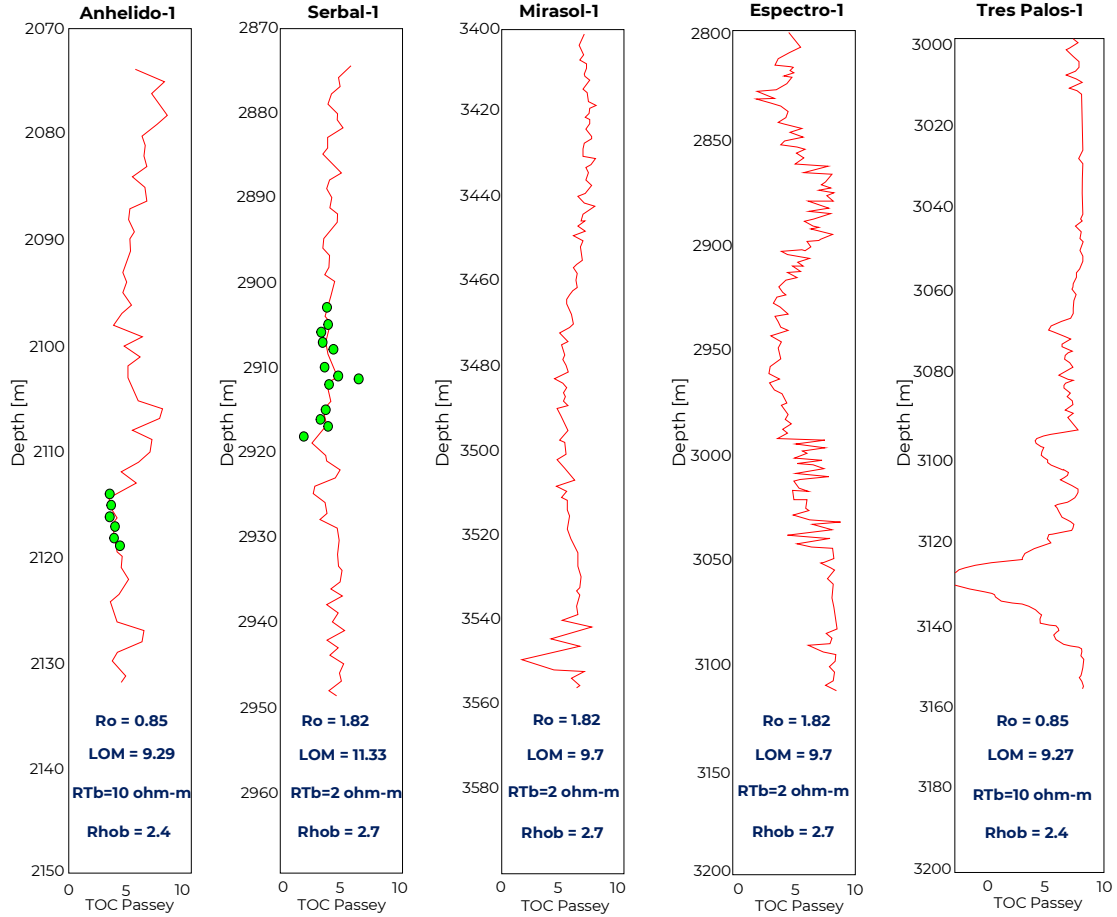


Figure 3.19 Estimation of TOC curves using Passey's formulation constrained with Ro and LOM values in the wells of the study area. The pyrolysis TOC samples are superposed in green with very good agreement.

The Brittleness Index is important to characterize for unconventional plays (Jarvie et al. 2007). However, here is more than one method to determine this property. The one used here is based on Jarvie et al. (2007) and Wang & Gale (2009) where they proposed brittleness index descriptions based on the mineral composition. It is obtained by dividing the most brittle minerals by the sum of the constituent minerals in the rock sample, considering quartz and dolomite (Wang & Gale, 2009) as the more brittle minerals:

$$BI_{Jarvie(2007)} = \frac{Qz}{Qz + Ca + Cly} \quad (3.10)$$

$$BI_{Wang(2009)} = \frac{Qz + Dol}{Qz + Dol + Ca + Cly + TOC} \quad (3.11)$$

Where E_n and σ_n are the normalised Young's Modulus and Poisson's Ratio

$$E_n = \frac{E_{max} - E}{E_{max} - E_{min}} \quad (3.12)$$

$$\sigma_n = \frac{\sigma - \sigma_{max}}{\sigma_{max} - \sigma_{min}} \quad (3.13)$$

Where E , E_{max} , E_{min} are the maximum, and minimum Young's Modulus; σ , σ_{max} , σ_{min} are the maximum, and minimum Poisson's Ratio.

I combined multiple open-source codes to create a single graphical user interface in Matlab (LomLab R1) to calculate the TOC and Brittleness values based on the methods explained previously, i.e., using Passey's method and the Rickman equation. These values were then used as inputs into the software package Hampson and Russell using the modular capability for the subsequent steps during the project work. In addition this approach, allowed the estimation of the elastic Young's Modulus E and Poisson Ratio σ from velocities that could be exported as a text file (Figure 3.20)

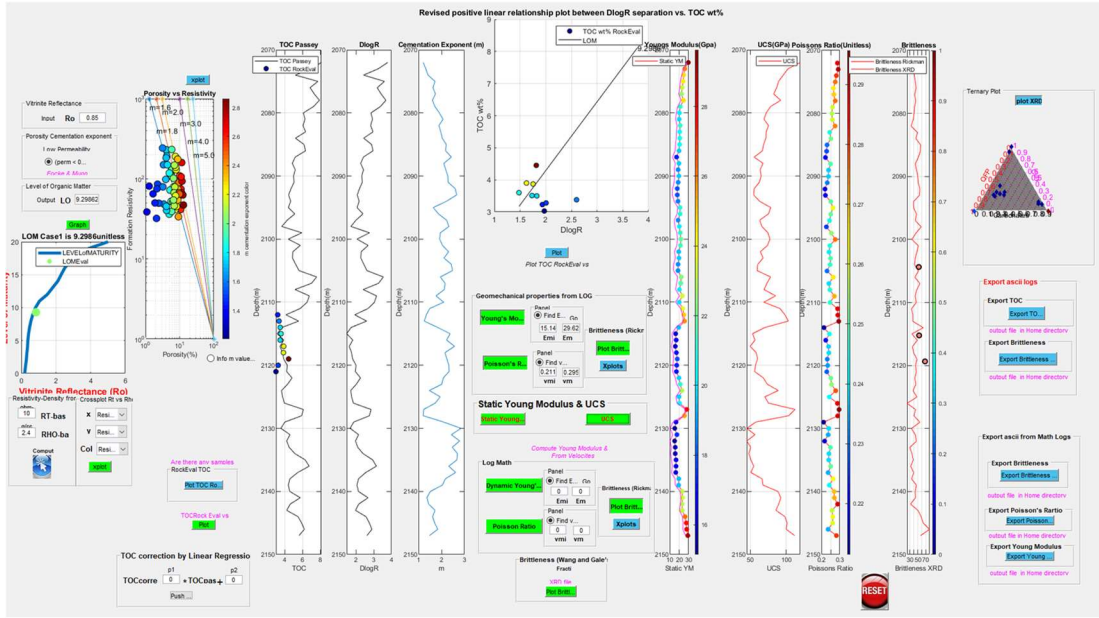


Figure 3.20 LomLab R1 Graphical User Interface to compute TOC and Brittleness index.

Qz is the fractional quartz content, Dol is the dolomite content, Ca is the calcite content, TOC is the total organic carbon, and Cly is the clay content by weight in the rock. The second method where I focused is from Rickman et al. (2008) where they propose a BI brittleness index formula based on Young's modulus and Poisson's ratio.

$$BI_{\text{Rickman}} = \frac{E_n + \sigma_n}{2} \quad (3.14)$$

Due to the small number of samples, brittleness is poorly constrained; however, it is very close to that obtained by the mineralogical content. Therefore, we can assume a preliminary result for its use in future steps (Figure 3.21), which shows how the brittleness index increase is respecting to the elastic Young's in the rock physics crossplot.

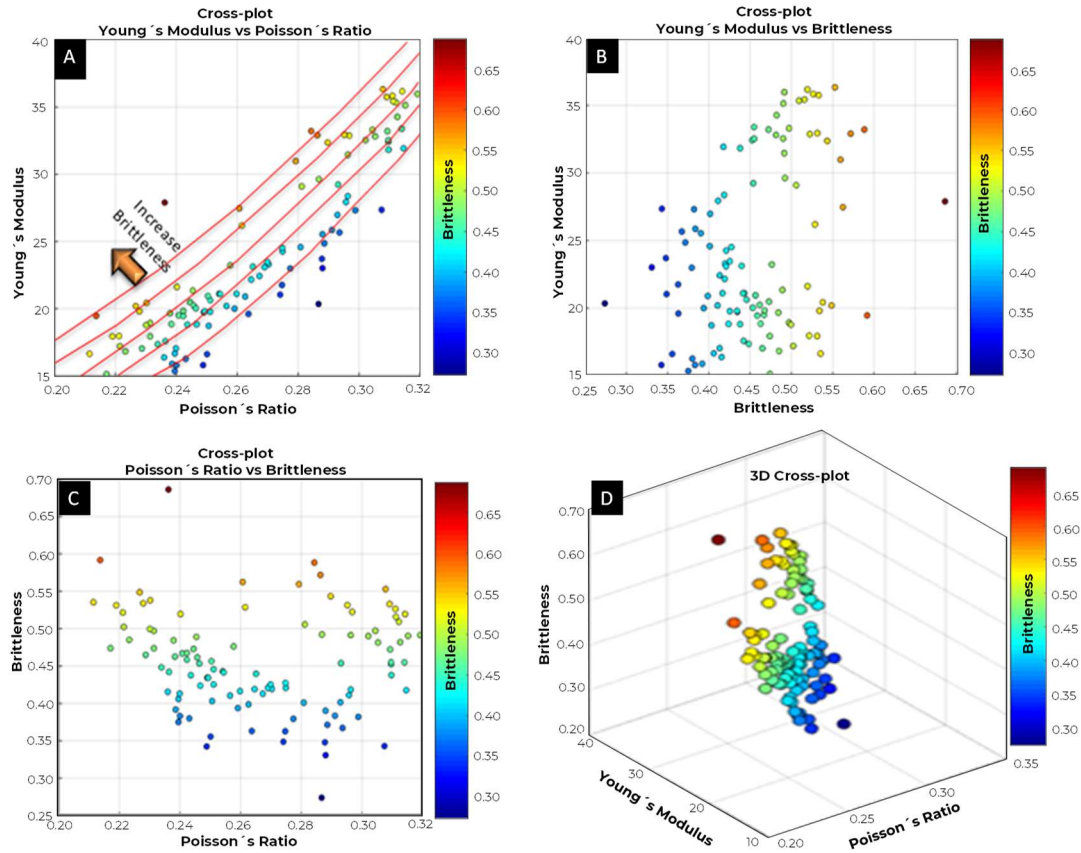


Figure 3.21 Rock Physics cross-plots coloured with Brittleness values in Anhelido-1 within Pimienta Formation (reservoir zone); (A) Cross-plot Poisson Ratio vs Young's modulus; (B) Cross-plot Brittleness vs Young's modulus; (C) Cross-plot Poisson Ratio vs Brittleness; (D) 3D Cross-Plot (Poisson's Ratio, Young's Modulus and Brittleness).

Having calculated the S wave velocity log in all the project wells by this method it is possible to estimate the Young's modulus and Poisson's Ratio and consequently the brittleness index. The estimated conventional brittleness for each well based on Rickman's formula and superposed the values of brittleness based on the Wang (2009) formulation (eq. 3.11) are presented in Figure 3.22.

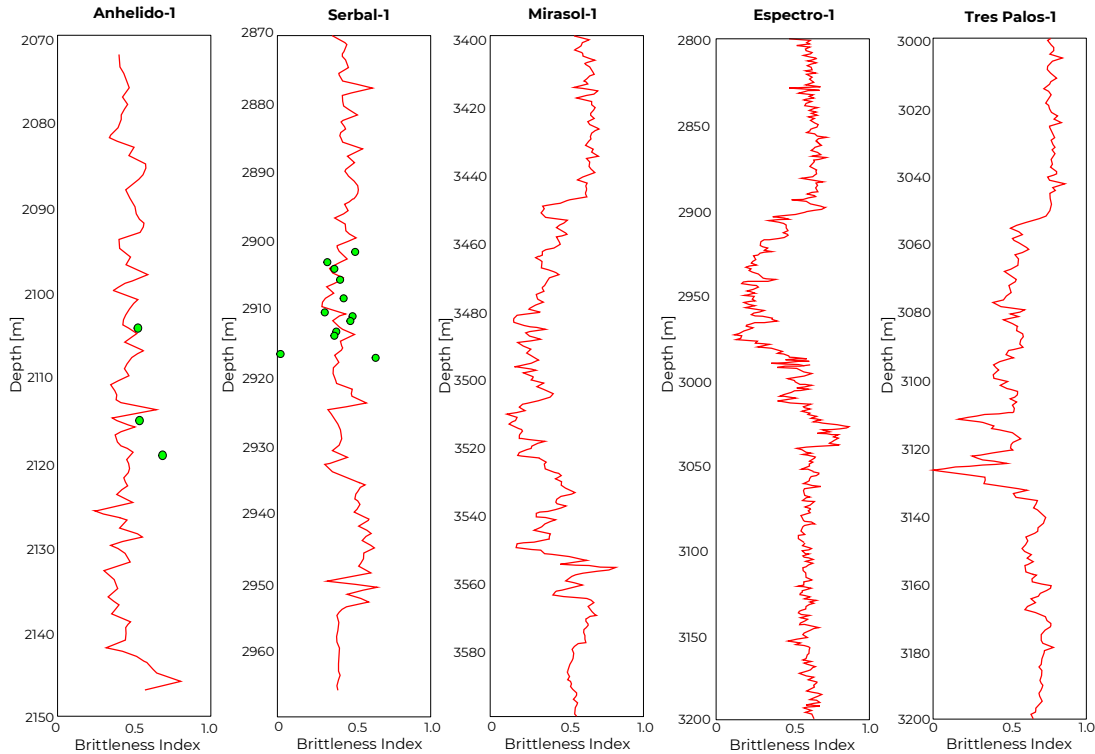


Figure 3.22 Conventional brittleness Index estimation in five wells by using Rickman's equation and brittleness using the Wang approach from XRD data.

Horizon surfaces interpreted in section 3.2 Figure 3.2 the time domain from the Cenozoic to the Jurassic were applied to build the low-frequency model for seismic inversion to compute this property (P-Impedance) . Multi-attribute linear regression was applied to calculate the S wave velocity in the four wells without shear log data within the project area.

The density log was estimated in one well and used to infer the values for the Cenozoic part of the succession and the result of P-impedance (Acoustic inversion) as first approach is shown in Figure 3.23. It may be noticed that there is an excellent match between the P-impedance log with the seismic filter and the inverted P-Impedance volume (acoustic inversion).

Arbitrary Seismic lines of acoustic impedance in Anhelido-1 and Serbal-1 (Figure 3.24 A/B) in the horizontal segment of the borehole show differences in impedances that may potentially be related to lithological changes

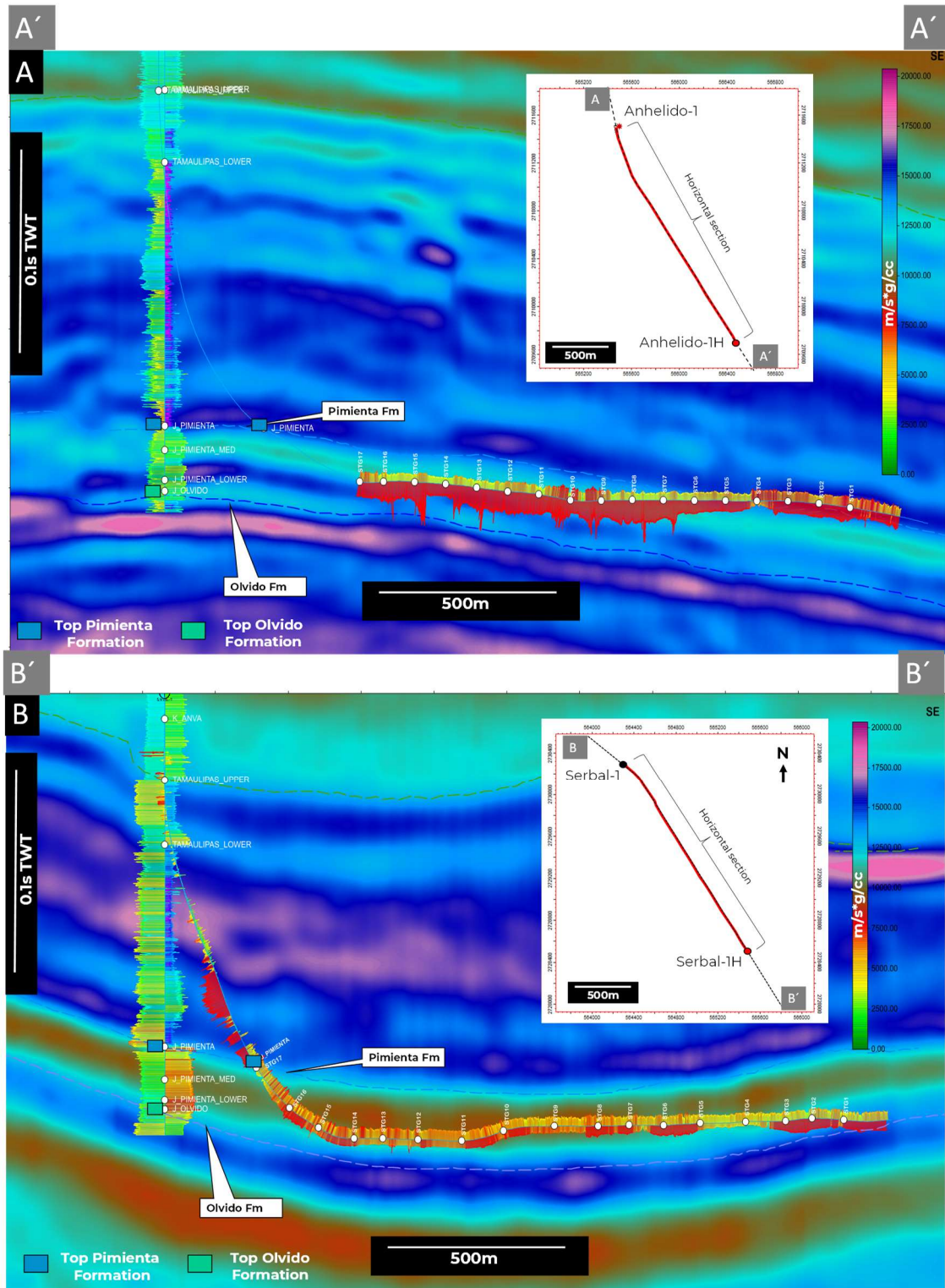


Figure 3.24 (A) Arbitrary acoustic impedance line (A-A') of Vertical and horizontal wellbore Anhelido-1 with displayed gamma ray and resistivity logs; (B) Arbitrary acoustic impedance line (B-B') of Vertical and horizontal wellbore Serbal-1 with displayed gamma ray and resistivity logs. The horizontal well trajectory (red line on the map location) is landing within Pimienta Formation with 17 hydraulic fracturing stages in both wells.

4. Fracture models in effective media

4.1. Introduction

The Pimienta Formation is the most important source rock in the north of Mexico (Quintones, 1991). Several wells have been drilled in this unconventional formation since 2010 where one of the most important challenges has been the understanding of its anisotropy. Anisotropy is a critically important parameter to characterize for this kind of unconventional reservoir. In this Chapter, I will integrate information from well log data and core information to explore the efficacy of different fracture models for seismic detection of fractures through the effective medium theory.

Using this effective medium theory, I will add a novel technique to compute a seismic image in an azimuthal representation in order to be applied to understand the anisotropy associated with the Pimienta Formation. There have been no previous studies using advanced geophysical techniques like these yet applied to the Pimienta Formation.

There are numerous publications of physical models of anisotropy that have been published in recent years. For example, Jenner (2001) developed a trace-correlation to estimate NMO ellipses to wide-azimuth data. Liu (2006) studied kinematic and dynamic anisotropy, and Zhu (2004; 2006) undertook research on the attenuation in a fractured medium through application of the Thomsen theory. Tod et al., (2007) estimated fracture prediction in onshore from wide azimuth seismic data. Tsvankin et al., (2010) gave an overview of seismic anisotropy in exploration and reservoir characterization.

Far et al., (2014) through lab experiments studied the anisotropy and fracture compliances in synthetic fractured media (Plexiglass plates). Experiments were performed using ultrasonic measurements through two anisotropic models to compare the behaviour between a layered medium and layered medium with rubber disc inclusions under controlled uniaxial stress.

In contrast, Ge et al., (2020) studied fracture density in a monoclinic medium using azimuthal AVO for weak anisotropy for shale gas development to properly characterize reservoir reconstruction, establish a fracturing scheme, and calculate porosity and permeability.

The anisotropy in the survey area was analysed from well log data in a specially developed Matlab code that was designed to plot the phase velocity calculated from elastic constants. This was performed in two wells within Pimienta Formation, although there are no conventional core samples, only core photographs.

4.1.1 Anisotropic symmetry classes, particularly the relevance of orthorhombic symmetry to fractured shales

The anisotropic symmetry systems are characterized by the constraints on the stiffness constants. If the medium is symmetric with respect to a certain coordinate transformation, then the stiffness matrix must be invariant under the same transformation.

The symmetry properties of a solid come from its physical constituents and the geometrical arrangement of those constituents. Beside spatial location, constituents themselves should be considered in describing the symmetry as irregular changes in physical properties of the constituents like density can break symmetry. However, there is no need to consider all symmetry properties of a solid for a study of every physical property (Winterstein, 1990)

The symmetry properties of the compliance tensor are the same as those of the stiffness tensor. Constraints applied to compliances are analogous to those applied to stiffnesses, however, they are not always the same.

Voigt notation should be convenient to use in representing the fourth-rank tensors for Hooke's Law. In this notation, the stress and strain tensors are written in vector form and the fourth-rank stiffness

and compliance tensors are shown using 6×6 matrices by following the Voigt rule (Nye, 1985) that $11 \rightarrow 1, 22 \rightarrow 2, 33 \rightarrow 3, 23 \& 32 \rightarrow 4, 13 \& 31 \rightarrow 5, \text{ and } 12 \& 21 \rightarrow 6$

The symmetry property is an actual conceptual transformation of a solid in a way that after transformation the solid is the same as it was before transformation. The symmetry axis is a direction in a solid for which rotations of less than 360 degrees about the direction will no cause change in the solid compared to what it was before rotation (Winterstain, 1990). To identify the symmetry system, it is necessary to understand symmetries, but many interesting cases of such classification can be estimated by exploring how alteration of isotropic rocks creates members of different systems. Winterstain (1990) used a set of homogeneous parallel planar cracks introduced into homogeneous isotropic rock. Combinations of layered media and cracks also can result in different symmetries. For instance, one set of vertical fractures embedded in VTI medium leads to an orthorhombic medium.

The major symmetry systems are:

- Triclinic: As no symmetry at all. Its stiffness matrix has 21 constants.
- Monoclinic: It has a single two-fold symmetry axis, and the stiffness matrix has 13 constants
- Orthorhombic the orthorhombic system has a three orthogonal two-fold symmetry axes. The stiffness matrix has 9 constants.
- Tetragonal: It has a single 4-fold symmetry axes and seven independent constants in its stiffness matrix in general.
- Trigonal; The Trigonal system has a single 3-fold symmetry axis and seven constants in its stiffness matrix.
- Hexagonal: It has a 6-fold symmetry axis where every axis perpendicular to the 6-fold axis is a 2-fold axis and five stiffness constants are required to describe this system

- Cubic: Characterized by three stiffness constants. Its stiffness matrix has the same form as isotropic system, except that the three constants do not satisfy the equality relation governing those of an isotropic system.

Winterstain (1990) proposed five systems formed by arrangements of cracks (Table 4.1)

The symmetry plane is a plane in a solid such that reflection through this plane will cause no change in the solid (Winterstain, 1990).

Conditions: 1. Rock is initially isotropic. 2. Cracks are featureless (smooth and planar), and each crack set has an infinite fold axis, except as noted above. 3. Cracks of different sets are identical except possibly for spacing. 4. Cracks in a set are parallel or distributed symmetrically about the nominal direction. 5. Cracks in set A have spacing a, B have b, etc. 6. Each crack set fills rock uniformly. 7. Crack spacings are much less than a wavelength. 8. Vectors a, b, and d are coplanar. 9. $\alpha, \beta, \gamma, \delta$ are angles between crack plane normals.			
Symmetry System	Crack Set	Crack spacing	Crack normals
Isotropic	(none)	N/A	N/A (Arbitrary) $\alpha \neq n * 90 \text{ degrees}, n = 0,1,2, \dots$ $\alpha \neq n * 90 \text{ degrees}, n = 0,1,2, \dots$
TI	A	a	
Monoclinic	A,B	$a \neq b$	
Orthorombic	A,B	$a = b$ and	

		Or $a \neq b$ and	... $\alpha = n * 90 \text{ degrees}$ $\alpha = n * 90 \text{ degrees}$
Tetragonal	A,B	$a = b$	$\alpha \neq n * 90 \text{ degrees}, n = 0,1,2, \dots$ and
Triclinic	A,B,C	$a \neq b$	$\gamma \neq n * 90 \text{ degrees}, n = 0,1,2, \dots$ $\alpha = \beta = \gamma = 90 \text{ degrees}$
Cubic	A,B,C		$\alpha = \beta = \gamma < 120 \text{ degrees}$
Trigonal	A,B,C		$\alpha \neq 90 \text{ degrees}$
Hexagonal	A,B,D		$\alpha = \delta = 60 \text{ degrees}$

Table 4.1. Symmetry systems and its fracture properties caused by cracks in an isotropic background. Crack set refers to a set of parallel cracks, or a distribution of crack orientations symmetrical direction (Winterstain, 1990).

Notes:

- I. The hexagonal system is actually a symmetry class of the TI system.
2. The tetragonal and trigonal systems are symmetry classes of the tetragonal and trigonal systems, respectively.
3. Several conditions (listed under the diagram) are not necessary but convenient. For example, cracks of different sets would not have to be identical; but if they were not, it would be necessary to state further conditions.

In terms of stiffness matrices, the anisotropic systems are:

Triclinic system:

$$\begin{bmatrix} C_{11} & C_{12} & C_{13} & C_{14} & C_{15} & C_{16} \\ C_{12} & C_{22} & C_{23} & C_{24} & C_{25} & C_{26} \\ C_{13} & C_{23} & C_{33} & C_{34} & C_{35} & C_{36} \\ C_{14} & C_{24} & C_{34} & C_{44} & C_{45} & C_{46} \\ C_{15} & C_{25} & C_{35} & C_{45} & C_{55} & C_{56} \\ C_{16} & C_{26} & C_{36} & C_{46} & C_{56} & C_{66} \end{bmatrix} \quad (4.1)$$

21 constants

Monoclinic system:

$$\begin{bmatrix} C_{11} & C_{12} & C_{13} & 0 & C_{15} & 0 \\ C_{12} & C_{22} & C_{23} & 0 & C_{25} & 0 \\ C_{13} & C_{23} & C_{33} & 0 & C_{35} & 0 \\ 0 & 0 & 0 & C_{44} & 0 & C_{46} \\ C_{15} & C_{25} & C_{35} & 0 & C_{55} & 0 \\ 0 & 0 & 0 & C_{46} & 0 & C_{66} \end{bmatrix} \quad (4.2)$$

13 constants

Orthorhombic system:

$$\begin{bmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\ C_{12} & C_{22} & C_{23} & 0 & 0 & 0 \\ C_{13} & C_{23} & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{66} \end{bmatrix} \quad (4.3)$$

9 constants

Tetragonal system:

$$\begin{bmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & C_{16} \\ C_{12} & C_{11} & C_{13} & 0 & 0 & -C_{16} \\ C_{13} & C_{13} & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{44} & 0 \\ C_{16} & -C_{16} & 0 & 0 & 0 & C_{66} \end{bmatrix} \quad (4.4)$$

7 constants

Trigonal system:

$$\begin{bmatrix} C_{11} & C_{12} & C_{13} & C_{14} & -C_{25} & 0 \\ C_{12} & C_{11} & C_{13} & -C_{14} & C_{25} & 0 \\ C_{13} & C_{13} & C_{33} & 0 & 0 & 0 \\ C_{14} & -C_{14} & 0 & C_{44} & 0 & C_{25} \\ -C_{25} & C_{25} & 0 & 0 & C_{44} & C_{14} \\ 0 & 0 & 0 & C_{25} & C_{14} & C_{11} - C_{12}/2 \end{bmatrix} \quad (4.5)$$

6 constants

Hexagonal system:

$$\begin{bmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\ C_{12} & C_{11} & C_{13} & 0 & 0 & 0 \\ C_{13} & C_{13} & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{44} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{11} - C_{12}/2 \end{bmatrix} \quad (4.6)$$

5 constants

Cubic system:

$$\begin{bmatrix} C_{11} & C_{12} & C_{12} & 0 & 0 & 0 \\ C_{12} & C_{11} & C_{12} & 0 & 0 & 0 \\ C_{12} & C_{12} & C_{11} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{44} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{44} \end{bmatrix} \quad (4.7)$$

3 constants

Different distributions of fractures and their orientation may result in different anisotropic systems. The anisotropic properties can be studied using seismic surface, VSP or other techniques in the geophysical field to identify fractured regions.

Orthorhombic symmetry for shales

Orthorhombic symmetry is commonly formed by embedding a set of parallel vertical fractures in the VTI background (Figure 4.1) or by embedding two sets of orthogonal and vertical fractures in either an isotropic or VTI background. Can be formed as well by combining two sets of conjugate fractures dipping with angle θ and $-\theta$ (Reiss, 1980; Nelson, 1985; Sayers, 2022).

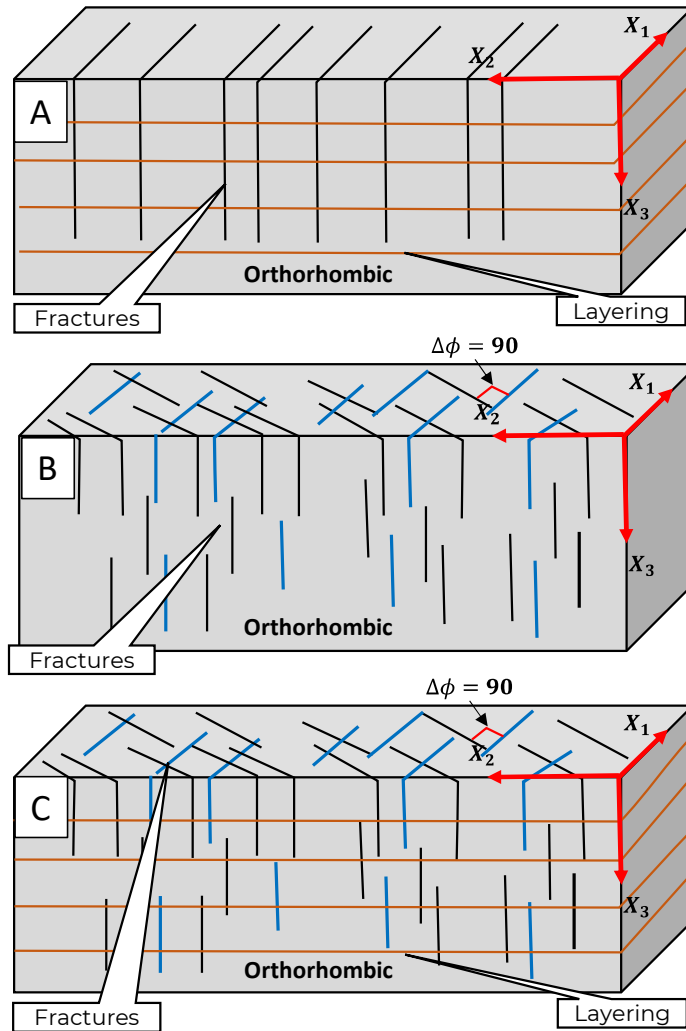


Figure 4.1 Orthorhombic symmetry is commonly formed by embedding a set of parallel vertical fractures in VTI background.

In general shales exhibit VTI anisotropy due to bedding planes, thin layers with preferred alignment of clay platelets and organic materials, and horizontal cracks or fractures (Thomsen, 1986; Wang, 2002). The interfaces can be treated as linear-slip interfaces where discontinuity is linearly dependent on the traction vector on the interface (Schoenberg, 1980).

In sedimentary basins, orthorhombic symmetry is commonly caused by parallel vertical fractures embedded within a VTI background medium (Figure 1b). It may also arise due to two or three mutually orthogonal fracture sets, or due to two identical fracture systems cross-cutting one another with an arbitrary angle (Tsvankin, 1997). Such sets of fractures are common, e.g., for thick sandstone

beds and granites. Bakulin et al. (2000b) conclude that orthorhombic symmetry thus might be the most realistic symmetry for many geophysical problems. Despite this conclusion, the application of orthorhombic anisotropy in seismic inversion and processing is impeded by the large number (nine) of independent entries of the stiffness matrix. Moreover, if the orientation of the symmetry planes is unknown, as it is usually the case in seismic field experiments that the number of unknowns increases to 12, since the angles between the symmetry planes and the coordinate planes of the reference observation system must be determined additionally.

4.2. Data and methods

The dataset used in this chapter is a combination of porosity and clay volume fraction derived from well log data of two boreholes Anhelido-1 and Serbal-1 located in the north and south of the study area. These two wells are spaced 18.7 km apart (Figure 3.1). This data set has been used to estimate the average value of the empirical relations between ultrasonic, V_{Sdry} and ρ_{dry} only for the case of dry rock within the Pimienta Formation.

The depth range of the Pimienta Formation in Anhelido-1 is 2070-2152m and 2863-2951m in Serbal-1. There are core images available from both wells to observe the fracture geometry and their existence within the formation; these images have been used to inform the modelling used in this chapter.

The method used in this chapter is based on Han (1986). His empirical relations between ultrasonic V_p and V_s in (Km/s) were determined from 70 samples of shaly sandstone under dry condition at 40 MPa pressure. The empirical relations derived by Han are:

Dry case

$$V_{pdry} = 5.41 - 6.35\phi - 2.87C \quad (4.8)$$

$$V_{sdry} = 3.57 - 4.57\phi - 1.85C \quad (4.9)$$

Where C is the volumetric clay content in the rock and ϕ rock porosity both properties being derived from well-log data.

This information is needed to perform the fracture models for effective media because the dry rock velocities are required.

For fracture models there are two widely used techniques in effective medium theory (Hudson, 1980; Schoenberg, 1980) which provide the link between the elastic properties determined from seismic data and the physical characteristics of fractures. For the project, I will focus on the Hudson penny-shaped crack model based in ellipsoidal cracks which represent this shale rock model (Figure 4.1) and the Schoenberg's linear-slip model representing fracture planes of weakness.

The main difference in these methods is that Hudson's model assumes that fractures are aligned isolated penny-shaped cracks, while Schoenberg's linear slip model conceptualise fractures as imperfectly bonded interfaces.

From 2111-2112m depth in Anhelido-1 there are examples of vertical fractures in the core data (Figure 4.2 A) and a sample rich in organic matter matrix. It contains abundant fine-grained host carbonates with kerogen filled penny-shaped cracks in this interval of the Pimienta Formation (Figure 4.2 B) primary kerogen (Ro, type III) with an average value of 0.85. The source rock is rich in clay but also contains quartz, carbonate, and a significant occurrence of micronodular pyrite. The Hudson's model is based on this ellipsoidal shaped crack in the medium. This is to some extent validated by the observations of core from Serbal-1 where there is evidence of vertical, carbonate-cemented fractures in the core sample at 2908-2910m depth (Figure 4.3), although the precise three-dimensional geometry of these fractures is not known.

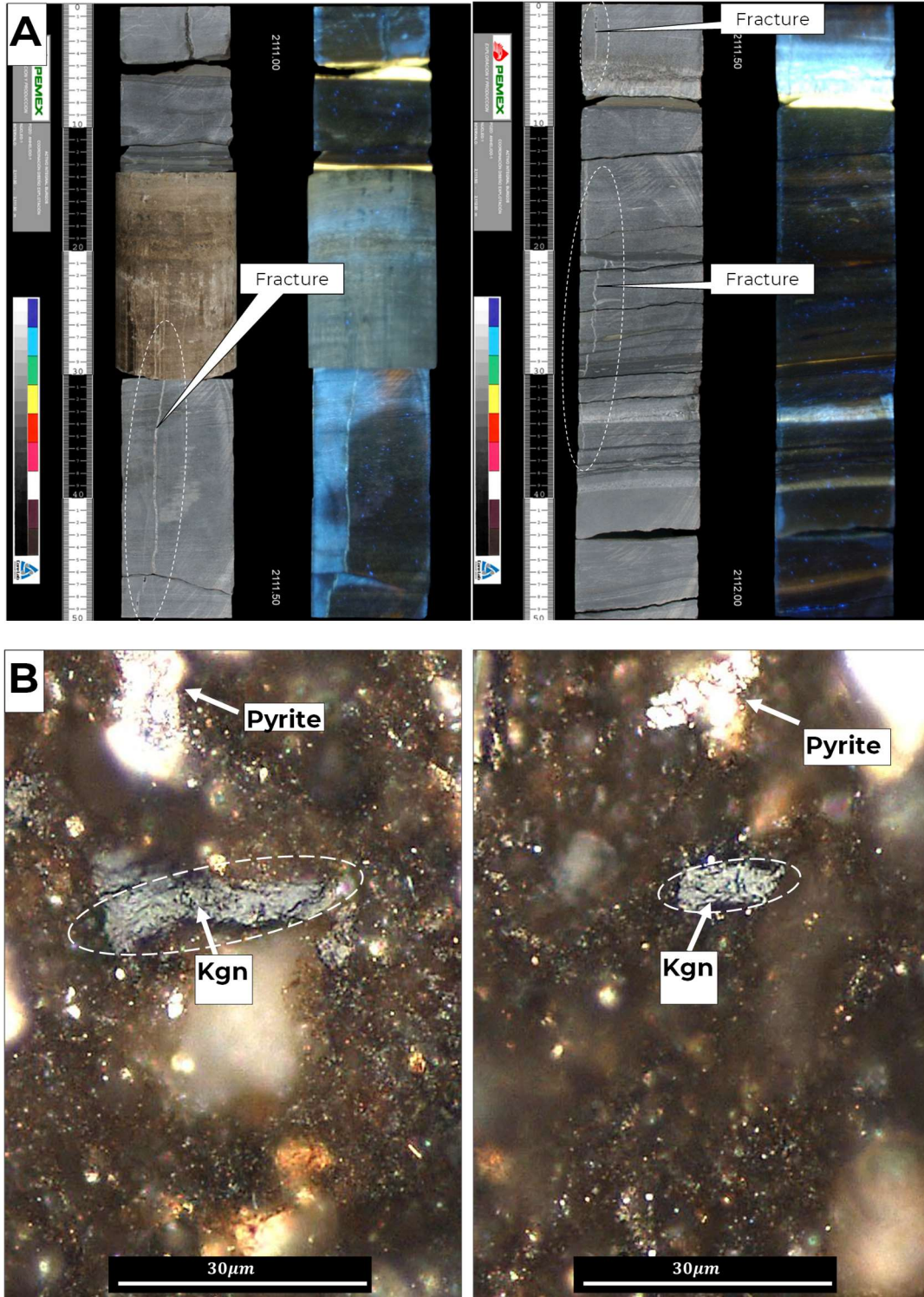


Figure 4.2 (A) Evidence of vertical fractures at 2111-2112m depth; (B) Penny-shaped cracks that are kerogen filled and associated with disseminated pyrite.

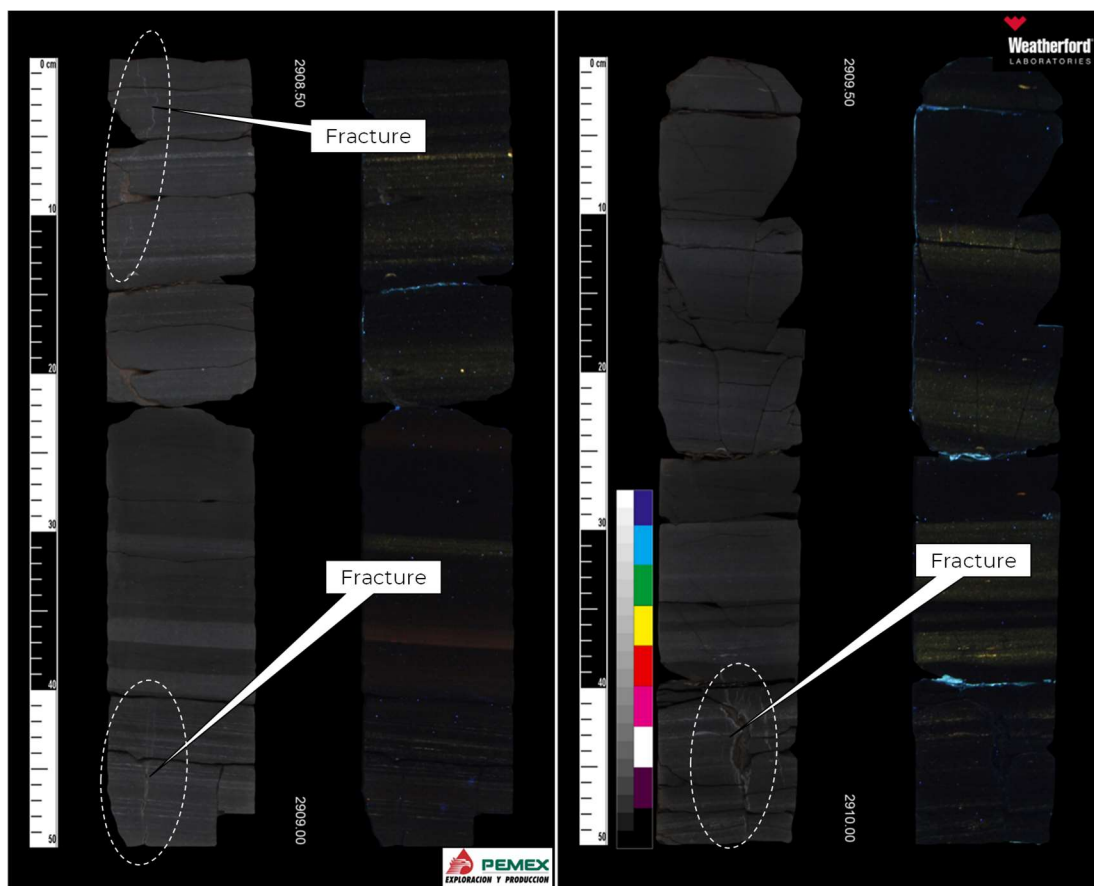


Figure 4.3. Evidence of vertical fractures cemented by calcite (veins) at 2908-2910m depth for Serbal-1

4.2.1 The Hudson Model

Fractures in a shale formation may potentially result in changes in amplitude and velocity of the seismic response such as low velocity, attenuation, and anisotropy. The Hudson model is widely applied to predict the nature of the fractured medium by defining the elastic properties in which penny-shaped cracks have an ellipsoidal crack geometry (Figure 4.4). The crack density (e) is used in the Hudson model, and the pore aspect ratio (α) exhibit an ellipsoidal shape.

The pore aspect ratio is defined as the ratio between the long and short axis of the penny-shaped crack. The crack density is represented as:

$$e = \frac{n}{V} a^3 = \frac{3\phi}{4\pi\alpha} \quad (4.10)$$

Where a is the crack radius, N/V is the number of cracks per unit of volume and the crack induced porosity is represented by ϕ .

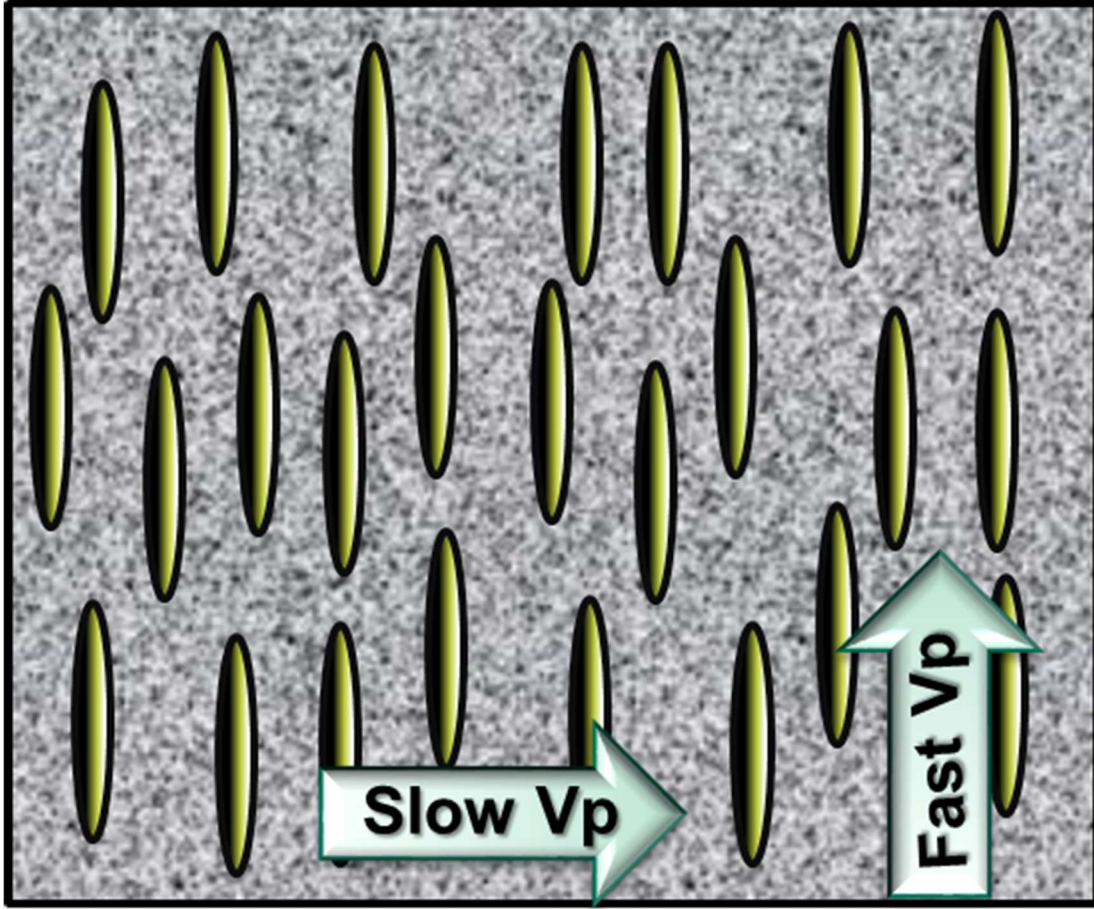


Figure 4.4. Hudson's Model – Penny-Shaped cracked model (modified from Hudson, 1981).

For the Hudson model involving isolated penny-shaped cracks embedded in an isotropic host rock as illustrated in Figure 4.4, the Thomsen's equations can be re-written to estimate the anisotropic values for the dry case, substituting the weaknesses terms to be represented as Thomsen's notation as follows:

$$\varepsilon^{(V)} = -\frac{8}{3}e \quad (4.11)$$

$$\gamma^{(V)} = -\frac{8e}{3(3-2g)} \quad (4.12)$$

$$\delta^{(V)} = \varepsilon^{(V)} \left[1 + \frac{g(1-2g)}{(3-2g)(1-g)} \right] \quad (4.13)$$

Therefore, the Thomsen's parameters from the above equations become a function of the value of crack density.

Where g is the background medium.

4.2.2 Schoenberg linear-slip model

For the linear slip model, Schoenberg's (1980, 1983, 1989) (Figure 4.5) represents planes of weakness infinitely extended regardless of microstructure and shape. The planes of weakness with linear-slip boundary conditions are based on the Backus average. These two characteristics are equal in the long wavelength limit proposed by Schoenberg (1980) for a single interface in elastic medium (Schoenberg and Sayers, 1995; Schoenberg and Nakagawa, 2006).

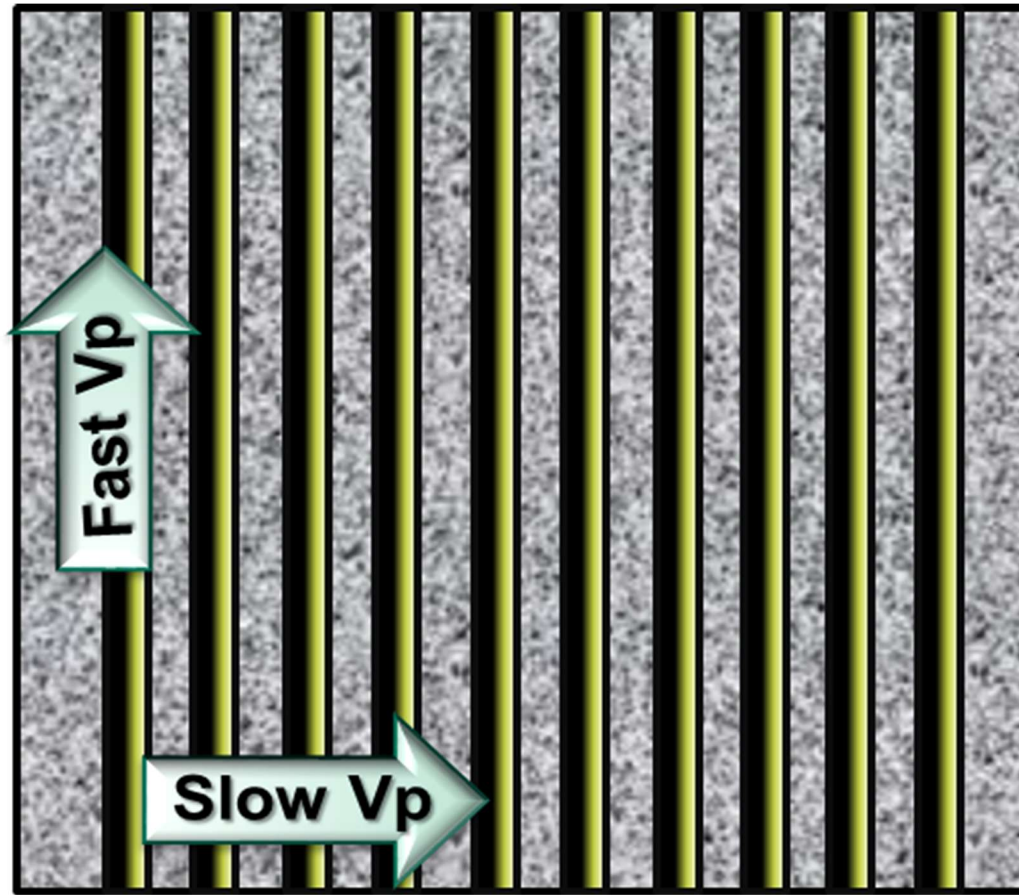


Figure 4.5 Representation of Schoenberg's Linear-Slip model for fractured rock with infinitely long planes of weakness (modified from Schoenberg, 1983, 1988, 1989).

4.2.3 Eshelby-Cheng model

There are two expansions for the Hudson model, first and second order (Hudson 1980, 1981, 1994).

For this study I investigated the second order expansion for dry cracks with the possibility in mind that this expansion might extend the theory to high crack densities. The mathematical formulation developed by Cheng solved the problem described in Hudson's model for higher crack densities.

The second order expansion was developed by Hudson (1980) for effective moduli for rocks with crack-induced anisotropy, and it predicts increasing moduli with higher fracture density (Cheng, 1993; Mavko et al., 2009).

The increase beyond the formal limit in crack density (Cheng, 1993) is attributed to the stiffness formulation used by Hudson (1981) for compliant cracks (Gueguen and Kachanov 2011).

The effective moduli C_{ij}^{eff} are given as:

C_{ij}^{eff} are the isotropic background and C_{ij}^1, C_{ij}^2 are first and second order corrections obey the usual symmetry properties for transverse isotropy which include five independent stiffness constants.

$$C_{ij}^{eff} = C_{ij}^0 + C_{ij}^1 + C_{ij}^2 \quad (4.14)$$

4.2.4 Assumptions and limitation, models Ruger Thomsen and Backus Averaging

Inversion aims to determine the characteristics of causal features by analyzing the effects these features produce. In geophysics, inverse problems generally aim to characterize some subsurface property, for example seismic wave velocity or density, by analyzing a set of observations where the desired parameter(s) induce some causal effect, for example a set of features present in seismic data. In this work, parameters that characterize fractures, namely fracture density and fracture orientation, are the desired earth parameters to be inverted. A 3D seismic dataset constitutes the set of observations that are to be analyzed to invert for these fracture characteristics. In any inverse problem, a proper understanding of the forward problem is crucial.

The forward problem specifies how changes in the desired model parameters alter certain observations. The forward problem allows one to generate synthetic data based on a certain set of parameters. The synthetic data is then compared to the real data.

The parameters associated with the synthetic dataset that most closely match the real data are considered to be the most likely parameters, i.e., the “answer” to the inverse problem. Depending on the problem, finding this set of “best-fit” parameters might be an iterative process. The forward

problems associated with the methods used in this work will be examined in detail in Chapters 4 and 5; however, in the interest of providing the theoretical framework for inversion, the following assumptions are necessary.

The Rüger method is based on the approximation on the Rüger AVO reflectivity in the HTI media (Rüger, 1997; Rüger and Tsvankin, 1997) in the equation addressed in Chapter 5 eq. 5.1. This equation is a modification of the two-term conventional AVO equation, shown in the Shuey Equation for normal AVO. With addition of an azimuthally varying gradient term (B_{ani}).

Variables A , B_{iso} and B_{ani} can be postulated in terms of elastic properties of the effective media generating the reflectivity (Rüger, 1997).

Rüger and Tsvankin (1997) conducted a thorough analysis showing that eq. 5.1 is an acceptable approximation to exact reflectivity in HTI media at relatively small incident angles (i.e., less than ~ 30 degrees) under the assumption of small jumps in reflectivity across the layer interface, arbitrarily weak anisotropy, and subcritical incident angles. Figure 4.6 shows for an evaluation of how Eq. 5.1 compares to exact expressions for reflectivity in isotropic, fluid filled fracture, and dry fracture end-cases.

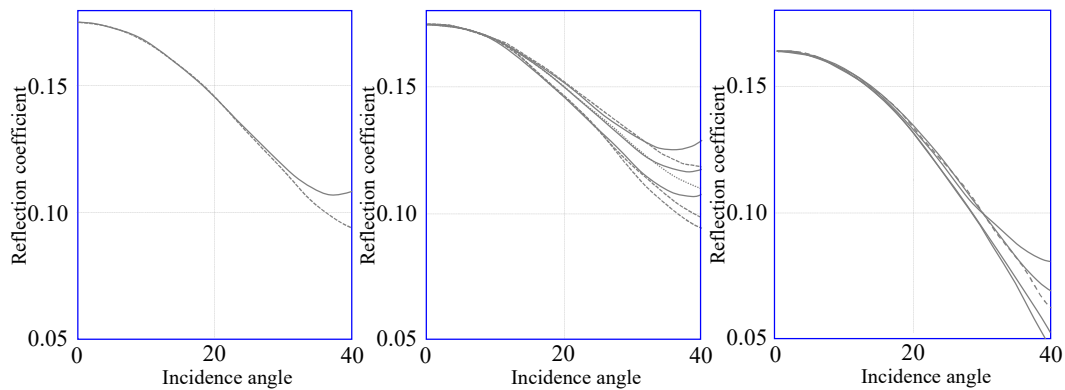


Figure 4.6 Comparison of exact and approximate reflectivity calculated using the Rüger AVO equation shown in eq 5.1. In all images the solid line represents exact reflectivity, and the dashed line represents approximated reflectivity. The leftmost image depicts the isotropic case. The middle image depicts the HTI case associated with fluid filled fractures. The rightmost image depicts the HTI case associated with dry fractures. The X axis represents incident angle, and the Y axis represents reflectivity.

Linearization of eq. (5.1) is performed using the method proposed by Xu and Li (2002), which utilizes trigonometric identities. In this context the Ruger Equation acts as a linear forward operator, and thus can be rewritten as:

$$\begin{pmatrix} R(\theta_1, \varphi_1) \\ R(\theta_2, \varphi_1) \\ \vdots \\ R(\theta_N, \varphi_1) \\ R(\theta_1, \varphi_2) \\ R(\theta_2, \varphi_2) \\ \vdots \\ R(\theta_N, \varphi_2) \\ \vdots \\ R(\theta_N, \varphi_n) \end{pmatrix} = \begin{pmatrix} 1 & \sin^2(\theta_1) & -\cos(2\varphi_1)\sin^2(\theta_1) & -\sin(2\varphi_1)\sin^2(\theta_1) \\ 1 & \sin^2(\theta_2) & -\cos(2\varphi_1)\sin^2(\theta_2) & -\sin(2\varphi_1)\sin^2(\theta_2) \\ \vdots & \vdots & \vdots & \vdots \\ 1 & \sin^2(\theta_N) & -\cos(2\varphi_1)\sin^2(\theta_N) & -\sin(2\varphi_1)\sin^2(\theta_N) \\ 1 & \sin^2(\theta_1) & -\cos(2\varphi_2)\sin^2(\theta_1) & -\sin(2\varphi_2)\sin^2(\theta_1) \\ 1 & \sin^2(\theta_2) & -\cos(2\varphi_2)\sin^2(\theta_2) & -\sin(2\varphi_2)\sin^2(\theta_2) \\ \vdots & \vdots & \vdots & \vdots \\ 1 & \sin^2(\theta_N) & -\cos(2\varphi_2)\sin^2(\theta_N) & -\sin(2\varphi_2)\sin^2(\theta_N) \\ \vdots & \vdots & \vdots & \vdots \\ 1 & \sin^2(\theta_N) & -\cos(2\varphi_n)\sin^2(\theta_N) & -\sin(2\varphi_n)\sin^2(\theta_N) \end{pmatrix} \begin{pmatrix} A \\ B \\ C \\ D \end{pmatrix} \quad (4.15)$$

where there are N incident angle bins, n azimuthal bins and $N * n$ data points at each location.

After matrices in Equation 4.15 have been populated with specific values corresponding to the azimuthal and incident angle binning scheme used in the analysis, data vector $\mathbf{m}$ can be solved using the standard least squares approach. This is repeated at every Common Depth Point (CDP) location and every time sample. After linearized coefficients A , B , C and D are found the coefficients are calculated shown in eq. (5.1), namely A , B_{iso} , B_{ani} and φ_{iso} .

φ_{iso} represents the azimuthal isotropy plane, and it is an indicator of fracture strike. Analysis of Equation 4.1 shows that at azimuth $\varphi = \varphi_{iso}$, reflectivity is at a local minimum with respect to azimuth. B_{ani} represents the magnitude of the azimuthal variation, and it is a direct indicator of fracture density. This agrees well with the intuitive notion that denser fracture spacing will result in a larger difference in seismic waves when compared to waves travelling parallel to those traveling

perpendicular to fracture strike. Note that seismic trace amplitude data was used in lieu of reflectivity because true impedances of the section are unknown.

Trace amplitude is roughly proportional to reflectivity, but this substitution limits inverted fracture density to be relative, rather than absolute. In general, the fracture number per unit length cannot be found, but areas of relatively high and relatively low fracture density can be identified. Unfortunately, substituting seismic amplitude for reflectivity is unavoidable in the analysis of real data.

Regrettably, the Rüger method presented above is fundamentally flawed. This comes largely from the linearization process used to make solving the problem computationally feasible. This leads to an inherent sign ambiguity in B_{ani} and thus an inherent inability to differentiate between the “fast” direction (parallel to φ_{iso}) and the “slow” direction (perpendicular to φ_{iso}).

The sign ambiguity in B_{ani} also indicates that the azimuth $\varphi = \varphi_{iso}$ could correspond to either a local maximum or a local minimum in seismic data with respect to azimuth. In practice, this sign ambiguity leads to an inherent 90-degree ambiguity in φ_{iso} , and thus an inherent 90-degree ambiguity in determining fracture azimuth. This 90-degree ambiguity can also be seen by examining equation, noting that $\tan(2\varphi_{iso})$ is 180 degrees periodic and thus will not be affected by any 90 degree change in φ_{iso} . This 90-degree ambiguity in fracture azimuth poses serious problems for well orientation planning and in effect makes the Rüger method unusable for determining fracture azimuth without further modification. Partially for this reason, an alternate HTI method was implemented which utilizes Fourier decomposition of the seismic data.

In the Thomsen fracture model, the HTI anisotropy (Figure 4.7) is assumed to be caused by parallel fracturing and where the reflectivity modeling assumes an overlying isotropic layer. This is considered reasonable for potential reservoirs with typically more homogeneous seal units above.

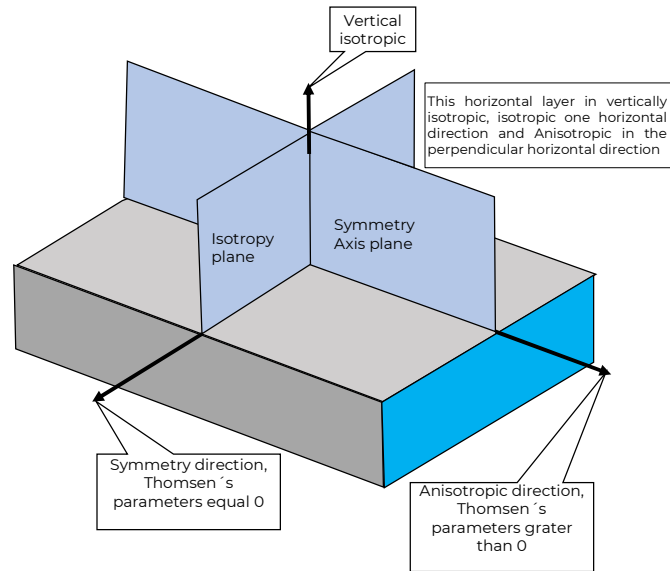


Figure 4.7 Thomsen's model fractured HTI anisotropy.

4.2.4.1 Thomsen model

Thomsen model

The theories of Hudson (1981) and Thomsen (1995) were designed for specific physical fracture models involving penny-shaped cracks and can be used to express Δ_N and Δ_T through parameters that are dependent on the microstructure of cracks and pores.

Although determination of these microstructural parameters from seismic data requires additional information about the medium, both Hudson's and Thomsen's models are helpful in guiding the interpretation of the weaknesses in terms of the crack density and fluid content. Vertical, parallel,

rotationally invariant fractures lead to a particular type of HTI media described by four independent parameters.

Thomsen-style anisotropic coefficients of HTI media $\varepsilon^{(V)}$, $\delta^{(V)}$, and $\gamma^{(V)}$ can be obtained in terms of the weaknesses Δ_N and Δ_T and the V_p/V_s ratio in the background medium. One of the anisotropic parameters ($\varepsilon^{(V)}$, $\delta^{(V)}$ or $\gamma^{(V)}$) can be found from the other two anisotropy parameters together with the V_p/V_s ratio.

$\varepsilon^{(V)}$, $\delta^{(V)}$, and $\gamma^{(V)}$ in any fracture induced HTI model are always negative, while the anellipticity parameter $\eta^{(V)}$ is predominantly positive.

All possible pairs $[\varepsilon^{(V)}, \delta^{(V)}]$ for HTI models resulting from parallel vertical fractures belong to a relatively narrow area with a quasi-triangular shape on the $[\varepsilon^{(V)}, \delta^{(V)}]$ -plane. These results can be used to identify fracture-induced HTI media from seismic measurements.

In the linearized weak-anisotropy approximation, all anisotropic parameters are proportional to the crack density, with the coefficients controlled by the V_s/V_p ratio and, for $\varepsilon^{(V)}$ and $\delta^{(V)}$, fluid saturation.

The shear-wave splitting parameter $|\gamma^{(V)}|$ for dry or fluid-filled cracks and a wide range of the V_s/V_p ratios remains close to the crack density. Therefore, the travel times or reflection amplitudes of split S-waves at vertical incidence are strongly dependent on the degree of fracturing but cannot be used to discriminate between dry and fluid-filled cracks.

4.2.4.2 Backus Average

Backus Average

The Backus average yields accurate replications of borehole acoustic logs that hinge on the formation elastic properties, wavelength and on the acoustic mode applied. Marion et.al. (1994), Liu and Schmitt (2006), and Mavko et al. (2009) propose that the transition from ray to effective medium theories for

ultrasonic waves propagating in a stack of horizontal layers occurs when the thickness of the layers is approximately 10 times smaller than the wavelength.

The Backus averaging method (1962) presents analytical expressions for equivalent elastic properties of a stack of thin layers. the individual layers may be isotropic, TIV, TIH, Orthorhombic, or monoclinic (Kumar, 2013). The Backus and Hudson (1980) models are, respectively, the common models used for upscaling and for crack induced anisotropy modeling. As stated by Saberi (2017) “Backus showed that at the long wavelength limit, a stratified medium composed of isotropic layers will behave like a transverse isotropic (TI) medium and derived the effective elastic constants for such a medium.

Hudson (1980) derived the effective elastic constants of a cracked medium by modeling an isotropic background superimposed with oriented cracks. This model is quite commonly used in carbonates for modeling fracture effects on velocities and modeling azimuthal inversion studies for fracture characterization.

Backus average is a methodology developed by Backus (1962) and is applied to finely layered medium to effect a transformation of this layered medium into a single homogeneous medium by upscaling the properties (Figure 4.8) This method has been used in the upscaling of well logs to seismic scale for velocity and density matches (Backus, 1962).

Typically, there are averaging techniques like blocking the density log where compressional and shear wave velocity logs have gradational tops and appear thicker, which may lead to a wrong result if overlooked. The advantage of sequential Backus averaging is that no artificial blocking is introduced in the geology during the upscaling of well-log data.

However, this method takes into consideration the following assumption based on Mavko et al., (2013).

- ✓ The thickness of layering must be much smaller than the seismic wavelength; the rule of thumb that wavelength must be ten times the layer thickness.
- ✓ No energy dissipation.
- ✓ All materials are linear elastic.

$$\begin{bmatrix} a & b & f & 0 & 0 & 0 \\ b & a & f & 0 & 0 & 0 \\ f & f & c & 0 & 0 & 0 \\ 0 & 0 & 0 & d & 0 & 0 \\ 0 & 0 & 0 & 0 & d & 0 \\ 0 & 0 & 0 & 0 & 0 & m \end{bmatrix} \quad (4.16)$$

The layers must be stacked with a new composite stiffness tensor:

$$\begin{bmatrix} A & B & F & 0 & 0 & 0 \\ B & A & F & 0 & 0 & 0 \\ F & F & C & 0 & 0 & 0 \\ 0 & 0 & 0 & D & 0 & 0 \\ 0 & 0 & 0 & 0 & D & 0 \\ 0 & 0 & 0 & 0 & 0 & M \end{bmatrix} \quad (4.17)$$

Where

$$C_{11} = A = \langle a - f^2 c^{-1} \rangle + \langle c^{-1} \rangle^{-1} \langle f c^{-1} \rangle^2 \quad (4.18)$$

$$C_{12} = B = \langle b - f^2 c^{-1} \rangle + \langle c^{-1} \rangle^{-1} \langle f c^{-1} \rangle^2 \quad (4.19)$$

$$C_{33} = C = \langle c^{-1} \rangle^{-1} \quad (4.20)$$

$$C_{44} = D = \langle d^{-1} \rangle^{-1} \quad (4.21)$$

$$C_{13} = F = \langle c^{-1} \rangle^{-1} \langle f c^{-1} \rangle^{-1} \quad (4.22)$$

$$C_{66} = M = \langle m \rangle \quad (4.23)$$

The volumetric proportion is denoted by using the brackets (Mavko et al., 2003). In the next example the M or C_{66} , which represents the shear modulus for a three-layer model is calculated as:

$$M = \frac{v_1 m_1 + v_2 m_2 + v_3 m_3}{v_1 + v_2 + v_3} \quad (4.24)$$

The volume term can be reduced to the thickness of each layer, as follow:

$$M = \frac{h_1 m_1 + h_2 m_2 + h_3 m_3}{h_1 + h_2 + h_3} \quad (4.25)$$

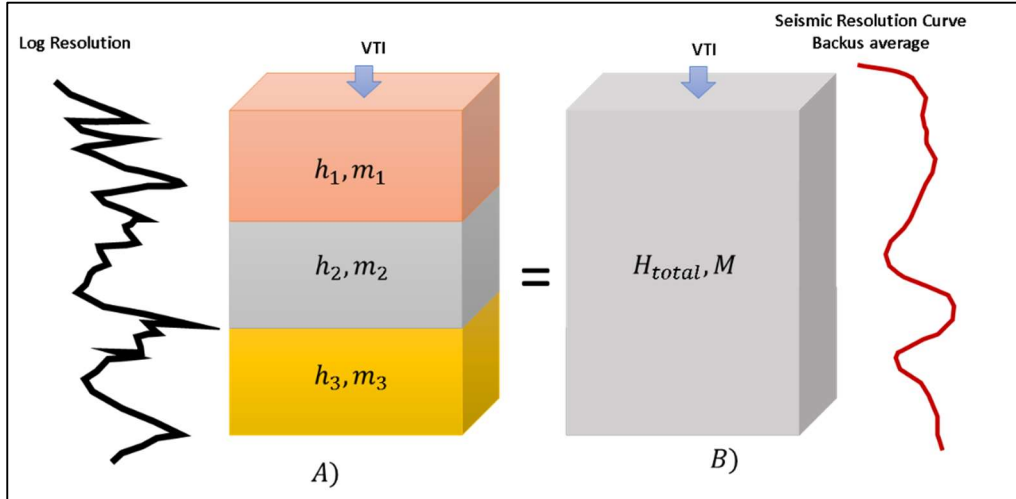


Figure 4.8. Backus averaging upscaling method; (A) represents model composed with three different stiffness tensors; (B) is the upscaled rock assuming only one effective stiffness tensor in VTI media.

4.2.5 Blocky Ops

Blocky models were completed in RokDoc software for all fracture models in both wells; parallel and orthogonal to the dominant fracture orientation derived from observations of the core photographs.

The operation in Blocky ops allows the estimation of the plane of the waves with normalised anisotropic velocities VTI and HTI, which measure the vertical propagation of waves orthogonal to the fractures.

For its calculation it is necessary to enter the values of Thomsen's parameters obtained in fractured models described in this chapter which comes from the log data in dry condition mentioned in each model (e.g., Hudson and Linear-Slip). This will be explained in the results section.

4.2.6 Fracture density B_{ani}

The anisotropy gradient related to fracture density can be estimated considering the AVO gradient for P-wave reflection from the interface isotropic and HTI model from earth model in Table 4.2. The difference between the AVO gradient orthogonal and parallel to fractures is known as B_{ani} can be estimated as follows (Rüger, 1997; Rüger and Tsvankin, 1997):

$$B_{ani} = \frac{\delta^{(V)} - 8g\gamma^{(V)}}{2} \quad (4.26)$$

This equation can be represented as function of fracture weaknesses as:

$$B_{ani} = g[\Delta_T - (1 - 2g)\Delta_N] \quad (4.27)$$

Assuming Penny-shaped cracks from Hudson's formulation the AVO gradient can be related to the crack density e , which leads to the following equation for dry fractures:

$$B_{ani}^{dry} = e \left[\left(\frac{4(-8g^2 + 12g - 3))}{(3(3 - 2g)(1 - g))} \right) \right] \quad (4.28)$$

4.3 Results

Based on the results of the seismic anisotropy obtained from the Hudson's and Schoenberg's models, the synthetic azimuthal seismic gathers from the wells Anhelido-1 and Serbal-1 are presented below for depths of 2113 m and 2908 m, respectively. These depths were selected for display of the results because both depths correspond to the mid unit of the Pimienta Formation and the landing zone of the horizontal wells since at this stratigraphic position, the TOC content is at its richest, between 2-5% in Anhelido-1 and 2-7% in Serbal-1. These values were obtained from the RockEval data and Passey's TOC log (see section 3.4) (Figure 3.17). The landing zone in both horizontal wells correspond to the maximum flooding surface of a third-order sequence as interpreted by PEMEX (Figure 4.9).

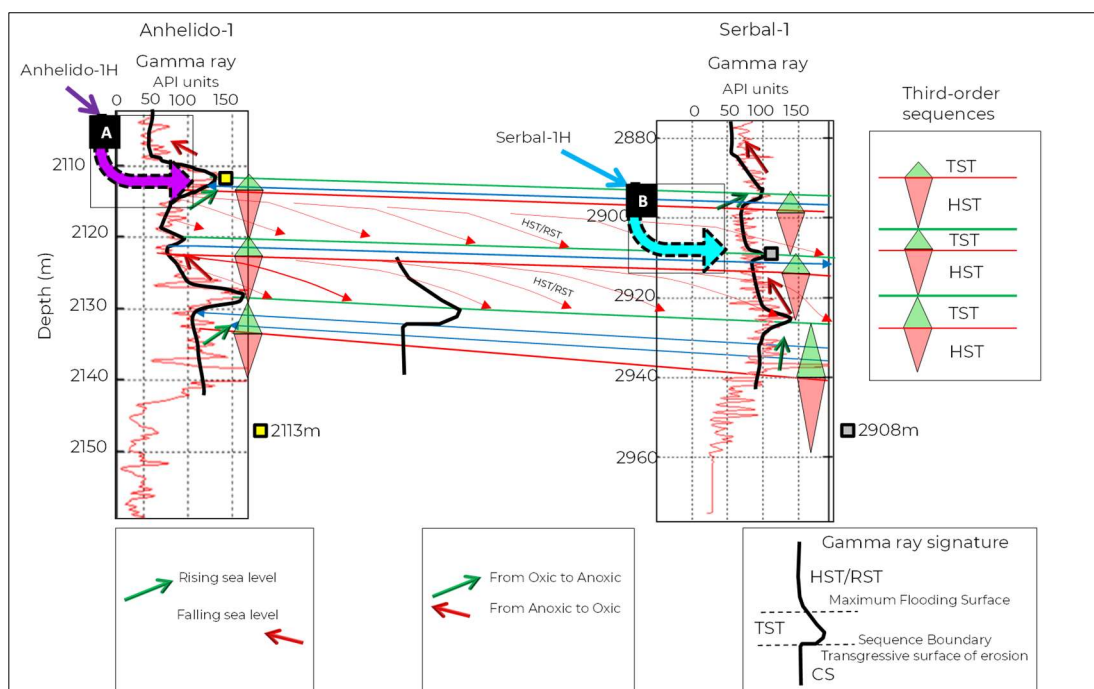


Figure 4.9 Third-order sequence stratigraphy model between vertical wells Anhelido-1 and Serbal-1; (A) Landing zone of the horizontal wellbore Anhelido-1H (magenta arrow) depth (2113m); (B) Landing zone of the horizontal wellbore Serbal-1H (light blue arrow) depth (2908m); According with Gamma ray signature Anhelido-1H and Serbal-1H landed in the spike of the mfs zone in the sequence model (modified from Slat and Rodriguez, 2010).

The modelling was undertaken using V_p , V_s , Density, the crack porosity e and the pore aspect ratio α , for the dry case. Seismic anisotropy induced by fractures computed using these three models shows azimuthal dependence that can be seen in the azimuthal display of the synthetic seismic gathers.

4.3.1 The Hudson Model

For the Hudson model, I based the aspect ratio and crack density using the rock properties available in the data set of the well Anhelido-1 where the aspect ratio is between 0.12 and This was 0.16. calculated from the well log data within the Pimienta Formation cross-plotted in a pore aspect ratio template from 0.05 – 1 (Figure 4.10 A) using porosity log and Bulk Modulus (DEM) logs the DEM analysis is addressed in Chapter 5 section 5.2.3.

Scanning electron microscope (SEM) photomicrographs were provided by PEMEX for relevant depth samples within the Pimienta Formation from Serbal-1 and from another well located 13 km to the south of Anhelido-1. The SEM image shows the aspect ratio more precisely and the pore aspect ratio can be inferred from these (Obtained from DEM Chapter 5 section 5.2.3). They are found to be Penny-shaped cracks in both wells that have been interpreted in this work. In Anhelido-1, these cracks fit best in the pore aspect ratio plot between 0.1-0.2 and in Serbal-1 between 0.04-0.16 (Figure 4.11 A).

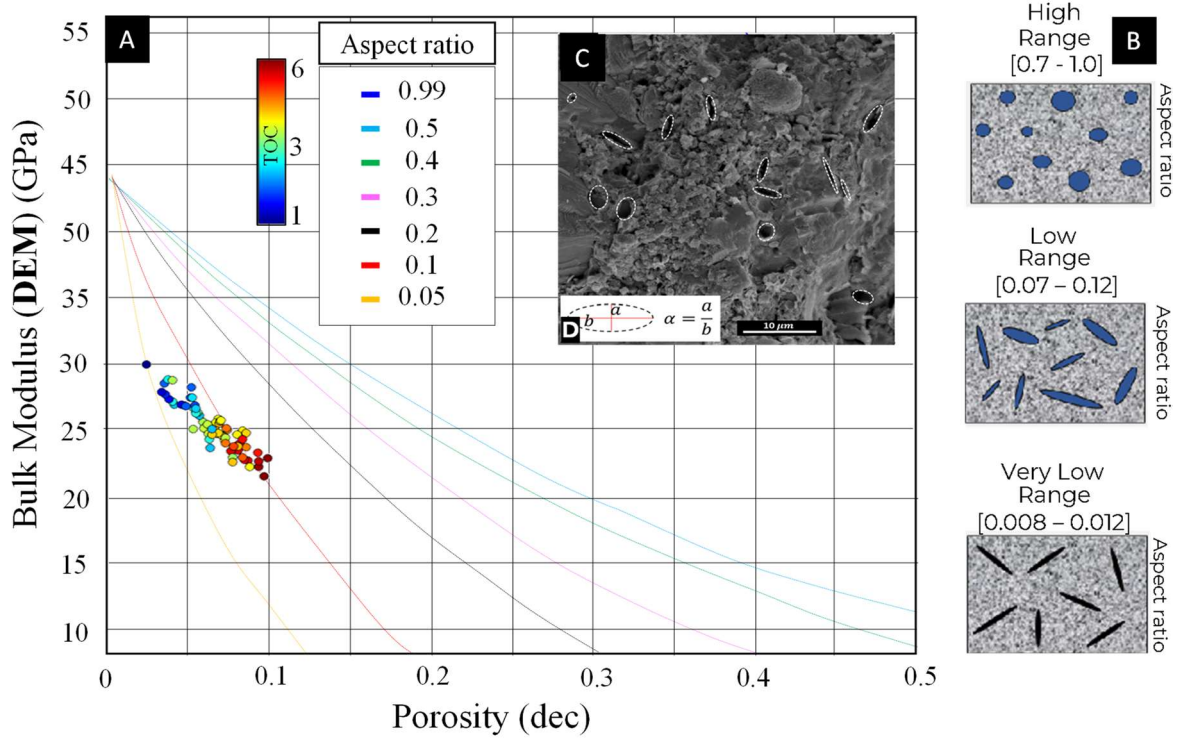


Figure 4.10 (A) Bulk modulus varying with porosity ϕ at Anhelido-1 showing the influence of pore aspect ratio in the Pimienta Formation with logging data (Porosity ϕ) overlapped the average value of aspect ratio between (0.1-0.2) approximately according with this graph; (B) Aspect ratio near to 1.0 increases Bulk modulus for a given porosity (Russell and Smith, 2007); (C) SEM photograph of a sample with ellipsoidal cracks of the mid unit of the Pimienta Formation in analogue well; (D) Graphical definition of pore aspect ratio.

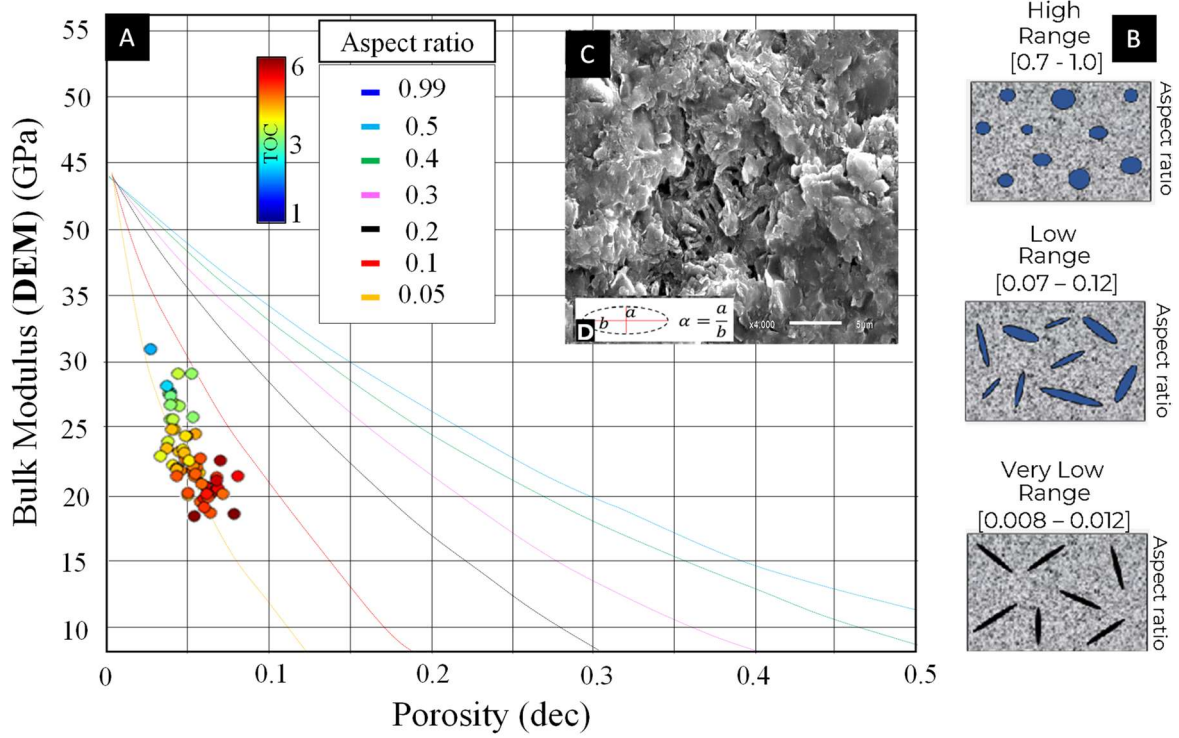


Figure 4.11 (A) Bulk modulus varying with porosity ϕ at Serbal-1 showing the influence of pore aspect ratio in the Pimienta Formation with logging data (Porosity ϕ) overlapping with the average value of aspect ratio between (0.04-0.16) approximately according with this graph; (B) Aspect ratio near to 1.0 increases P-wave velocity for a given porosity (Russell and Smith, 2007); (C) SEM photograph of a sample at Serbal-1 with ellipsoidal crack of the mid unit of Pimienta Formation; (D) Graphical definition of pore aspect ratio.

The methods I used to determine anisotropy were embodied in a code to compute the anisotropy parameters using the Hudson model from the Matlab RPHtools toolkit (Rock Physics handbook) (Mavko, 2000)

Assuming small cracks with a geometry of penny-shaped ellipsoidal inclusions and using an aspect ratio from the equations of Hudson (1980,1981), it is possible to consider the effective porosity values, velocities V_p , V_s , density, crack density e and aspect ratio α . This model requires these variables in order to calculate the anisotropic parameters.

For the numerical modelling of the Hudson Model, I have developed a Matlab script that combines multiple open-source codes (The code can be found in Appendix A.1). These codes include the fractured models described (e.g., Hudson and linear-slip) to make a display of the azimuthal changes in amplitude.

Using empirical relations from Han (1986) eq. (4.8), and eq. (4.9) where I obtained porosity values and clay content from log data within the Pimienta Formation to estimate the $V_p(dry)$ and $V_s(dry)$. The parameters below were used to compute the anisotropy values for the cracked model (Hudson Model).

Depth = 2013m Anhelido-1(Pimienta Formation)

Gives

$V_p(dry)(m/s) = 4742$
$V_p(dry)(m/s) = 3292$
$Rho(gr/cc) = 2.59$
$e = 0.03$
$\alpha = 0.1$
$Crack \phi = 0.03$
Effective $\phi = 0.06$

Anisotropic parameters

ϵ	γ	δ
-0.08	-0.04	-0.07

Depth = 2908 Serbal-1(Pimienta Formation)

Gives

Input data

$V_p(dry)(m/s) = 3877$
$V_p(dry)(m/s) = 2689$
$Rho(gr/cc) = 2.35$
$e = 0.04$
$\alpha = 0.1$
$Crack \phi = 0.023$
Effective $\phi = 0.05$

Anisotropic parameters

ϵ	γ	δ
-0.10	-0.05	-0.10

4.3.2 Schoenberg linear-slip model

In contrast, for the modelling in linear slip I also developed a Matlab code that estimate the induced anisotropy assuming planes of weakness infinitely extended and composed of five independent moduli constants (the code is presented in Appendix A.2). This model may be applicable in the Pimienta Formation because of the evidence in core photographs of fractures provided by PEMEX E&P for Anhelido-1 and Serbal-1 in Figure 4.2 A and Figure 4.3.

For Fractured Media (Linear-slip model)

Depth = 2013m Anhelido-1 (Pimienta Formation)

Gives

Input data	Anisotropic parameters		
$V_p (dry)(m/s) = 4742$	ϵ	γ	δ
$V_p (dry)(m/s) = 3292$	-0.01	-0.05	-0.13
$Rho(gr/cc) = 2.59$			
$Z_N = 0.034$			
$Z_T = 0.035$			

Where

Z_N , and Z_T are the normal and tangential compliances respectively. For dry inclusions the ratio $\frac{Z_N}{Z_T} =$

$(1 - \frac{\nu}{2})$. For fluid filled cracks the ratio goes to zero $\frac{Z_N}{Z_T} = 0$;

Depth = 2908m Serbal-1 (Pimienta Formation)

Gives

Input data
$V_p (dry)(m/s) = 3877$
$V_p (dry)(m/s) = 2689$
$Rho(gr/cc) = 2.35$
$Z_N = 0.056$
$Z_T = 0.058$

Anisotropic parameters		
ϵ	γ	δ
-0.02	-0.05	-0.11

4.3.3 Backus average

I used Matlab open-source RPHtools toolkit from the Rock Physics Handbook (Mavko et al., 2009) to estimate the average for V_p , V_s , and density to compute the stiffness matrix parameters in a generally homogeneous anisotropic medium that is equivalent to long-wavelength sampling of thin, stacked anisotropic layers. This method has been used in the upscaling of well logs to seismic scale for velocity and density matches (Backus, 1962)

The dominant frequency for both wells is 24Hz, as shown in Figure 4.12. The result is shown as the red curve as the upscaled property for each velocity curve, then the Thomsen's parameters are calculated using the upscaled velocities.

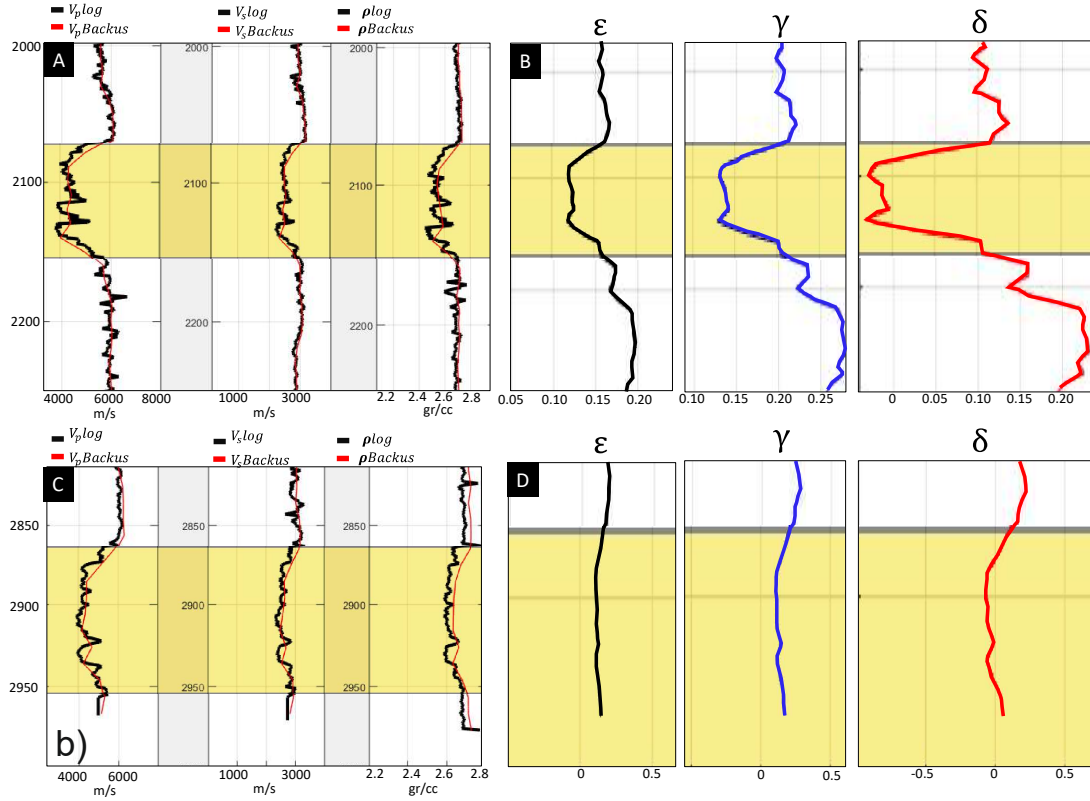


Figure 4.12 (A) Backus averaging upscaling V_p , V_s and density at Anhelido-1 within the Pimienta Formation. B) Thomsen's parameters from Backus average at Anhelido-1 within the Pimienta; (C) Backus averaging upscaling V_p , V_s and density at Serbal-1 within the Pimienta Formation. D) Thomsen's parameters from Backus average at Serbal-1 within the Pimienta Formation.

Based on the Backus average, the stiffness matrix was computed for both wells Anhelido-1 and Serbal-1 at depths of 2908m and 2113m, respectively shown in Table 4.2.

Well	Depth (m)	ϵ	γ	δ
Anhelido-1	2113	0.123	0.139	-0.011
Serbal-1	2908	0.112	0.118	-0.051

Table 4.2 Thomsen's parameters estimation using Backus averaging from well-log data.

4.3.3.1 Azimuthal synthetic seismic model in effective media

Modelling typically attempts to represent the rock properties of an earth-model through the seismic information (travel times and amplitudes) (Lines and Newrick, 2004).

To undertake this modelling procedure, I used the Thomsen's values obtained by each of the (e.g., Hudson and Linear Slip) in the Data and Methods Chapter 4.2. I developed a Graphical user interface (e.g., CRACKMED, FRACKMED) to obtain the anisotropy values and azimuthal synthetic model, based solely on the Velocity P, S, and densities in a dry case from Han's formulation explained in the data and methods of this chapter (Figure 4.13).

A

CRACKMED



CRACKED MEDIA
Hudson's Model

Vp(Dry) m/s

Vs(Dry) m/s

Rho(Dry) gr/cc

Crack Density (frac)

Aspect Ratio(frac)

Phie(frac)

Thomsen's parameters
as a function of Crack density

Result

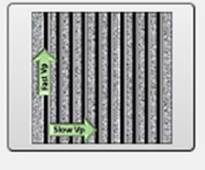
ϵ

γ

δ

B

FRACKMED



FRACTURED MEDIA
Linear-Slip Model

Vp(Dry) m/s

Vs(Dry) m/s

Rho(Dry) gr/cc

Compliances (1/GPa)

Z_N

Z_T

Result

ϵ

γ

δ

Figure 4.13. Graphical user Interfaces developed to compute the Thomsen's parameters using fractured models; (A) Hudson model; (B) Schoenberg Linear-slip model.

At Anhelido-1, I took the anisotropic values of each model from Table 4.1, and Table 4.2 at Serbal-1 as input values for the three effective medium models. In each model, the effect of anisotropy is better seen for far offset angles, so I selected the specific angle at 28° . Then I modelled the seismic gather azimuthally as a synthetic as well as the reflectivity through the azimuth, considering the full 360° range to undertake this process I developed a code called ModAz in MATLAB (the code is presented in Appendix A.3).

For the Hudson model at Anhelido-1 (Figure 4.14 A), it can be noted that in general, the reflection is negative within the Pimienta Formation. However, in the azimuth values of $\sim 100^\circ$ and 270° it can be observed that the reflectivity is more negative at these points. In contrast, Linear slip model shows similar response at the same azimuths ($\sim 100^\circ$ and 270°) (Figure 4.14 B) observed in Hudson model at these point the reflectivity is more negative.

For Serbal-1, the fractured models (e.g., Hudson and Linear Slip models) was completely different since the anisotropy was a bit more than Anhelido-1. The changes are seen in the same azimuths as the Anhelido-1 case. This confirms a higher percentage of anisotropy in this well, whereas in the Linear Slip model the effect of anisotropy is high as well (Figure 4.15 B). The last method was the Rüger-Thomsen, and for both wells the reflections were negative with minor changes, still with a certain percentage of anisotropy can be seen in Figure 4.15C.

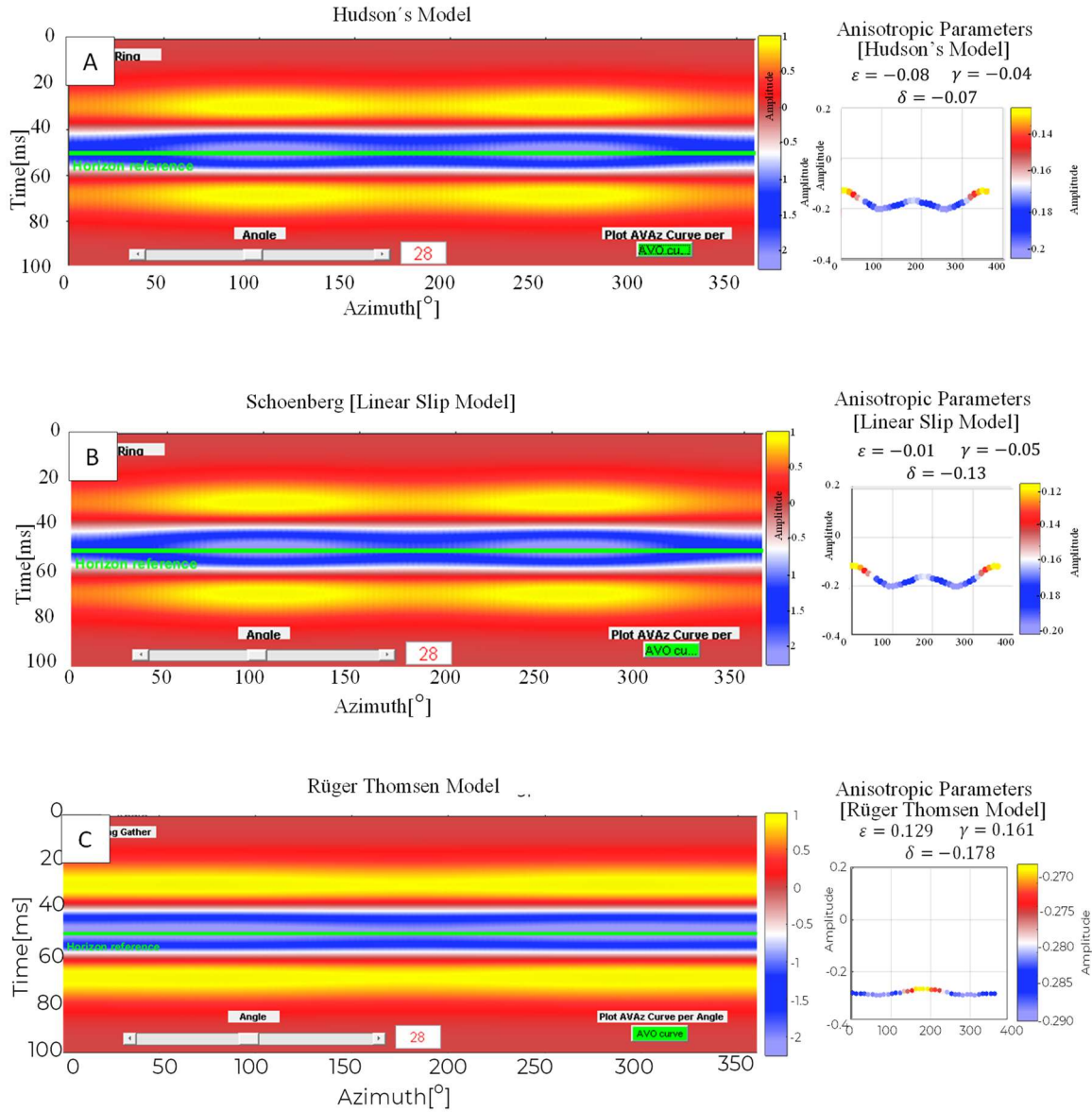


Figure 4.14. Fracture models from effective medium comparison and their anisotropic parameters differences at 28° angle incidence in the azimuthal synthetic gather at Anhelido-1. The green horizon line reference represents the top of Pimienta Formation for every model; (A) Hudson model azimuthal ring synthetic gather; (B) Linear-Slip model azimuthal ring synthetic gather- note an amplitude perturbation between (150° and 200°); (C) Rüger-Thomsen model - barely noticeable changes in amplitude distortions.

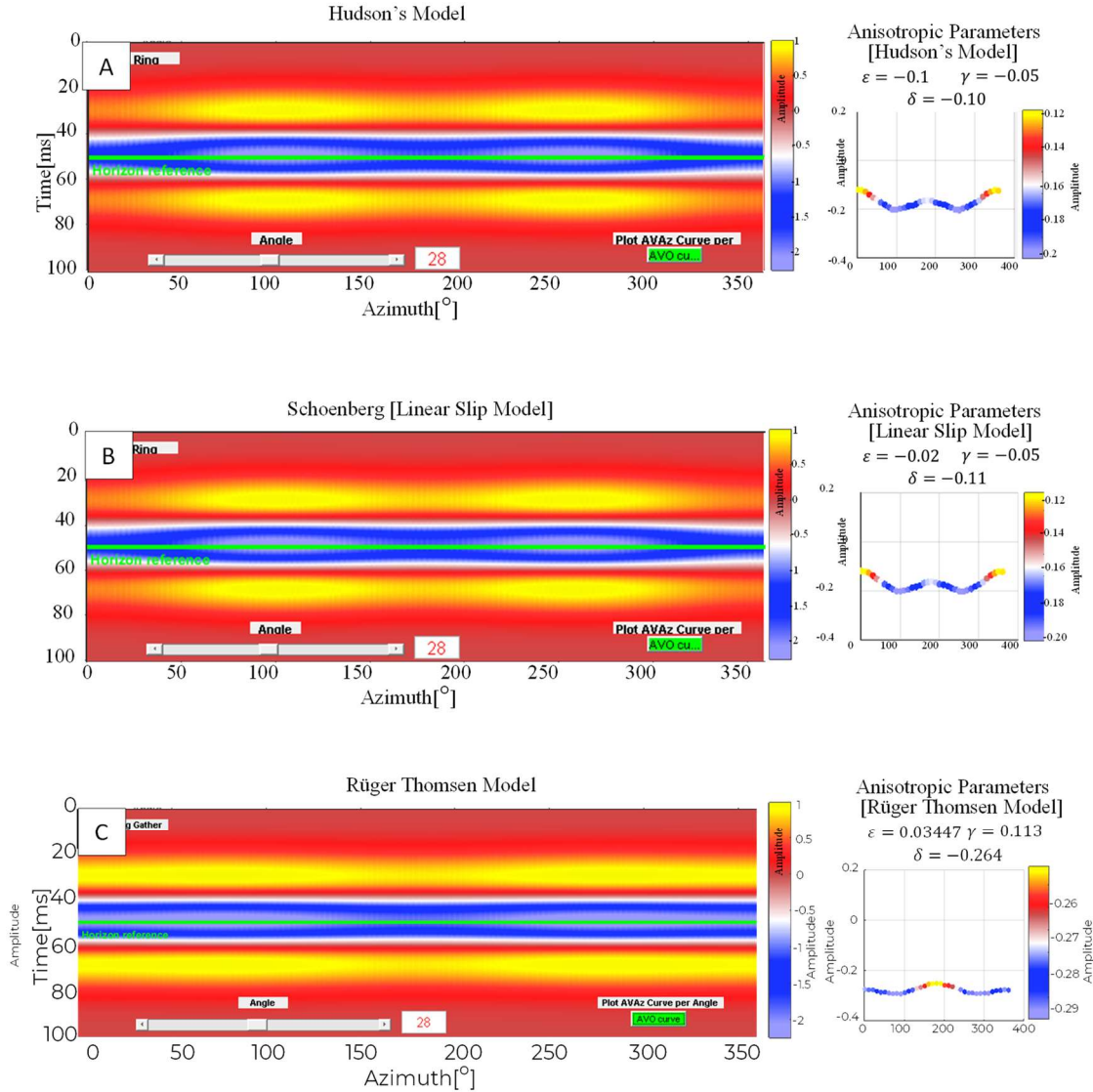


Figure 4.15. Fracture models from effective medium comparison and their anisotropic parameters differences at 28° angle incidence in the azimuthal synthetic gather at Serbal-1-1. The green horizon line reference represents the top of Pimienta Formation for every model; (A) Hudson model azimuthal shows changes in amplitude at ring synthetic gather between (150° and 200°); (B) Linear-Slip model azimuthal ring synthetic gather: note an amplitude perturbation between (150° and 200°); (C) Rüger-Thomsen model barely noticeable changes in amplitude distortions.

For angle incidence variation and the azimuthal full range from 0 -360°, modelling of synthetic gathers was carried out using the Linear Slip model. I used the anisotropic parameters with three values ($\varepsilon = -0.02$, $\gamma = -0.05$, $\delta = -0.11$) at Serbal-1 within the Pimienta Formation to investigate the impact of the amplitude variations on incidence angle and azimuth. This fracture model showed

a single most striking observation in terms of amplitude distortion to emerge from the data comparison for Anhelido-1.

The modelling was performed in a different ring gather using angle incidence variations (e.g., 8°, 28°, 43° and 55°) and full azimuth range (e.g., 0°- 360°). From the short review above, key findings emerge as the near incidence angle move away toward far angles and azimuth, the amplitude becomes more unstable. This may suggest that at far angles it is more likely to be able to see the effect of cracks or fractures in the modelling. In this case the amplitude distortions start to be evident at A 28° angle of incidence and a full range of azimuth. This angle of incidence was therefore taken to compute each fracture model (Figure 4.16).

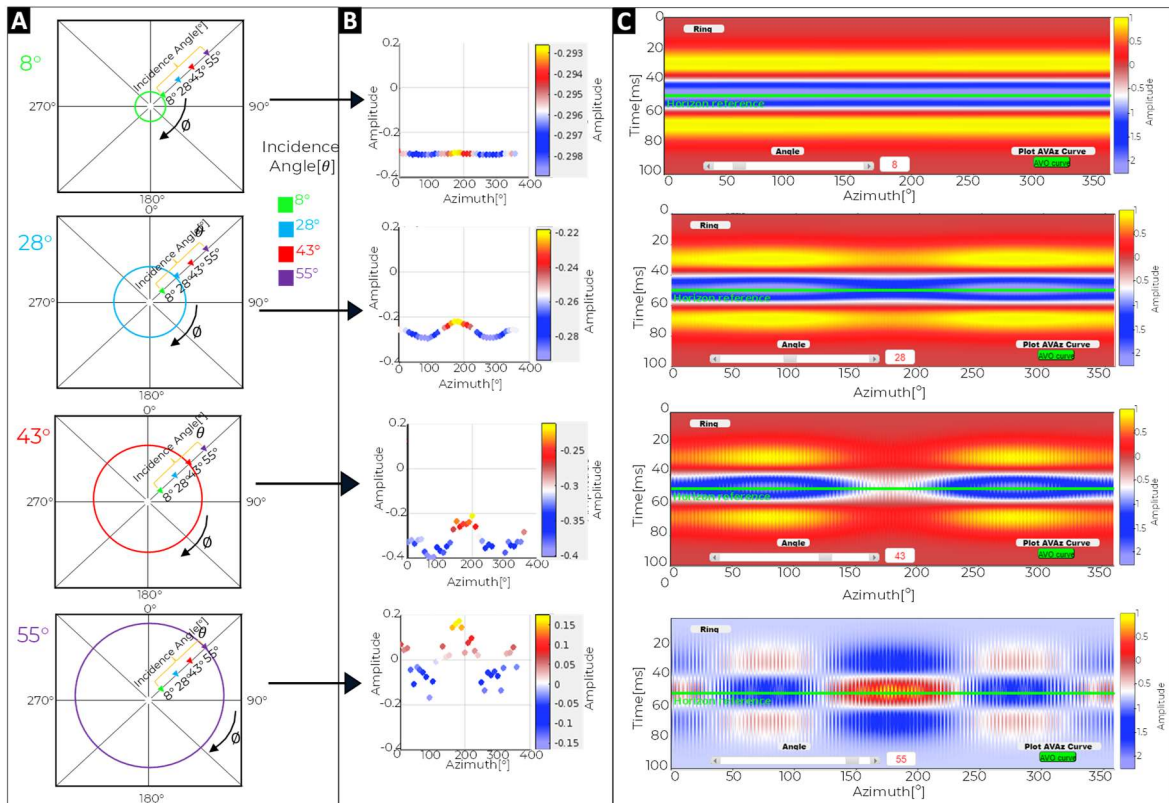


Figure 4.16 Synthetic azimuthal seismic gather modelling using Linear-slip fracture model at Serbal-1 within Pimienta formation; (A) Angle incidence “rings” (0°, 28°, 43°, and 55°) and azimuth full range (0° - 360°); (B) Reflectivity of angle incidence and azimuthal full range; (C) Azimuthal amplitude seismic gather of angle incidence and full azimuth.

4.3.4 Blocky Ops wave field and fracture density B_{ani}

Based on the fractured effective medium models it was possible to model the AVO curves and anisotropy response of R_{psv} , R_{psh} , and R_{ps-Iso} waves using Blocky Ops in RokDoc software that will be addressed in this section chapter and section 4.3.4.2. This operation was performed to analyse the reflectivity of the shear wave ellipses in polar view for far angles to see if the anisotropy is significant. For this, I used a three-layer model where the target was the shale model using the lithology of the project area. The model is shown in Table 4.3 for Anhelido-1 at depth of 2113 m and for Serbal-1 at a depth 2908m, these depths were chosen because both are within the mid unit of the Pimienta Formation and are richer in TOC content (see section 4.3)

For the model, the first layer is represented by an isotropic medium embedded in carbonate lithology with the velocity input data of P-Sonic, S-sonic and density. The second (target) layer, I assumed an HTI anisotropic medium with fractures using the dry case velocities for each well, and the third layer again representing an isotropic carbonate medium.

Anhelido-1	Layers	Medium Type	Lithology	Vp (m/s)	Vs (m/s)	Rho (gr/cc)
Depth: 2113 m	Layer 1	Isotropic	Carbonate	6020	3140	2.62
	Layer 2 (target)	HTI	Shale	4742	3292	2.59
	Layer 3	Isotropic	Carbonate	6000	3000	2.60
Serbal-1	Layers	Medium Type	Lithology	Vp (m/s)	Vs (m/s)	Rho (gr/cc)
Depth: 2908 m	Layer 1	Isotropic	Carbonate	6000	3000	2.62
	Layer 2 (target)	HTI	Shale	3877	2689	2.35
	Layer 3	Isotropic	Carbonate	6020	3140	2.60

Table 4.3 Earth model at Anhelido-1 depth: 2113 m and Serbal-1 depth: 2908m.

Based on this earth model above, I computed values of the fracture anisotropy, velocities, and densities for dry case in both wells as an azimuthal seismic gather at 28° of incidence angle from

fracture models (e.g., Hudson and Linear-slip). Differences in amplitude can be observed that are related to the anisotropic values in the target zone.

Fracture models were performed at the incidence angle of 28° , curves response in the AVO/AVA from Blocky Ops in RokDoc software package shows the anisotropic reflectivity of the elastic waves R_{psv} , R_{psh} , and R_{ps-Iso} which are perpendicular to the principal stress of the study area according with the stress map (section 4.3.4.1 Figure 4.22) in both wells Anhelido-1 and Serbal-1 (Figure 4.17 and Figure 4.18).

The P-wave particle displacement vector is perpendicular to its associated R_{ps-Iso} wavefront, whereas the wave travels purely horizontally, perpendicular to the plane of propagation and is parallel to stratal bedding. In contrast the R_{psv} is parallel to the plane of propagation and perpendicular to bedding.

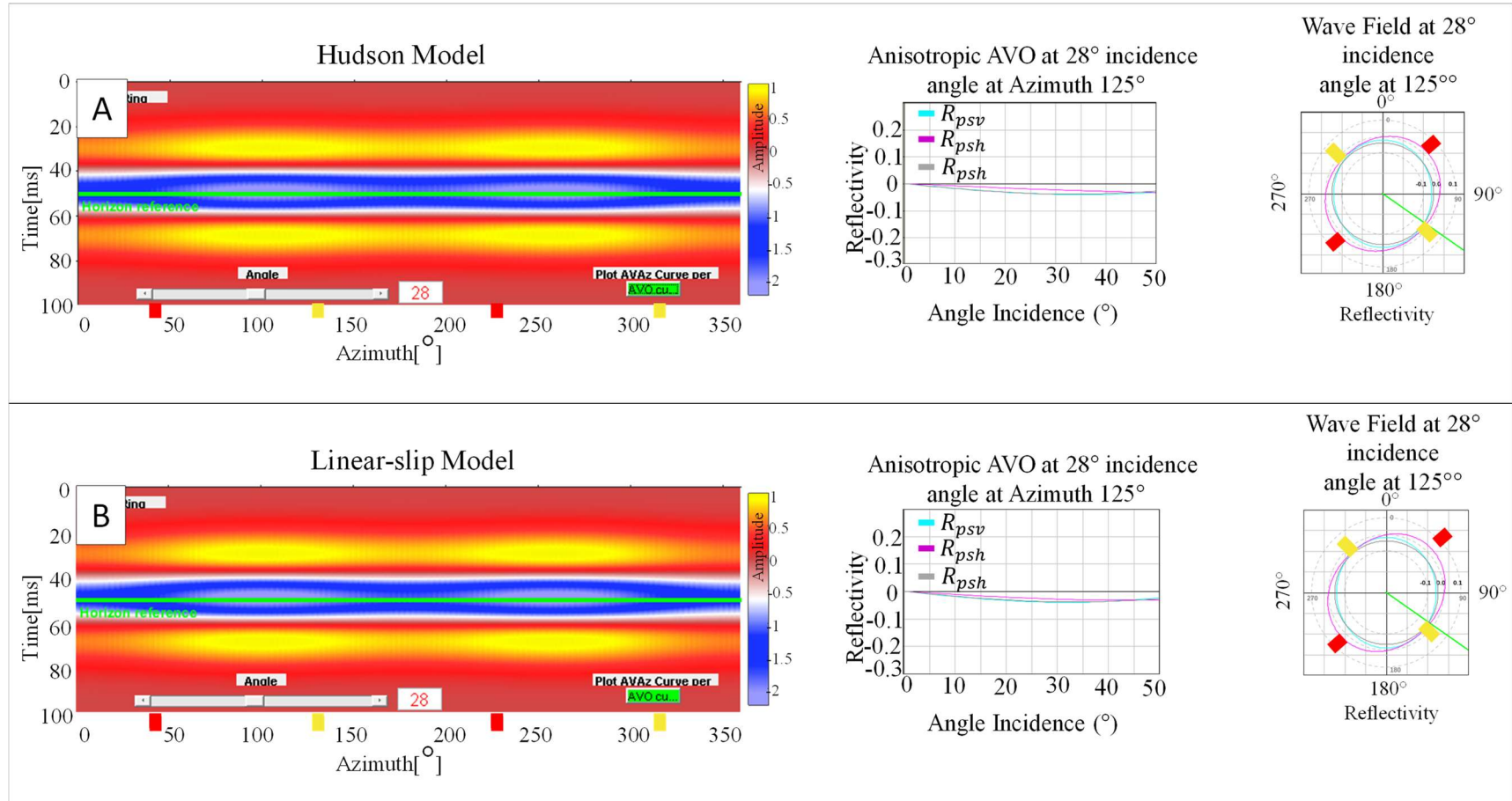


Figure 4.17. (A) Azimuthal synthetic gather for Hudson model and AVA curves at 28° angle incidence and azimuth 125° perpendicular to fractures based on project area information and polar view of wave field reflectivity (R_{psv} , R_{psl} , R_{psl}); (B) Azimuthal synthetic gather for Linear-slip model and AVA curves at 28° angle incidence and azimuth 125° perpendicular to fractures based on project area information and polar view of wave field reflectivity (R_{psv} , R_{psl} , R_{psl}) in Anhelido-1 within Pimienta Formation.

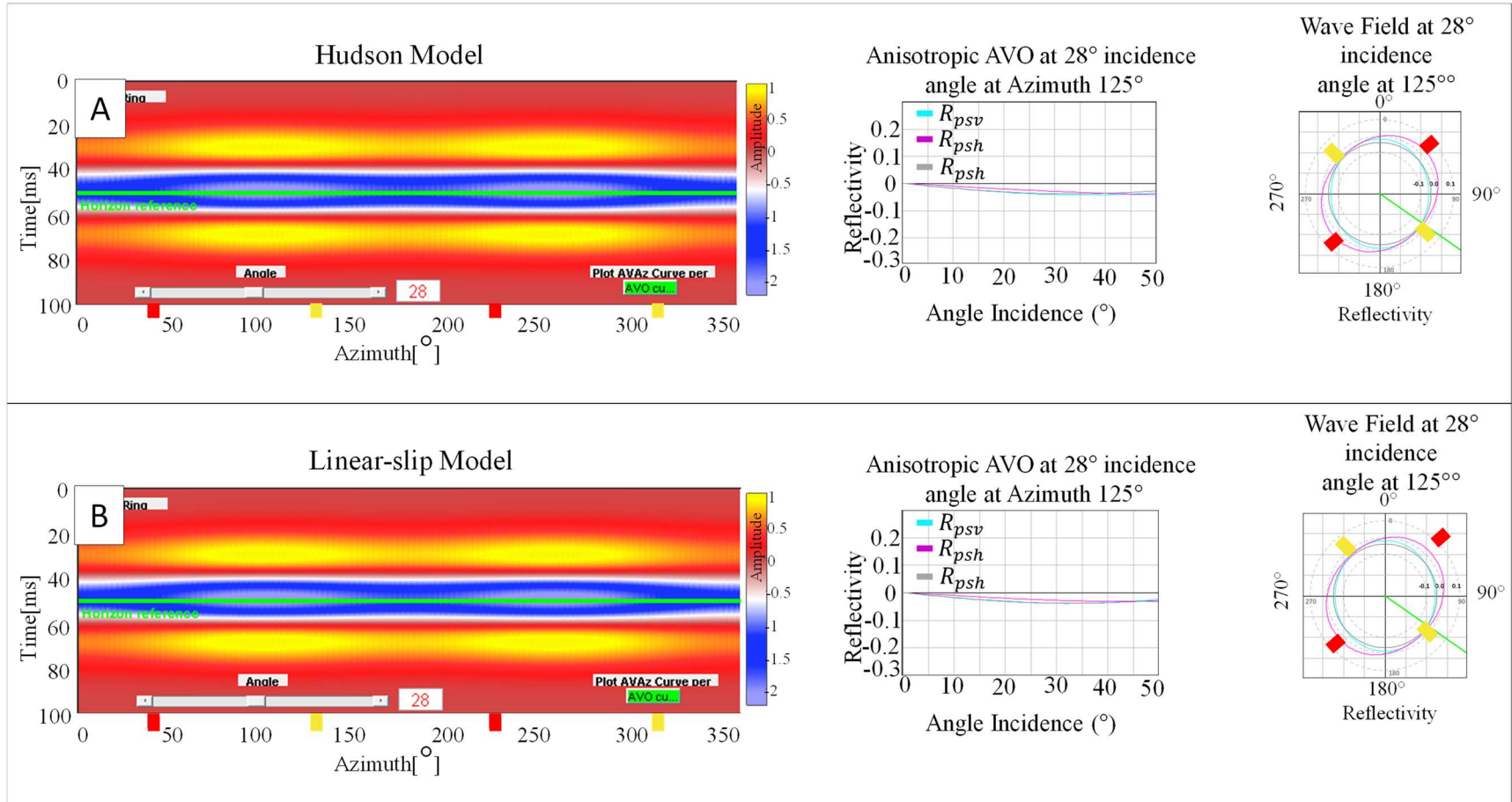


Figure 4.18. (A) Azimuthal synthetic gather for Hudson model and AVA curves at 28° angle incidence and azimuth 128° perpendicular to fractures based on project area information and polar view of wave field reflectivity (R_{psv} , R_{psl} , R_{psl} ,); (B) Azimuthal synthetic gather for Linear-slip model and AVA curves at 28° angle incidence and azimuth 128° perpendicular to fractures based on project area information and polar view of wave field reflectivity (R_{psv} , R_{psl} , R_{psl} ,) in Serbal-1 within Pimienta Formation.

The seismic signatures for HTI media using weakness values can be estimated from seismic data. For example, using the weak- anisotropy approximation for $\varepsilon^{(V)}$, $\gamma^{(V)}$, and $\delta^{(V)}$ the weaknesses can be obtained as follows:

$$\Delta_N = -\frac{\varepsilon^{(V)}}{2g(1-g)} \quad (4.29)$$

$$\Delta_T = \frac{1}{2g} \left[\left(\frac{(1-2g)}{(1-g)} \varepsilon^{(V)} \right) - \delta^{(V)} \right] \quad (4.30)$$

Where Δ_T is based on Pwave data which yield $\varepsilon^{(V)}$ and $\delta^{(V)}$ (Contreras et al., 1999), in the understanding that $g = \frac{V_s^2}{V_p^2}$ can be estimated using well-log data from the project area.

Using the same earth model from the (Table 4.3), the fractured density was estimated for every fractured effective medium model. I developed a graphical user interface called GUI in Matlab to compute the fracture density based on the anisotropic values assuming HTI in the target layer and VTI in the upper layer and the carbonate layer below the Pimienta Formation (the code can be found in Appendix A.5). For these VTI layers, I used the approximation of Thomsen's anisotropic parameters from Ryan-Grigor (1998) using log data.

The GUI computes B_{ani} using the model from Table 4.3 to estimate the anisotropic gradient based on the Thomsen's parameters from fracture models in order to see the differences which I called Baniz (Figure 4.19) (Appendix A.4). This interface uses the Rüger formulation to extract the B_{ani} from the azimuthal AVO equation. It uses the values of earth model based on the study area. For this modelling exercise of B_{ani} , the crack density value was set at $e = 0.03$, and the aspect ratio $\alpha = 0.1$ at Anhelido-1 and $e = 0.04$, and $\alpha = 0.1$ at Serbal-1 (Figure 4.20).

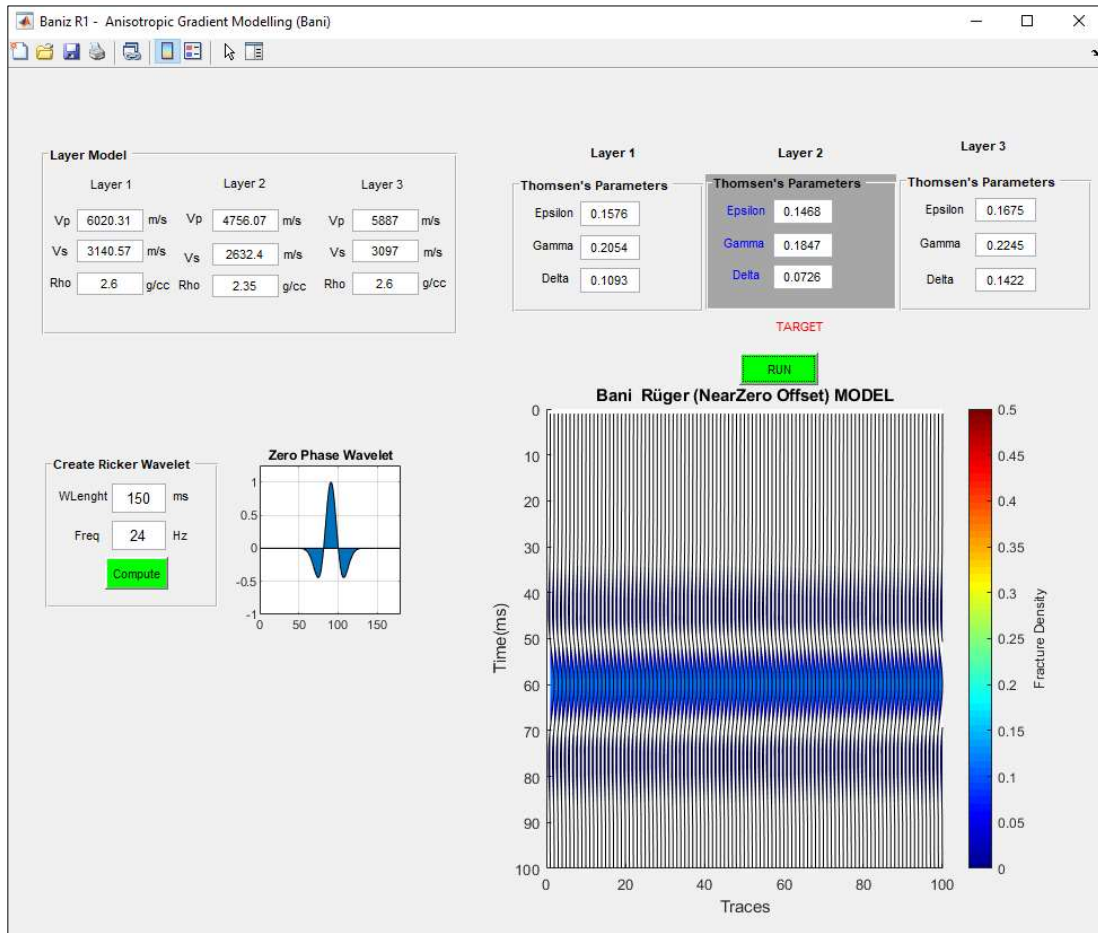


Figure 4.19. Baniz user interface to perform the modelling of anisotropic gradient related to fracture density.

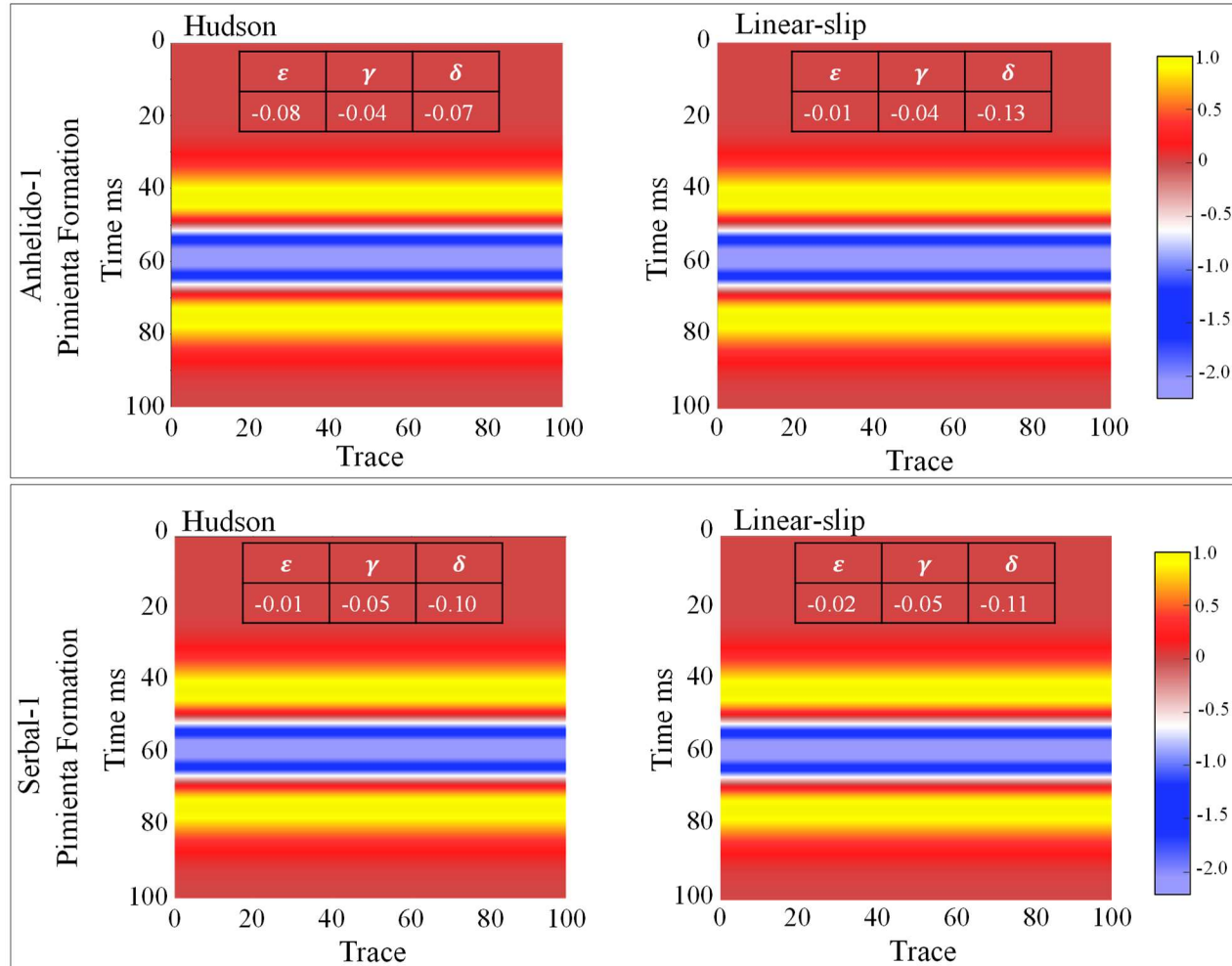


Figure 4.20 (A) Fracture density estimation using fracture models in terms of weak anisotropy from Thomsen's formulation as a function of crack density and weakness at Anhelido-1 within the Pimienta Formation; (B) Fracture density estimation using fracture models in terms of weak anisotropy from Thomsen's formulation as a function of crack density and weakness at Serbal-1 within the Pimienta Formation.

4.3.4.1 Fracture models comparison using Blangy model

To compare the reflectivity differences in angle gather I reproduced the response of AVA in horizontal transversely isotropic media in both wellbores. This operation was completed using the output values from fracture models so that it is possible to see the differences with respect to the isotropic case.

The results in Figure 4.21 show the application of 2-term (Blangy, 1994). This is the same as the Aki-Richard solution using the Agile geosciences library Python codes (Hall, 2014) which can handle anisotropic AVO. I modified this using the layer model for this study area (see Table 4.3) (the code can be found in Appendix A.6).

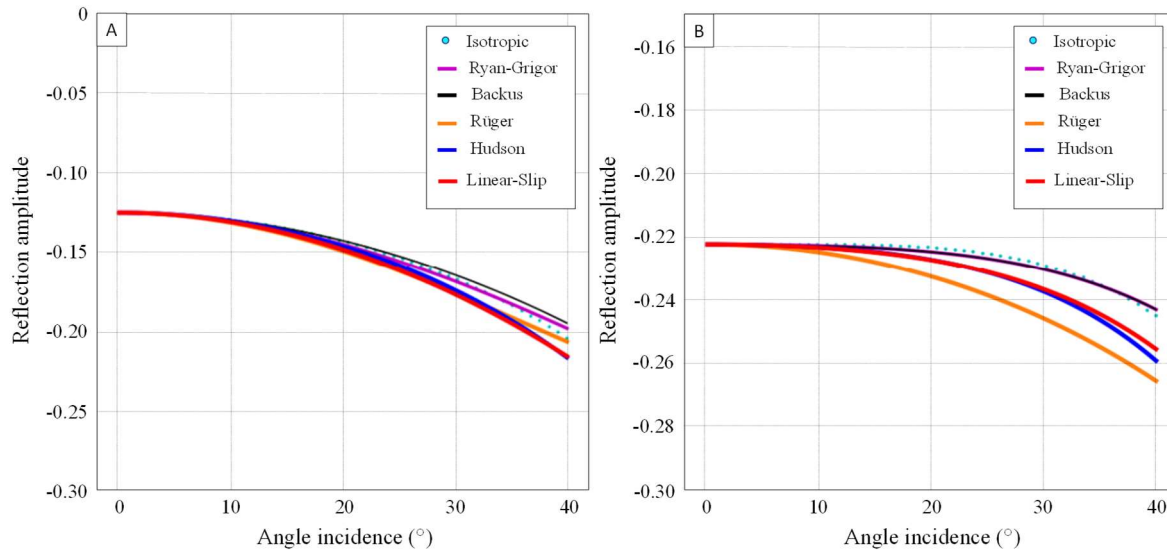


Figure 4.21 AVA models from an HTI shale within Upper Jurassic underlying a carbonate rock from lower Tamaulipas formation using Blangy solution (Blangy, 1994) for the anisotropic case using fracture models (Hudson 1981; Schoenberg 1980), the Backus average (Backus, 1962), Ryan-Grigor (Ryan-Grigor, 1994) and Rüger approximations (Rüger, 1996, Rüger, 1997, Rüger, 1998). The dashed line represents the isotropic case.

4.3.4.2 Blocky Model for HTI reflectivity from fracture models

A blocky model was performed using a shale layer (assumed HTI) over a carbonate layer (considered isotropic) to graph the PP wave for both the isotropic and anisotropic cases.

The AVO curves for HTI anisotropy were obtained for the reflectivity of waves R_{psv} , R_{ps} , and R_{ps-Is} , using the Hudson, Linear-Slip models.

The average angle between SHmax, Shmin and fracture from stress map of the project area is roughly 45° (Heidbach et al., 2016) (Figure 4.22). The anisotropic AVA plots of fracture models (e.g., Hudson and Linear-slip) were analysed in different azimuths.

A difference in AVO/AVA reflectivity may be observed when waves travel parallel to the SHmax and fracture. The R_{psh} wave is elongated at the observation in the azimuth 52° (Figure 4.23 A), and from this we infer that the wave travels fast.

In contrast, when the R_{psh} is orthogonal to the SHmax and fracture, the wave behaviour changes in negative reflectivity AVA curves (114°- 125° azimuth) and might suggest that wave travel slow as can be seen in Figure 4.23 B.

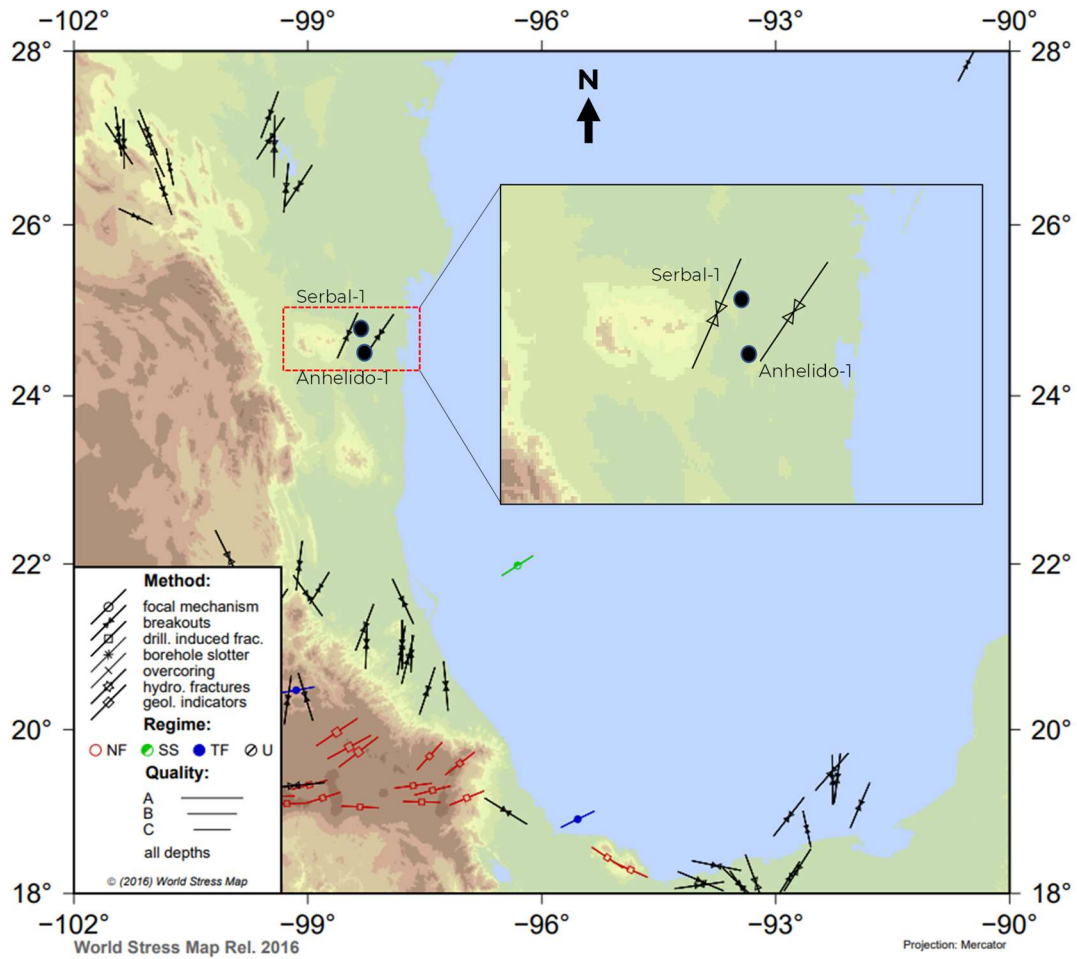


Figure 4.22 (A) World stress map Rel. 2016 of present stress field within the study area; (B) Close-up of study area with the stress orientation of the S_{hmax} (Heidbach et al., 2016) based on borehole breakout information.

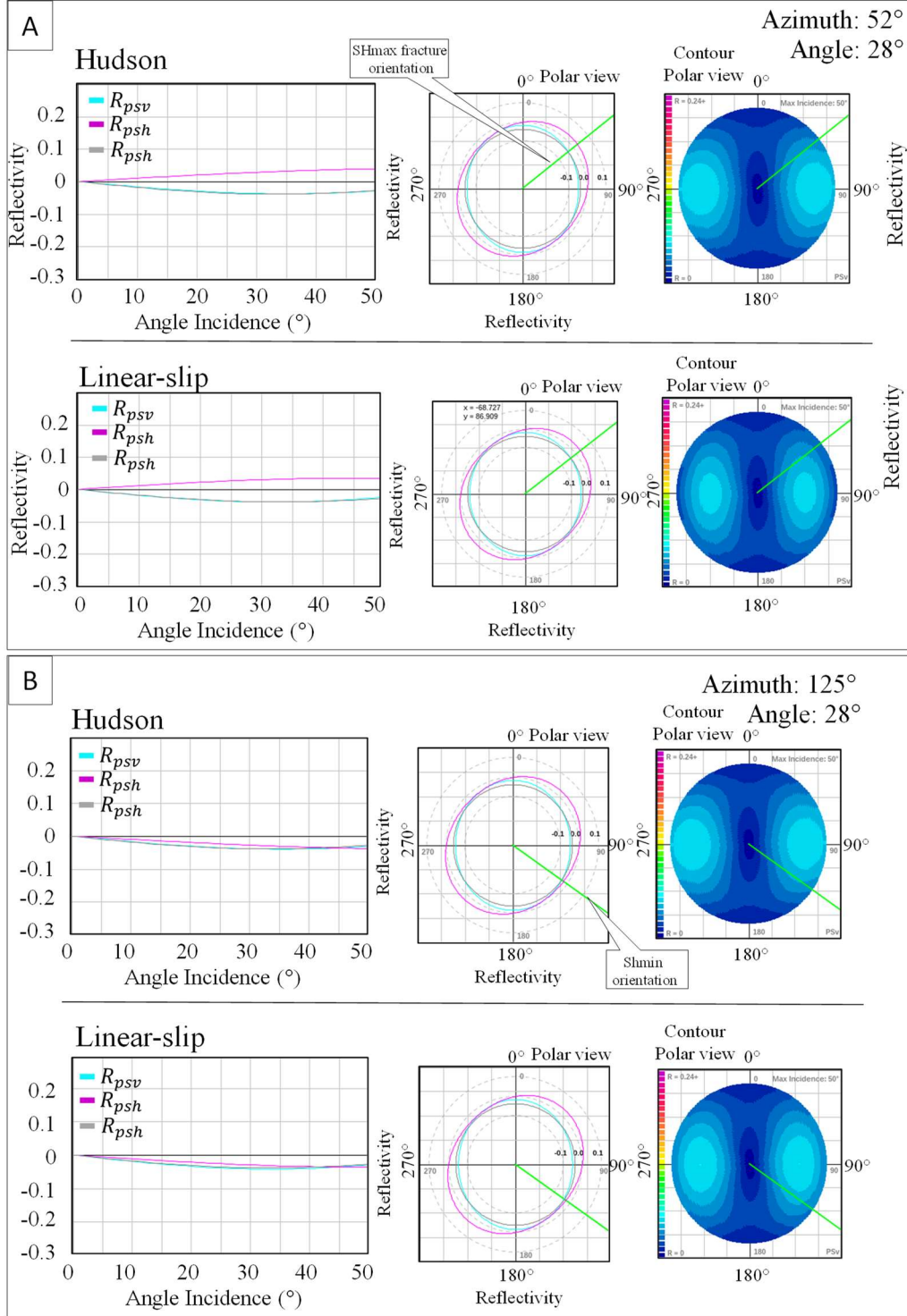


Figure 4.23 (A) Blocky models using the fracture models (Hudson and Linear-slip) parallel to stress SHmax and fractures, AVO curves of wave field R_{psv} , R_{ps} , and R_{ps-l} and its polar view, green line represent stress-fracture direction in azimuth according with the stress map (52° and 66°); (B) Blocky models using the fracture models (Hudson and Linear-slip) perpendicular to stress SHmax and fractures, AVO curves of wave field R_{psv} , R_{ps} , and R_{ps-l} and its polar view, green line represent Shmin direction in azimuth (114° and 125°).

The anisotropic phase velocity for the Pimienta Formation has thus far been obtained in both vertical transverse isotropy (VTI) and horizontal transverse isotropy (HTI) for the velocity of the waves R_{psv} , R_{psh} , and R_{ps-Iso} in (Blocky Ops) using the RokDoc software.

In the Figures, 4.24 and 4.25 at Anhelido-1 (2113 m depth) and in the Figures 4.26 and 4.27 at Serbal-1 (2908 m depth) the propagation for the R_{psv} , R_{psh} , and R_{ps-I} reflectivity waves are displayed assuming VTI and HTI medium within the Pimienta Formation. For this purpose, I used the values corresponding to Hudson and Linear-slip models in both wells as input data in RokDoc software which has a module that can perform these calculations.

The anisotropic values were:

Thomsen's parameters from Hudson: $\varepsilon = -0.26$, $\gamma = -0.12$, $\delta = -0.26$ and the velocities for dry case

$$(v_p = 4242 \text{ m/s } v_s = 3292 \text{ m/s}).$$

Linear-slip: $\varepsilon = -0.071$, $\gamma = -0.13$, $\delta = -0.25$ and the velocities for dry case

$$(v_p = 4242 \text{ m/s } v_s = 3292 \text{ m/s}).$$

For Hudson's Model:

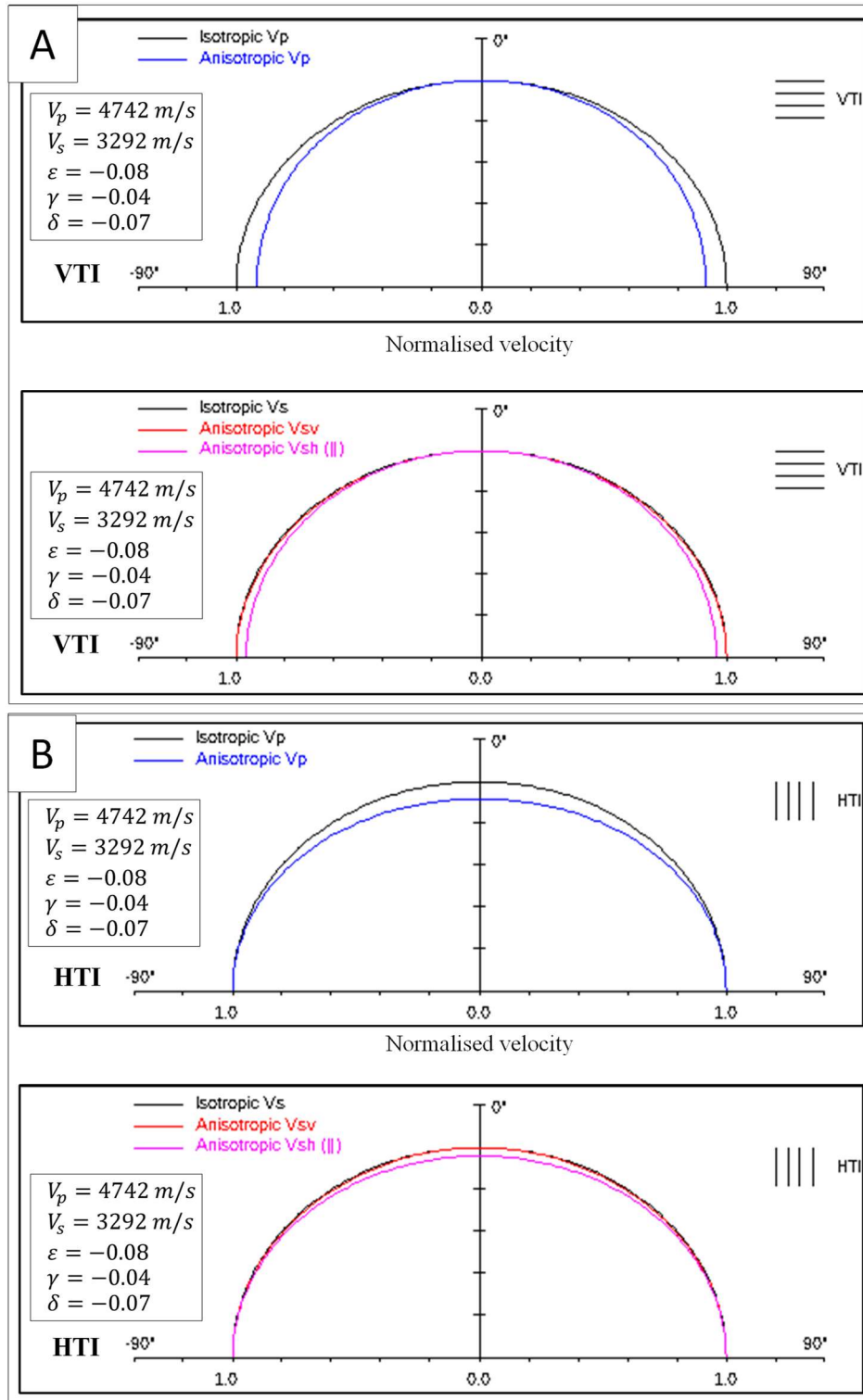


Figure 4.24 (A) Anisotropic wave propagation for given anisotropic parameters in VTI mode within the Pimienta Formation at Anhelido-1 using Hudson's Model; (B) Anisotropic wave propagation for given anisotropic parameters in HTI mode within the Pimienta Formation at Anhelido-1 using Hudson's Model.

Linear-slip gives

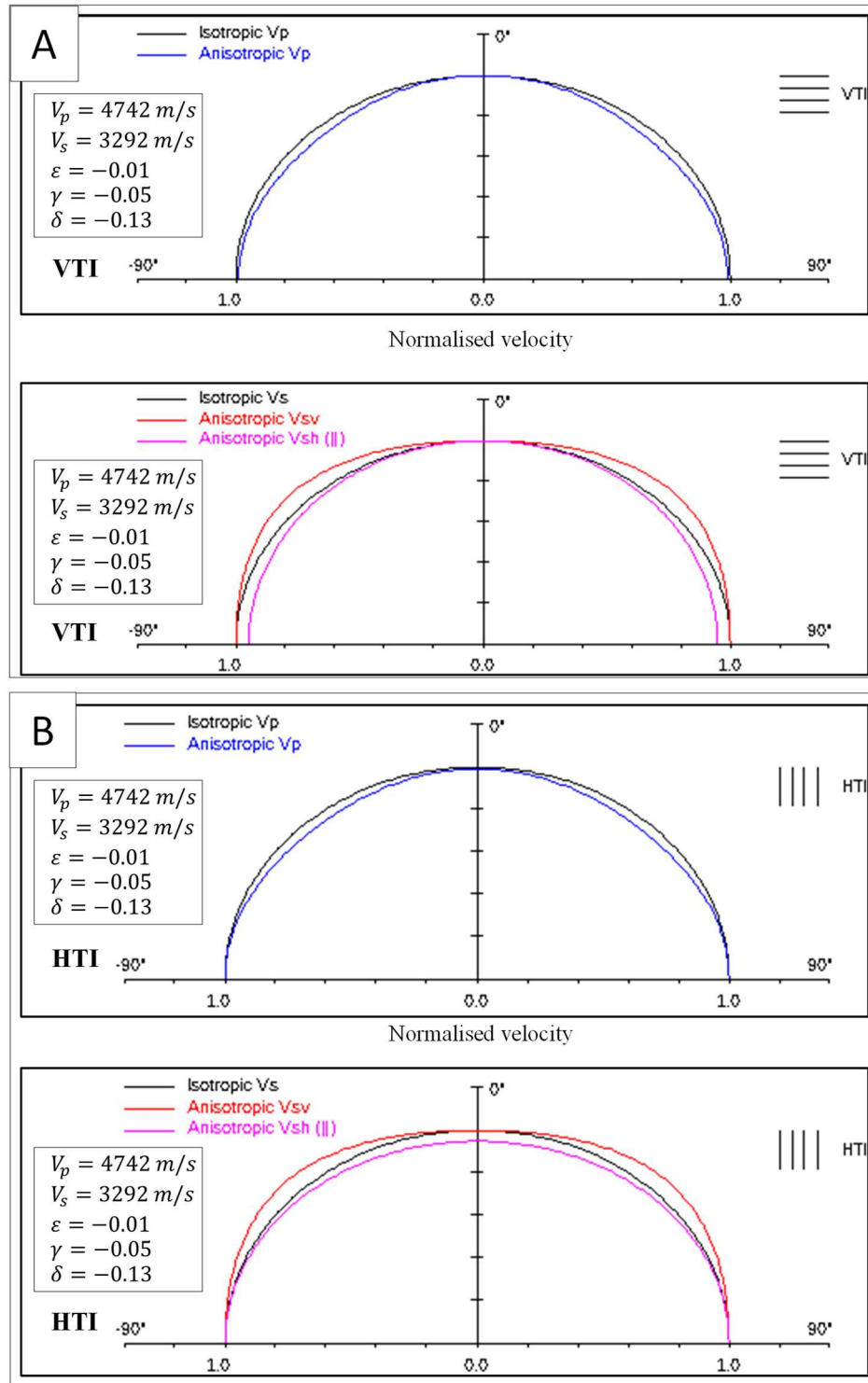


Figure 4.25 (A) Anisotropic wave propagation for given anisotropic parameters in VTI mode within the Pimienta Formation at Anhelido-1 using Linear-slip Model; (B) Anisotropic wave propagation for given anisotropic parameters in HTI mode within the Pimienta Formation at Anhelido-1 using Linear-slip model.

In Serbal-1 the anisotropic values were:

Hudson: $\varepsilon = -0.69, \gamma = -0.34, \delta = -0.69$ and the velocities for dry case

$$(v_p = 3877 \text{ m/s } v_s = 2689 \text{ m/s}).$$

Linear-slip: $\varepsilon = -0.18, \gamma = -0.34, \delta = -0.66$ and the velocities for dry case

$$(v_p = 3877 \text{ m/s } v_s = 2689 \text{ m/s}).$$

Serbal-1 depth:2908m Phase velocity plots

For Hudson Model gives:

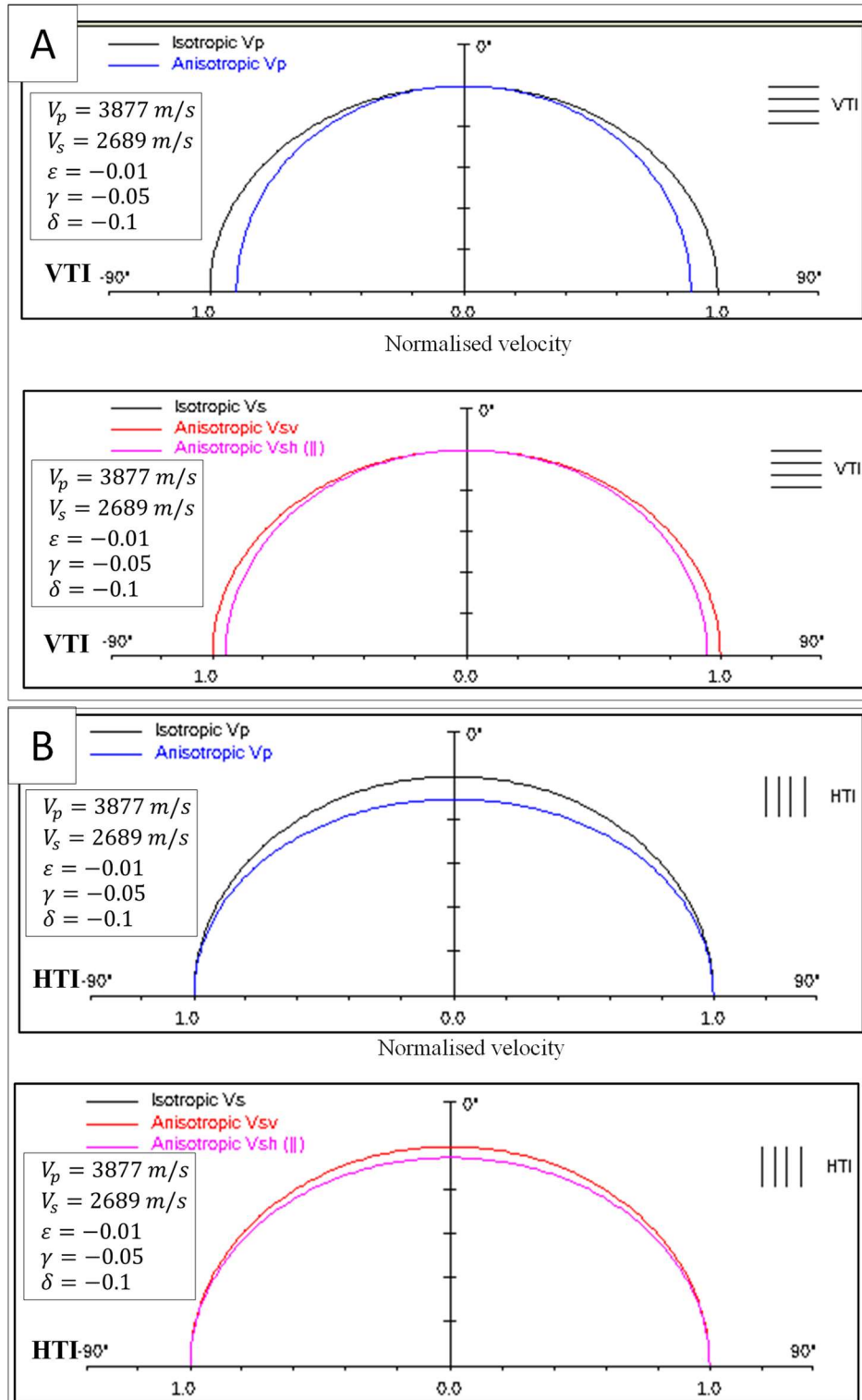


Figure 4.26 (A) Anisotropic wave propagation for given anisotropic parameters in VTI mode within the Pimienta Formation at Serbal-1 using Hudson's Model; (B) Anisotropic wave propagation for given anisotropic parameters in HTI mode within the Pimienta Formation at Serbal-1 using Hudson's Model.

For Linear-slip model gives:

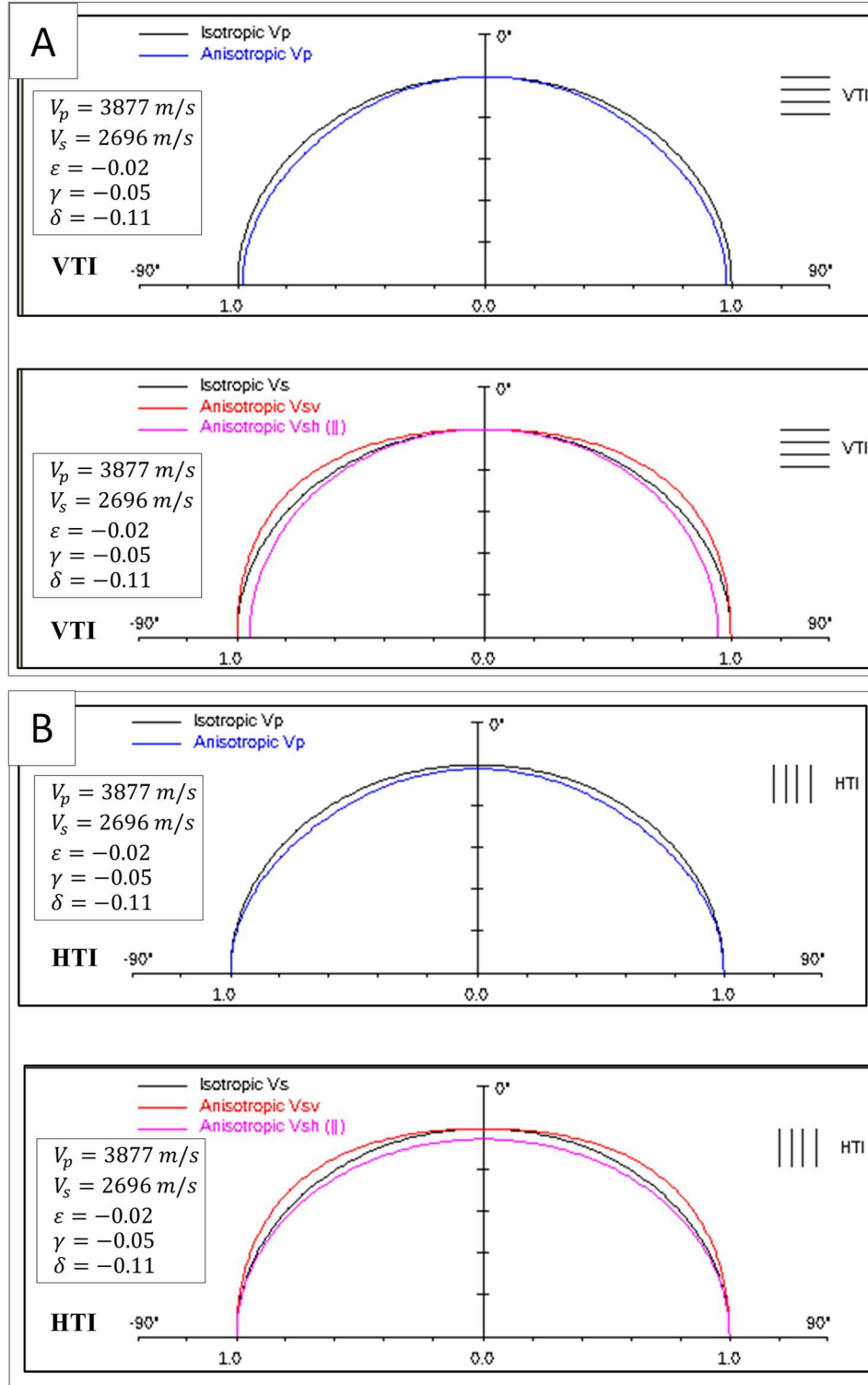


Figure 4.27 (A) Anisotropic wave propagation for given anisotropic parameters in VTI mode within the Pimienta Formation at Serbal-1 using Linear-slip Model; (B) Anisotropic wave propagation for given anisotropic parameters in HTI mode within the Pimienta Formation at Serbal-1 using Linear-slip model.

4.3.4.3 Effect of Fracture density and aspect ratio

To see the effect of fracture models with the anisotropic Thomsen's parameters, I estimated the variations in the crack density and the pore aspect ratio values. These resulted in remarkable differences in the anisotropy parameters outputs. These variations can be seen for Anhelido-1 and Serbal-1 (Tables 4.4 and 4.5) using the velocities P, S, and densities of the dry case previously mentioned in the section dealing with wave propagation models (see section 4.3.4.2).

Fracture Model	Velocity/Density (dry)	Crack Density ϵ and aspect ratio α (Anisotropic parameters)		
		$\epsilon=0.04$	$\epsilon=0.1$	$\epsilon=0.15$
		$\text{asp}=0.1$	$\text{asp}=0.1$	$\text{asp}=0.5$
Hudson	$V_p = 4742$	$\epsilon=-0.10$	$\epsilon=-0.26$	$\epsilon=-0.40$
	$V_s = 3292$	$\gamma=-0.05$	$\gamma=-0.13$	$\gamma=-0.20$
	$\rho=2.59$	$\delta=-0.10$	$\delta=-0.26$	$\delta=-0.40$
	$\text{Frac}\phi = 0.023$			
Linear-Slip	$V_p = 4742$	$\epsilon=-0.02$	$\epsilon=-0.07$	$\epsilon=-0.10$
	$V_s = 3292$	$\gamma=-0.05$	$\gamma=-0.13$	$\gamma=-0.19$
	$\rho=2.59$	$\delta=-0.10$	$\delta=-0.25$	$\delta=-0.38$
	$Z_N = 0.034$			
	$Z_T = 0.035$			

Table 4.4. Observations of the crack density effect and aspect ratio on anisotropic parameters at Anhelido-1 within Pimienta Formation.

Fracture Model	Velocity/Density (dry)	Crack Density ϵ and aspect ratio α (Anisotropic parameters)		
		$\epsilon=0.04$	$\epsilon=0.1$	$\epsilon=0.15$
		$\text{asp}=0.1$	$\text{asp}=0.1$	$\text{asp}=0.5$
Hudson	$V_p = 3877$	$\epsilon=-0.10$	$\epsilon=-0.26$	$\epsilon=-0.40$
	$V_s = 2689$	$\gamma=-0.05$	$\gamma=-0.13$	$\gamma=-0.19$
	$\rho=2.59$	$\delta=-0.10$	$\delta=-0.26$	$\delta=-0.40$
	$\text{Frac}\phi = 0.023$			
Linear-Slip	$V_p = 3877$	$\epsilon=-0.028$	$\epsilon=-0.071$	$\epsilon=-0.10$
	$V_s = 2689$	$\gamma=-0.05$	$\gamma=-0.13$	$\gamma=-0.19$
	$\rho=2.35$	$\delta=-0.10$	$\delta=-0.25$	$\delta=-0.38$
	$Z_N = 0.056$			
	$Z_T = 0.058$			

Table 4.5. Observations of the crack density effect and aspect ratio on anisotropic parameters at Serbal-1 within Pimienta Formation.

4.3.4.4 Comparison with other studies of shale reservoirs

Previous studies aimed at a rock physics characterization of anisotropic rocks in shale reservoirs are best exemplified by research that has been undertaken into the Lomgmaxi Shale, a case study using VTI (transverse isotropy with a vertical asymmetry axis) (Guo and Liu, 2018). Their aim was to better understand the relations between the mechanical and elastic parameters. They introduced the clay lamination index (CL) in the Backus average method and anisotropy enhanced by bed-parallel fractures described by the Chapman model (Chapman et al., 2002).

Figure 4.28 shows the comparison of results of Lomgmaxi Shale (Guo and Liu, 2018) and the results from this study of the Pimienta Formation. The main difference is that in this research thesis the modelling approach includes HTI-type anisotropy and not just VTI. In addition, the azimuthal response of the amplitudes and their reflectivity curves with angle incidence is also computed.

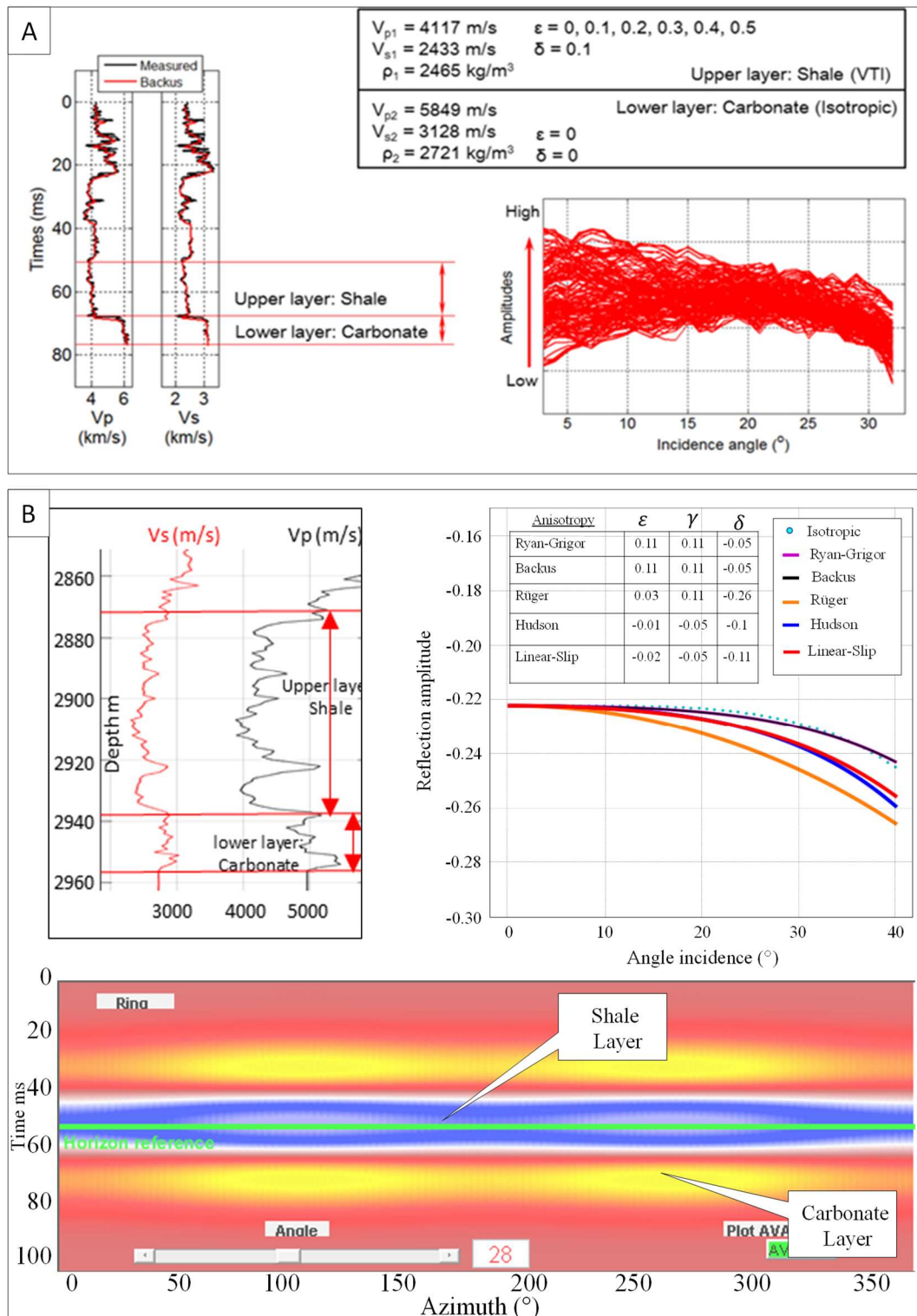


Figure 4.28 (A) Guo and Liu (2018), Seismic rock physics characterization of anisotropic shale a Longmaxi Shale case study. A model designed for seismic inversion for the Longmaxi Shale in VTI. The lower right panel illustrates AVO amplitudes picked from real data; (B) Anisotropic Shale characterization of the Pimienta Formation, with an azimuthal synthetic model through linear Slip modelling and AVA amplitude picked from the synthetic at 28° angle of incidence using different approaches of fracture models in effective medium for HTI at Serbal-1.

4.3.5 Links and comparisons between the various fracture models, interpretation of fracture compliances in the linear slip theory

This thesis project has documentation that demonstrates the validity of these models and the relationship between them. Hsu and Schoenberg (1993) made measurements in simulated fractured media to test the assumptions of the linear slip model. They found that the linear slip theory agreed well with laboratory measurements. In this chapter, I explore the main results of Hudson's (1981, 1997) laboratory measurements using theoretical predictions from his penny crack model. The objective is to analyze the validity of the relationship between the linear slip model and the penny-shaped crack model.

For this purpose, I will consider the experiment of Hsu and Schoenberg (1993) described here, in which they measured the velocity in a rough-surfaced plexiglas plate, pressed together with static normal stress, to simulate a fractured medium.

In the experiment, the third axis is orthogonal to the fracture surface, the effective average model is VTI (transverse isotropy, vertical axis of symmetry). Measurements perpendicular, parallel and oblique to the crack showed that, for wavelengths greater than the single thickness of the plate, the plexiglass plate can be modeled as a specific type of VTI media that depends on four parameters: normal fracture compliance and tangential and two an isotropic background module. This behavior of a VTI medium is identical to that of an embedded isotropic solid with a set of parallel linear slip interfaces.

Under this assumption, the elastic stiffness matrix of the effectively fractured medium can be derived based on only four measurements of the velocities of the P and S waves, polarized parallel and perpendicular to the fracture plane. However, for the linear slip assumption, an additional constraint must be satisfied (eq. 4.31).

$$C_{11}C_{33} - C_{13}^2 = 2C_{44}(C_{11} + C_{13}) \quad (4.31)$$

In their experiments, Hsu and Schoenberg fitted a TI model to five different measurements made under different pressure regimes to obtain five elements of the stiffness matrix.

$(C_{11}, C_{33}, C_{44}, C_{66}, C_{13})$.

Table 4.6 shows the five VTI moduli. Normalized by the density of the bulk lucite, determined from the five ultrasonic measurements of velocities. These velocities were performed at different stress states, from 6MPa to 24MPa.

To confirm the linear slip theory, they again predict the off-diagonal terms of the C'_{13} stiffness matrix using the equivalent equation 2.17 for a model with a vertical axis of symmetry, based only on measurements $(C_{11}, C_{33} \text{ and } C_{66})$ values of the C'_{13} , normalized by density are in column number 7 of Table 4.6.

Stress (Mpa)	C_{11}/ρ (Mpa m3/Kg)	C_{33}/ρ (Mpa m3/Kg)	C_{44}/ρ (Mpa m3/Kg)	C_{66}/ρ (Mpa m3/Kg)	C_{13}/ρ (Mpa m3/Kg)	C'_{13}/ρ (Mpa m3/Kg)
6	6.65	4.49	1.51	1.85	2.2	2.22
12	6.97	5.47	1.66	1.85	2.65	2.7
18	7.07	5.95	1.74	1.86	2.86	2.98
24	7.12	6.15	1.76	1.86	3.02	3.07

Table 4.6 Elastic stiffness coefficient in VTI mode from the experiment.

In the next step in the experiment, they derived the excess compliances (normal and tangential) caused by fractures (E_N and E_T). These compliances decrease with increasing stress which means that the asperities on either side of the plates are closer, implying that the contact area is increasing on the fracture surface.

The laboratory measurements and their fit are summarized to a linear-slip theory for all stress states previously mentioned as derived by Hsu and Schoenberg (Table 4.6). the velocities V_p and V_s are inverted for the unfractured Lucite block. The normal compliance E_N is estimated using the P-wave propagation perpendicular to the fractures and the S-wave velocity polarized parallel to the fractures (Table 4.7).

Stress (Mpa)	Vs(m/s)	E_T	Vp(m/s)	E_N	Vp'(m/s)	$E_{N'}$
6	1363	0.22	2703	0.62	2.71	0.63
12	1363	0.11	2686	0.31	2.73	0.36
18	1364	0.06	2679	0.2	2.73	0.25
24	1365	0.05	2707	0.19	2.73	0.21

Table 4.7. V_p' and $E_{N'}$ are estimated from P-wave velocities propagating orthogonal and parallel to the fractures and the wave parallel to the fractures regarded to lucite block.

I investigated the relationship between the Hudson model (1981) and linear-slip using this method and a volumetric distribution. Using data from rock mechanics within the Pimienta Formation from four samples taken at various depths and confining pressures (Table 4.8), I also model the variation of the relative area of cracking of the surface of the fractures with increasing stress. This is done using Hudson's model (1997) with a planar distributions of cracks.

Depth (m)	sample	Vp(m/s)	Vs(m/s)	confined pressure (psi)	density(gr/cc)	v	E(Gpa)
2104	1	4248	2456	0	2.38	0.25	26.84
2108	2	4369	2528	500	2.35	0.25	26.37
2114	3	4325	2441	1000	2.55	0.26	31.55
2121	4	4005	2337	1500	2.59	0.26	41.12

Table 4.8. Rock mechanics data within Pimienta Formation, static measurement of Young's Modulus and Poisson's ratio.

For the estimation of crack densities using Hudson's penny-shaped model using the samples information at different depths of the Pimienta Formation, I use Equation 4.32 and Equation 4.33 to explore the equivalence between the linear-slip and Hudson's model for dry cracks to obtain the relation between fracture weaknesses and crack density for dry cracks.

$$\Delta_N = \frac{4e}{3g(1-g)} \quad (4.32)$$

$$\Delta_T = \frac{16e}{3(3-2g)}$$

The Δ_N and Δ_T are not independent and Δ_N in terms of Δ_T are related in following form:

$$\Delta_N = \frac{3-2g}{4g(1-g)} \Delta_T = \frac{(2-\nu)(1-\nu)}{(1-2\nu)} \Delta_T \quad (4.33)$$

I obtain two different values for crack density using both weaknesses values which must satisfy the next conditions:

$$0 < \Delta_N < 1 \quad (4.34)$$

$$0 < \Delta_T < 1$$

$$\Delta = 0 \text{ for unfractured rock}$$

$$\Delta = 1 \text{ rock that lost coherence and fal apart}$$

Then (eq. 34) the crack density should validate these conditions

$$0 < e < \frac{3}{4}g(1 - g) \quad (4.35)$$

$$0 < e < \frac{3}{16}g(3 - 2g)$$

I compare the results of Hsu and Schoenberg with Hudson's (1997) model with a planar distribution of cracks.

As the confining stress is increased, the same procedure applied using four samples at different depth within Pimienta Formation with different confining pressure (Table 4.9).

Depth (m)	Confined pressure (psi)	g	Crack Porosity	Aspect Ratio	Crack density
2104	0	0.334	0.029	0.150	0.046
2108	500	0.335	0.028	0.160	0.042
2114	1000	0.319	0.022	0.150	0.035
2121	1500	0.340	0.013	0.150	0.021

Table 4.9. Summarizes the calculations for crack density from crack porosity and aspect ratio at different confining pressures within Pimienta Formation. All these values are smaller than 0.1, which is the theoretical limit of validity for Hudson's (1981) model with a volumetric distribution of cracks.

I derive the equivalent crack densities using Hudson's (1997) model with planar distributions of cracks. The aspect ratio of the cracks is 0.1 on average within the Pimienta Formation. One important observation is that all the estimated crack density values are smaller than 0.1, the limit of validity for Hudson's model (1981) The highest estimated crack density value is 0.046 at 2014m within the Pimienta formation.

The crack density decreases as we increase the normal stress with aspect ratio average of 0.1 and crack porosity of 0.02 (Table 4.9) as with the equivalent values calculated using Hudson's model (1981). Good agreement is observed between the laboratory measurements on the simulated fractured medium (Hsu and Schoenberg, 1993) and the theoretical predictions of the penny-shaped crack models of Hudson (1981, 1997) (Figure 4.29).

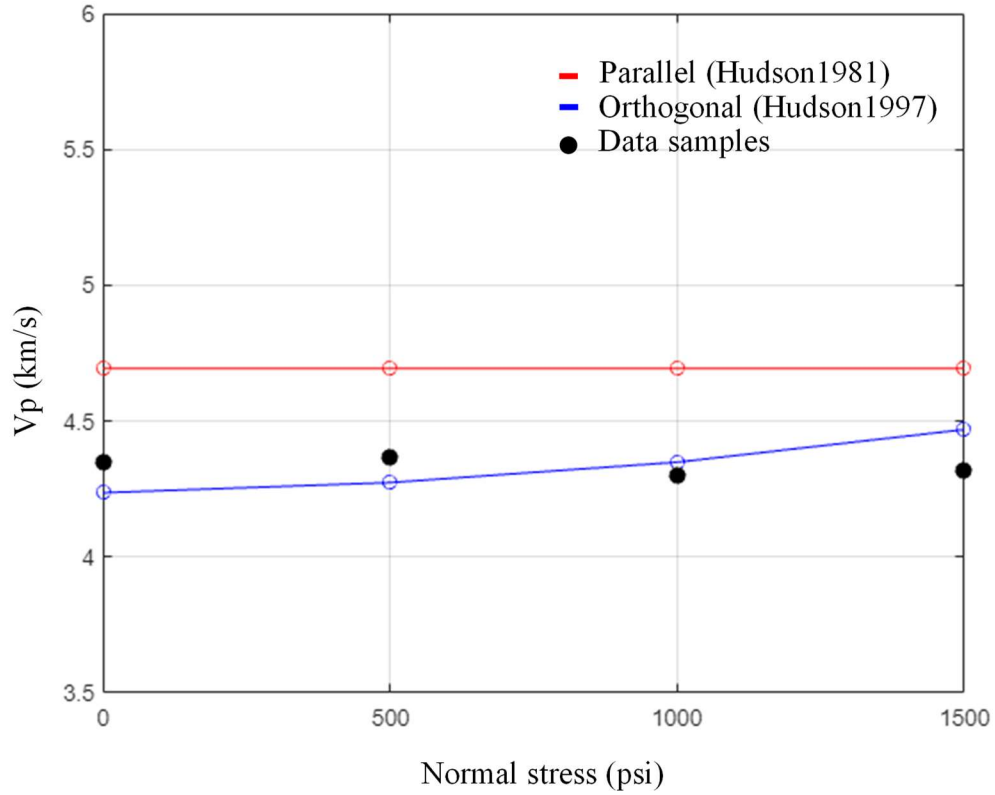


Figure 4.29. Comparison between ultrasonic velocity measurements at different depths within Pimienta Formation on simulated fractured medium (Hsu and Schoenberg, 1993) – red dots (Parallel), and blue dots (orthogonal) using the theoretical predictions of Hudson’s models for volumetric distribution of cracks (Hudson, 1981) and planar distribution of cracks (Hudson, 1997). Aspect ratio of the cracks is considered 0.1 according to table 4.9.

Another observation is the similarity of the results from Hudson’s (1981, 1997) two different models with volumetric and planar distributions of cracks. This demonstrates that to the first order, it does not matter whether the cracks are distributed volumetrically or confined in planar surfaces.

The first-order equivalence between Hudson’s model and the linear-slip model implies that for a certain crack density, the ratio between the normal and tangential weaknesses is fixed for dry cracks.

Furthermore, the weaknesses (Δ_N and Δ_T) are not independent.

Discussion

When the seismic wavelengths are much larger than the fracture size and spacing, it is convenient to use elastic compliance to formulate the equivalent anisotropic medium problem for seismic modeling of sets of aligned fractures embedded in host medium. The linear slip theory (Schoenberg and Sayers, 1995) provides a direct method to relate the seismic signatures to the properties of fracture systems. Normal (Δ_N) and tangential (Δ_T) weaknesses, introduced by Hsu and Schoenberg (1993), are two essential parameters of linear slip theory for rotationally invariant fractures. For penny-shaped cracks, by comparing Schoenberg's method and Hudson's method (1981), the normal and tangential weaknesses can be expressed in terms of the crack density and the ratio of P-wave and S-wave velocities of the host rock. A set of vertical, aligned, rotationally invariant fractures leads to a particular HTI medium called TI (LSD).

Only four independent parameters are required to specify a TI (LSD) medium. Rüger's anisotropic parameters for TI (LSD) media ($\delta^{(V)}$, $\varepsilon^{(V)}$, $\gamma^{(V)}$) can be expressed in an approximated linear form in terms of the normal and tangential weaknesses and the ratio of P-wave and S-wave velocities. If the cracks are dry, the $\gamma^{(V)}$ approximately equals density. Interactions between fractures and the shape of cracks do not affect the accuracy of Schoenberg's method, according to Grechka and Kachanov (2006).

The information that can be obtained from seismic data is only the fracture orientation and a rough estimate of crack density. The estimation of shape, size, and distribution of the fracture is beyond the capability of long wavelength seismic data.

The effective medium theory above is based on several assumptions. The theory assumes that the cracks in the host rock are isolated and penny-shaped. Real fractures, however, are not always isolated voids with low aspect ratio in the host rock. So, the validation of the effective medium theory to practical field data seems to be a critical issue for the use of this theory. It is very important to know if the results of this effective medium theory are accurate enough, in spite of the fact that some of the basic theoretical assumptions are violated.

For real field data, most aligned sets of fractures are connected, non-circular, microcorrugated, and have a considerable aspect ratio. If there is more than one fracture set in a host rock, intersecting fractures might occur. However, Grechka and Kachanov (2006) state that, “Micromechanics analysis identified several geometric features of cracks that are insignificant for the effective properties. These features are (1) Fracture intersections; (2) Microcorrugation of fracture faces; and (3) Random irregularities of fracture shapes, provided that the cracks are flat.” For a single set of fractures, I am mainly concerned with the effect caused by the interaction and the irregularities of fracture shapes which violate basic assumptions.

A model for interconnected cracks was proposed by Pointer et al. (2000) with equant porosity. An earlier model for aligned cracks was developed by Hudson et al. (1996). A theory for isolated cracks that are partially saturated with a single fluid was put forward by Hudson (1988). Model (a) was also studied by O’Connell & Budiansky (1977) and Mavko & Nur (1975). Partially saturated cracks have been investigated by Walsh (1965) and Mavko & Nur (1979). The results for cracks with equant porosity have also been given by Thomsen (1995) and Chapman (2003).

The occurrence of fluid flow either between cracks within cracks, or from cracks into a porous matrix lowers the mechanical strength of rocks, and has a marked effect on seismic properties, even though the volume occupied by the cracks and pores may be small. Seismic velocities exhibit behavior that is intermediate between that of empty cracks and that of isolated liquid-filled cracks over the range of frequencies in which fluid flow is significant. There is high attenuation and dispersion that becomes anisotropic if the cracks are aligned (Pointer et al. 2000; Chapman 2003).

Figure 4.30 (Grechka and Kachanov, 2006) shows how the interaction of fractures affect the anisotropic parameters with increasing crack density. When the crack density is lower than 0.05, the effects in Figure 4.30 (A) and Figure 4.30(B) for $\varepsilon^{(V)}$, and $\delta^{(V)}$ are tolerable. The effects decrease with decreasing crack density, and disappears when crack density becomes 0, which on the face of it seems reasonable. We are more concerned with the effect on $\gamma^{(V)}$ in figure 4.30(C) which is the direct estimation of crack density. Surprisingly, the interaction almost has no effect on $\gamma^{(V)}$ so that violating

the assumption of non-interaction is not going to reduce the accuracy of the result calculating by Schoenberg's theory.

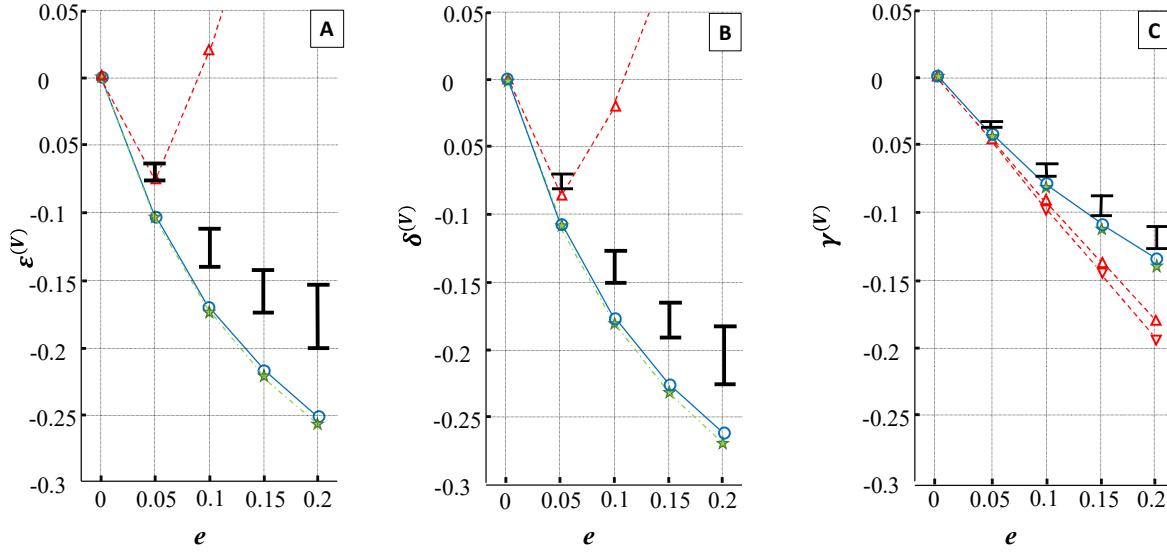


Figure 4.30. Anisotropic parameters (A) $\epsilon^{(V)}$, (B) $\delta^{(V)}$ and (C) $\gamma^{(V)}$ for a single set of vertical penny-shaped dry cracks (Grechka and Kachanov, 2006). Note: The background P-wave velocity is 3.0 km/s and S-wave velocity is 1.0 km/s; and density is 2.2g/cm³. Symbols indicate different theoretical predictions: red ∇ -the first-order Hudson's method, red Δ -the second-order Hudson's method, Schoenberg's method, and blue O -the non-interaction approximation (Grechka and Kachanov, 2006) that considers the crack aspect equals 0.05 for all fractures. Bars correspond to the 95% confidence intervals (the mean values of standard deviations) of the numerically computed anisotropic parameters obtained for 100 random realizations of the fracture locations.

Finally using the data from Table 4.9 using the crack density at Anhelido-1 and the values of anisotropy (within the Pimienta Formation) suggest a similar behavior to the model of Grechka and Kachanov (2006) where crack density increases with normal stress and the anisotropy becomes more negative using effective medium theory (Figure 4.31).

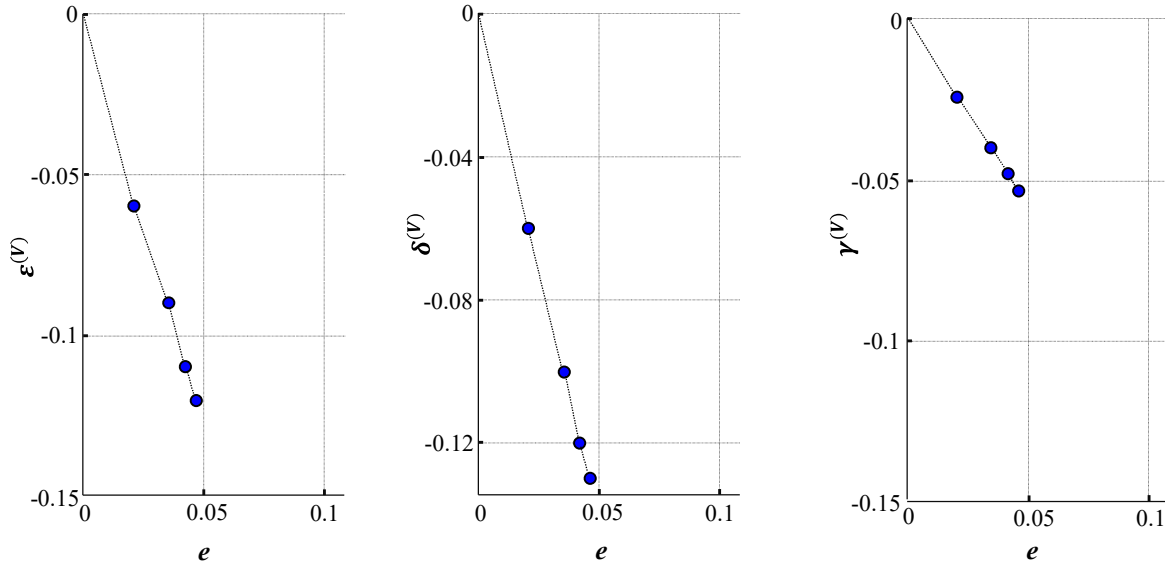


Figure 4.31. Anisotropic parameters (A) $\varepsilon^{(V)}$, (B) $\delta^{(V)}$ and (C) $\gamma^{(V)}$ from four samples at different confining pressures within Pimineta formation at Anehldo-1.

4.3.6 Discussion of the link between the B_{ani} parameter and non-fracture rock properties, as discussed in the literature

Fracture density is a term used in the field of geophysics to refer to the concentration of fractures in a rock formation. Fractures can affect the physical properties of rocks, such as their permeability and elasticity, and can be detected using geophysical techniques such as AVO (amplitude versus offset) analysis. In AVO azimuthal analysis, the orientation of the fractures is also considered, which can provide additional information about the fractures and the rock formation. This type of analysis can be used to identify the presence of fractures and to map their distribution in the subsurface, which can be useful for a variety of applications such as oil and gas exploration.

The visualization of the B_{ani} and ϕ attributes are combined tool (3D Viewer) for a display of fracture intensity and the primary direction of fracturing. I analysed the AVAz attributes analysis algorithms on the 3D azimuthal seismic data to estimate the anisotropy magnitude and the isotropy planes. The

AVAz anisotropy magnitude within a 3D volume shows areas where the amplitudes hold the greatest variability with azimuth, and the isotropy plane azimuth indicates the direction that the anisotropy is striking. The results give information not only on the relative degree of anisotropy in the Pimienta Formation but the directional variations of that anisotropy as well.

In this case study, Pre-Stack 3D seismic AVAz data is used to detect anisotropy due to the presence of fractures/or stress to directly identify fractured prone sweet spots for appraisal and field development plans. Properly conditioned input seismic and well data is used as input for AVAz modelling and attributes analysis at the well log and seismic scale this is performed as a basic practical requirement of the AVAz methodology to detect the intensity and direction of anisotropy. For AVAz modelling, Horizontal Transverse Isotropy (HTI) model and Linear Slip (LS) models are used for modelling the subsurface fractured media which helped to understand amplitude in azimuth response due to anisotropy caused by fractures or stress.

In a 3D prestack seismic survey the amplitudes are recorded at different azimuths and angles of incidence where AVAz is observed. The probable cause of the AVAz might be the result of an orientated anisotropic medium. In recent studies of HTI medium, it is possible to invert fracture density and orientation from AVAz information.

Approximation of reflection coefficients for HTI media, as presented in Equation 5.1 can permit a generalized linear inversion, like conventional AVO estimation when the incidence angles, azimuths and reflection coefficients are known (A , B_{iso} , B_{ani} and ϕ_{sym}). Hence, B_{ani} might remain the only anisotropic parameter to be inverted as crack density.

However, the B_{ani} inverted from real seismic data can never be said to be proportional to crack density due to the band-limited feature of seismic data and phase complexity. Scaling the inversion results to realistic crack density is thus being studied.

The AVAz modelling at the two existing wells provided a way to analyse the AVAz analysis result from B_{ani} . The AVAz attributes analysis helped to identify the anomaly of anisotropic gradient (B_{ani}) in order to identify fracture density or stress magnitude in target intervals caused by the

existence of intrinsic anisotropy, fine stratigraphic layering, fractures induced or stress- induced anisotropy.

Near offset Rüger equation results showed a promising indication of anisotropic gradient (*Bani*) and azimuth as the orientation of isotropy plane show that the high anisotropy in Serbal-1 and low anisotropy around Anhelido-1 in the vertical part. For example, in Figure 4.32 a forward model is shown of azimuthal synthetic ring gathers using the anisotropic parameters using approximation of Ryan-Grigor at different incidence angles.

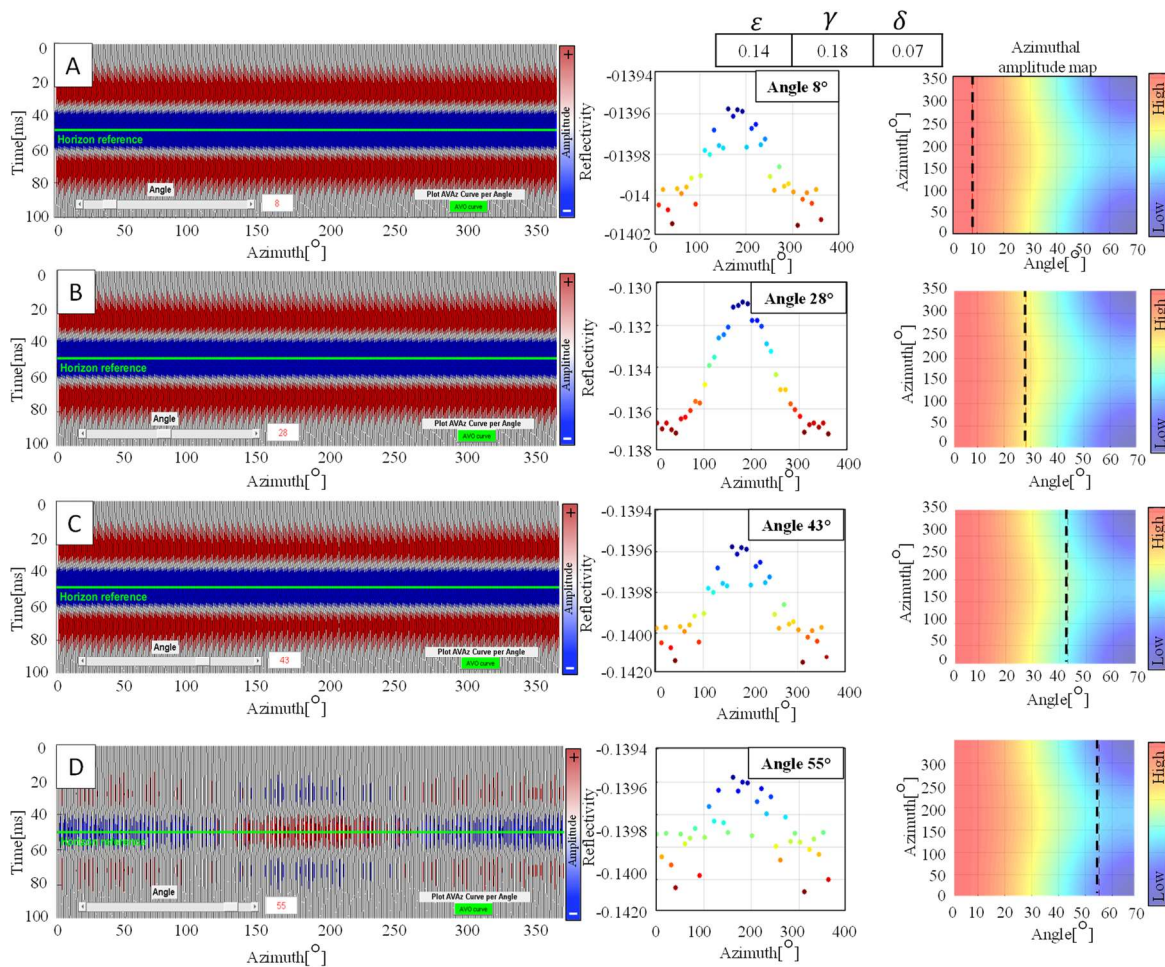


Figure 4.32 Azimuthal ring gather synthetic using Ryan-Grigor anisotropic parameters from well log data at Anhelido-1 within Pimienta Formation.

Finally, I evaluated AVAZ analysis based on Rüger equation using 3D Pre-Stack seismic data set from a shale reservoir within Pimienta Formation in Burgos Basin, onshore Mexico. To confirm the maximum horizontal stress, I used the stress map (Figure 4.22). The existence of anisotropy suggests the presence of intrinsic anisotropy, fine stratigraphic layering, or highly possible due to the presence of fractures or localized stress-induced anisotropy but this is qualitative due to a sonic scanner log should be tested to confirm this assumption. This would help to predict the presence of fracture-prone zones and hence achieve optimum hydrocarbon recovery.

The AVAZ technique is sensitive to the contrast in two Thomsen parameters $\gamma(v)$ and $\delta(v)$ (these describe layer-localized shear wave splitting and layer-localized P wave NMO velocity differences parallel and perpendicular to fractures, respectively) across an interface. The AVAZ inversion is based on that class of anisotropy known as horizontal transverse isotropy (HTI). The HTI model assumes the existence of locally mono-oriented sets of vertical fractures. Unfortunately fracture sets in the real world do not always conform to this simple configuration:

The inherent errors are so large and variable that the fracture intensity attributes from AVAZ inversion are not suitable for use as direct quantitative interpretation of fracture intensity. However, the relative differences of fracture intensity attributes from AVAZ inversion qualitatively agree with the actual intensity differences and may be exploited as a qualitative measure of fracture intensity variation applied to a very limited range of incident angles. For noisy data, it is difficult to characterize fracture azimuth, not only by a single inversion but also by a statistical mean of multiple inversion results and an effective de-noising processing strategy is a critical step for fracture azimuth inversion.

For fracture research, using borehole logs or cores are the direct and intuitive methods to study the subsurface fractures. However, there are some limitations and problems from the method itself and the sampling problem is the most important one. For example, commonly mode 1 fractures in the subsurface are nearly vertical, and since most boreholes are vertical the wellbore trajectory commonly runs parallel to the fractures. If the wellbores do not intersect the fracture sets, the information

recovered from the logs might be of limited value. Because of this limitation, a more challenging method, based on seismic exploration, is required and it leads to a valuable and reliable tool for fracture characterization. The orientation and density of fracture sets from the effective medium theory above is based on several assumptions. The theory assumes that the cracks in the host rock are isolated and penny-shaped. Real fractures, however, are not always isolated voids with low aspect ratio in the host rock. So, the validation of the effective medium theory to practical field data seems to be a critical issue for the use of this theory. It is very important to know if the results of this effective medium theory are accurate enough, although some of the basic theoretical assumptions are violated. For real field data, most aligned sets of fractures are connected, and have a considerable aspect ratio. If there is more than one fracture set in a host rock, intersecting fractures might occur. However, Grechka and Kachanov (2006) state that, “Micromechanics analysis identified several geometric features of cracks that are insignificant for the effective properties.

4.4 Discussion

The results on fractured models are discussed below along with the implications of the anisotropy observations that allow the estimation of an azimuthal seismic model and its differences as a function of the effective medium employed. The key observation is summarized as follows:

The use of Backus averaging for elastic properties within the Pimienta Formation case study using well log data allows the estimation of the Thomsen’s parameters. The elastic properties of P-Sonic and S-sonic logs were upscaled as an average of a stack of thin layers at a longer wavelength of the seismic data, so possibly the anisotropy obtained with Backus is not significant due to the seismic scale compared to (e.g., Hudson, Linear-slip) where cracks are considered.

For each effective medium model (e.g., Hudson, Linear-slip), it was found that the values of anisotropy change depending on which effective medium model is applied (penny-shaped cracks or vertical fractures). The azimuthal seismic image model for each effective medium fracture model

shows slight amplitude distortions associated with the differences in the values of Thomsen's parameters.

The effect of amplitude vs azimuth (AVAz) begins to reveal azimuthal amplitude distortion at 28° of angle of incidence (see section 4.3.3.2). The distortions in amplitude are related to the type of effective medium models (cracks-fractures) and are visible only at far incidence angles. For that reason the full suite of fracture models were restricted to this threshold incidence angle.

The estimation of the elastic stiffness constants allows the anisotropic values to be computed for each model. These values are presented in Table 4.10 corresponding to Anhelido-1 at depth 2113m and in Table 4.11 for the well Serbal-1 at depth.

Elastic Constants (GPa) VTI	Anisotropic parameters VTI	Elastic Constants (GPa) HTI	Anisotropic parameters HTI	Rüger Thomsen	Hudson model	Linear-slip model	Ryan-Grigor
$C_{11} = 83.82$	$\varepsilon^{(V)} = 0.14$	$C_{11} = 65.33$	$\varepsilon^{(V)} = 0.11$	$\varepsilon^{(V)} = 0.14$	$\varepsilon^{(V)} = -0.08$	$\varepsilon^{(V)} = -0.01$	$\varepsilon^{(V)} = 0.14$
$C_{13} = 33.12$	$\gamma^{(V)} = 0.16$	$C_{13} = 25.99$	$\gamma^{(V)} = 0.12$	$\gamma^{(V)} = 0.16$	$\gamma^{(V)} = -0.04$	$\gamma^{(V)} = -0.04$	$\gamma^{(V)} = 0.18$
$C_{33} = 65.33$	$\delta^{(V)} = -0.32$	$C_{33} = 83.82$	$\delta^{(V)} = -0.17$	$\delta^{(V)} = -0.17$	$\delta^{(V)} = -0.07$	$\delta^{(V)} = -0.13$	$\delta^{(V)} = 0.07$
$C_{44} = 19.66$		$C_{44} = 26.26$					
$C_{66} = 26.26$		$C_{66} = 19.66$					

Table 4.10 Effective elastic constants stiffness based on different approximations for Anhelido-1 at depth 2113m.

Elastic Constants (GPa) VTI	Anisotropic parameters VTI	Elastic Constants (GPa) HTI	Anisotropic parameters HTI	Rüger Thomsen	Hudson model	Linear-slip model	Ryan-Grigor
$C_{11} = 41.42$	$\varepsilon^{(V)} = 0.03$	$C_{11} = 38.62$	$\varepsilon^{(V)} = -0.03$	$\varepsilon^{(V)} = 0.03$	$\varepsilon^{(V)} = -0.01$	$\varepsilon^{(V)} = -0.02$	$\varepsilon^{(V)} = 0.11$
$C_{13} = 7.98$	$\gamma^{(V)} = 0.11$	$C_{13} = 11.50$	$\gamma^{(V)} = -0.09$	$\gamma^{(V)} = 0.11$	$\gamma^{(V)} = -0.05$	$\gamma^{(V)} = -0.05$	$\gamma^{(V)} = 0.11$
$C_{33} = 38.62$	$\delta^{(V)} = -0.30$	$C_{33} = 41.22$	$\delta^{(V)} = -0.33$	$\delta^{(V)} = -0.26$	$\delta^{(V)} = -0.10$	$\delta^{(V)} = -0.11$	$\delta^{(V)} = -0.05$
$C_{44} = 13.55$		$C_{44} = 16.62$					
$C_{66} = 16.62$		$C_{66} = 13.55$					

Table 4.11 Effective elastic constants stiffness based on different approximations for Serbal-1 at depth 2908m.

The complete modelling of the “ring” synthetic azimuthal gather were separated in four main rings sorted in incidence angle (e.g., 8° , 28° , 43° and 55°) and azimuth (e.g., 0° - 360°) in Serbal-1 (depth: 2908m) within Pimienta Formation using the Thomsen’s Parameters of the Linear-slip model ($\varepsilon = -0.02$, $\gamma = -0.05$, and $\delta = -0.11$) to see the amplitude changes as a function of angle incidence and full azimuth range (Figure 4.16).

The amplitude changes seen in the “ring” synthetic azimuthal gather implies that as the incidence angle is moving from near angle to far angle is might potential be associated with the anisotropy, the distortion in the amplitudes is more evident for far angles of incidence than in those found at near incidence angles.

In this modelling chapter, I calculated the Hudson, Linear-slip, and Ruger-Thomsen models as an azimuthal seismic image display, and the difference between them is minimum according to the reflectivity curves in AVO plots.

From the results is clear that the observations in the amplitude distortions in the azimuthal synthetic gather for the two fracture models are slightly higher in Serbal-1. The result now provides evidence of induced anisotropy within the Pimienta Formation. These basic findings are consistent with research showing that the intrinsic anisotropy in a shale rock type (Thomsen, 1986) is also evident in the Pimienta Formation.

Finally, evidence is shown of VTI anisotropy ($\varepsilon=0.14$, $\gamma=0.18$) in Anhelido-1 at a depth of 2113 m and ($\varepsilon=0.11$, $\gamma=0.11$) and Serbal-1 at depth of 2908 m based on approximation of Thomsen’s parameters from Ryan-Grigor estimation (1998) which is based on data set of 71 shales that establish empirical relationships relating Thomsen’s parameters to V_p/V_s ratio for shales rocks.

The degree of anisotropy from well log is dependent on diagenesis, TOC content, and stratigraphy of the Pimienta Formation

The existence of anisotropy suggests the presence of intrinsic anisotropy, fine stratigraphic layering, or highly possible due to the presence of fractures or localized stress-induced anisotropy but this is qualitative

One limitation of fracture density in AVO azimuthal analysis is that it is based on the assumption that the fractures are oriented in a certain way, and that their orientation is known. If this assumption is not valid, then the results of the analysis may not be accurate. Additionally, AVO azimuthal analysis can be sensitive to the presence of other factors that can affect the physical properties of the rocks, such as the presence of fluids or changes in temperature. These factors can also affect the accuracy of the analysis and the interpretation of the results. Finally, AVO azimuthal analysis is a geophysical technique that can only provide indirect information about the fractures and the rock formation. It may be necessary to use other techniques, such as drilling or core samples, to confirm the presence of fractures and to obtain more detailed information about their characteristics.

Non-fractured rocks do not have any fractures or other types of discontinuities. These rocks are characterized by their homogeneity and uniformity, and their physical properties, such as their permeability and elasticity, are relatively constant throughout the rock. In contrast, fractured rocks are rocks that have fractures or other discontinuities, which can affect their physical properties and make them more heterogeneous and variable.

4.4.1 Fractured model limitations

The use of the Hudson Model should not be made without taking into consideration that there is a limitation in this model because it treats fractures as idealized, penny-shaped cracks. Furthermore, it assumes that crack spacing/distance is much smaller than the wavelength (Mavko,2009). The formal limit for the crack density in this model is 0.1.

The Linear-Slip Model works better in carbonate lithofacies instead of clay-rich shale rocks even though it was applied in this research fracture modelling to better understand the anisotropy in Pimienta Formation.

Finally, we note that all two models were used only for the dry case, not assuming fluid-filled for this Chapter. I will tackle the influence of fluid substitution in anisotropic rocks in Chapter 6.

4.5 Conclusions

Fracture models were analysed on effective media (e.g., Hudson and Linear-slip) intending to study the potential anisotropy within the Pimienta Formation. The analysis has shown that the models exhibit different values of anisotropy depending on the choice of effective medium. I compared these effective medium models with a real response to seismic data where I determined that in the vertical well Serbal-1, there is a slightly higher degree of anisotropy based on the B_{ani} model or fracture density compared to Anhelido-1, where it seems to have less degree of anisotropy in its vertical part within the Pimienta Formation.

Because fractures or cracks are sometimes below the seismic resolution, it is essential to apply this type of analysis to constrain the degree of rock anisotropy using Backus averaging.

The B_{ani} results suggest that in Serbal-1, there is greater anisotropy compared to Anhelido-1 within the Pimienta formation, according to the observations with different crack densities and aspect ratio (Figure 4.20).

With Increases in the value of crack density and aspect ratio, the anisotropy is higher in both wells (Table-4.4 and Table 4.5). The crack density value for Anhelido-1 is 0.03 at a depth of 2113m whereas for Serbal-1 it's 0.04 at 2908m, so it can be concluded in some way that crack density is slightly higher in this well which may induce anisotropy in this formation.

The linear-slip model is not a universal fracture model for natural fractured media. It works better in exceptional cases under certain conditions, for example when $\Delta_N = 0$ for fluid-saturated cracks (e.g., Bakulin et al., 2000) or $\Delta_N = \Delta_T$ may be related to unsaturated (dry) rocks.

The present findings in this chapter based on the fracture models in effective medium confirm the anisotropy within Pimienta Formation. Importantly the results in this chapter provide evidence that fractures and cracks have a strong influence on the anisotropic Thomsen's parameters.

5. Fracture detection using azimuthal AVO and rock physics

5.1. Introduction

Open fractures change the response of the rock in the subsurface as a function of the azimuth for the passage of the seismic wave between source and receiver. These effects are seen as changes in azimuthal velocity (or velocity of NMO interval) and amplitude (azimuthal AVO). Depending on the architecture of the reservoir and the acquisition geometry, both the orientation of fractures and intensity can be analysed by seismic attributes that must first have taken into account the anisotropic effect caused by fracturing system (Bratton et.al., 2006).

The quantitative calibration of seismic anisotropy from other sources of information such as cores and logs or microseismic data, reduces the degree of uncertainty in an adjustment process similar to that made with seismic and recorded well log velocities (Pistre, 2005, Patterson and Tang, 2007).

The Amplitude vs. azimuth (AVAz) method has been widely used to identify fractures using wide-azimuth seismic data (Hall et al., 2003; Gray et al., 2002). Fractures typically have apertures of a few millimetres or less so that they are much smaller than the typical seismic wavelength (10s of metres) at target depths for unconventional resources. An important limitation of AVAz is that this method can only detect swarms of fractures that are aligned close to the vertical.

It is also clear that fractures can strongly affect the reservoir and attenuate the seismic image and this effect on the wavefront can be seen from seismic modelling. If it is determined that a specific target stratigraphic interval has a family of horizontal or vertical fractures with potential to affect economic interest, we can represent this phenomenon through the anisotropy parameters and in the case of vertical fracturing, the horizontal transverse isotropy (HTI) (Ruger, 1997).

As we will see in the development of this work, to find the orientations and magnitudes of fractures present in the target interval, modelling focuses on fracture models and the anisotropy in effective media

Fractures can result in azimuthal anisotropy of both seismic shear waves (S-waves) and compressional waves (P-Waves). Crampin et al. (1980) first reported the observation of shear wave splitting caused by aligned fractures from an analysis of earthquake seismogram data. Alford (1986), and Lynn and Thomsen (1990) analyzed shear wave reflection data for shear wave splitting from multicomponent seismic surveys. They estimated the shear wave anisotropy from the time delays of the slow shear wave and the fracture orientation from the direction of the fast shear wave.

Azimuthal amplitude versus offset (AVO) is an analysis of azimuthal amplitude variations as a function of varying incidence angle of reflection coefficients (Figure 1.5). It is a measure of the change in elastic properties at an interface. It is used because it yields better vertical resolution than propagation methods for characterization of natural fractures or differential stress in a reservoir (Sayers et al., 2003).

The variation of reflection amplitude with angle of incidence and increasing offset is measured using AVO analysis procedures first instituted by Castagna (1993). The equations for the reflection coefficient have been presented in the literature (Knott, 1899; Zoeppritz, 1919; Aki and Richards, 1980; Waters, 1981). When fully derived, these equations are very complex.

P-wave anisotropic inversion is an extension of AVO (amplitude versus offset) by the incorporation of the Rüger anisotropic reformulation of Aki and Richard linearized equation for P-Wave reflectivity with incidence angle (Aki and Richards, 1980). It is based on an HTI model of vertically aligned fractures (Figure 5.1) (Ruger, 1997).

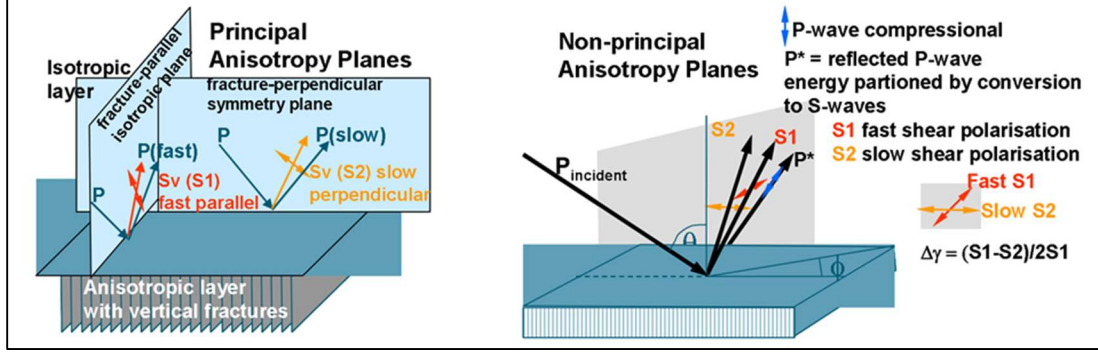


Figure 5.1 HTI model used in Ruger formulation (1997) P-wave reflection equation showing anisotropic conversion to shear-waves for principal and non-principal planes of symmetry.

The HTI model is identical to VTI (vertical transverse isotropy) for horizontal layers, e.g., shales. However, for HTI, ε and δ (VTI case) undergo a transformation to $\varepsilon^{(v)}$ and $\delta^{(v)}$: the vertical axis refers to the 90° symmetry axis rotation from the VTI model. HTI $\varepsilon^{(v)}$ and $\delta^{(v)}$ along with VTI γ appear in Ruger formulation for HTI AVAz reflection for azimuth angles ϕ between the principal symmetry axis plane and isotropic plane as shown in eq. (5.1).

$$R_p(\theta, \phi) = A + (B_{iso} + B_{aniso})\sin^2\theta + (C_{iso} + C_{aniso})\tan^2\theta\sin^2\theta \quad (5.1)$$

$$A = \frac{1}{2}\left(\frac{\Delta V_p}{V_p}\right) + \frac{1}{2}\left(\frac{\Delta\rho}{\rho}\right) = R_p(0) \quad (5.2a)$$

$$B_{iso} = \frac{1}{2}\left[\left(\frac{\Delta V_p}{V_p}\right) - \left(\frac{2V_s}{V_p}\right)^2 \frac{\Delta\mu}{\mu}\right] \quad (5.2b)$$

$$B_{aniso} = \frac{1}{2}\left[\Delta\delta^{(v)} + 2\left(\frac{2V_s}{V_p}\right)^2 \Delta\gamma\right]\cos^2\phi \quad (5.2c)$$

$$C_{iso} = \frac{1}{2}\left(\frac{\Delta V_p}{V_p}\right) \quad (5.2d)$$

$$C_{aniso} = \frac{1}{2}\left[(\Delta\delta^{(v)}\sin^2\phi\cos^2\phi) + (\Delta\varepsilon^{(v)}\cos^4\phi)\right] \quad (5.2e)$$

Where

A – is the intercept

θ – Incidence angle

B_{iso} is the isotropic gradient

V_p, V_s – P and S average velocities
across reflection interface

B_{aniso} is the anisotropic gradient

$\Delta\gamma, \Delta\epsilon^{(v)} \& \Delta\delta^{(v)}$ are the Thomsen's parameters
in HTI media

C_{iso} is the isotropic curvature

ϕ is the azimuth angle with respect
to symmetry axis plane $\phi = 0$

C_{aniso} is the anisotropic curvature

The aim of this chapter is to estimate the fracture density by applying the azimuthal AVO methodology to the seismic data set from the study area in the Burgos Basin, Northeast Mexico (Figure 5.4). More specifically, the intention is an estimation of the fast velocity orientation.

The effects of the fractures are apparent when seismic waves propagate through them by VTI medium and HTI medium when penny-shaped cracks and fractures are embedded in an isotropic horizontal background, (e.g., Thomsen, 1986; Tsvankin, 2001). Gradient changes as a function of azimuth: if there is no anisotropy the gradient does not change as a function of azimuth (e.g., circle with radius B_{iso}). In the isotropy plane the AVO has a gradient of B_{iso} and the symmetry plane the AVO has a gradient of $B_{iso} + B_{ani}$ also considering a sign ambiguity, implicit in the Rüger method.

In the case of fracture orientation ambiguity, the least-squares solution solves for the magnitude of B_{ani} . Because we do not know the sign of B_{ani} , there exist two equally valid solutions.

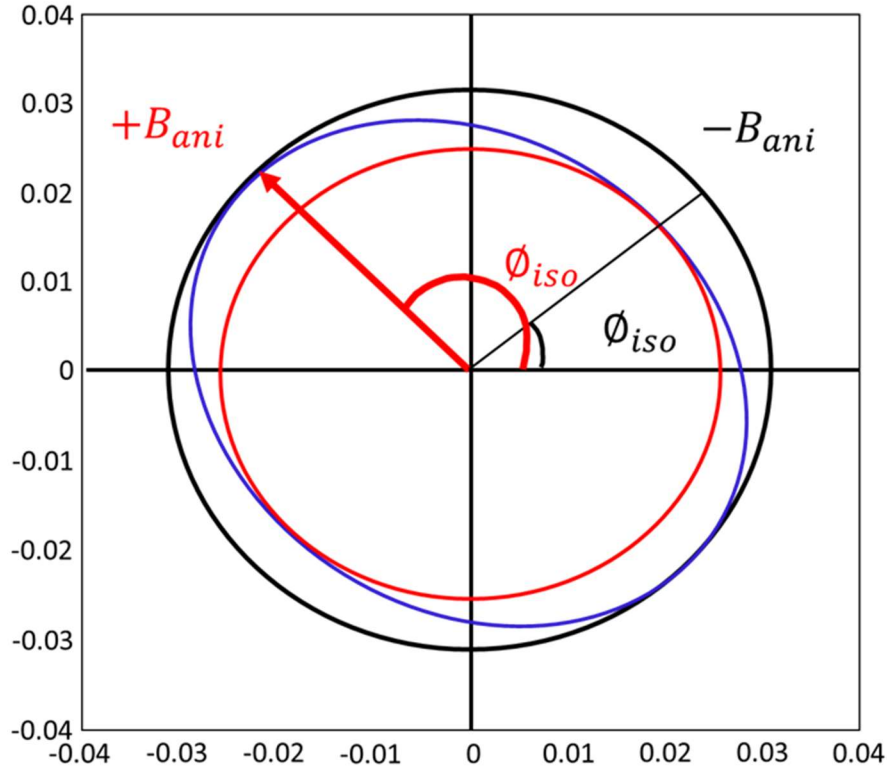


Figure 5.2. Azimuthal reflectivity for a constant angle of incidence

Both solutions in (Figure 5.2) represent the original background isotropic solution, which is perturbed by the anisotropic gradient. The positive B_{ani} disturbs the red background isotropic reflectivity to the blue ellipse. In this case, the isotropy azimuth plane is defined by a red line segment; the negative perturbs the black background isotropic reflectivity to the blue ellipse. In this case, the isotropy azimuth plane is characterized by a black line segment, note there is a 90° ambiguity between the two isotropy plane orientations, both potentially valid.

A fundamental step before conducting the Azimuthal AVO analysis is the conditioning of the seismic data. This can be done by starting from the angle if the velocity field is known or the offset seismic gathers are available. In these cases, the super gathering of azimuthal data can be done in two ways:

- (1) Common offset or common angle gathers with variable azimuth within each sector. This shows the amplitude fixed offset-angle within varying azimuth and is useful for determining the travel time variation due to anisotropy.

- (2) Common azimuth gathers with variable offset-angle within each sector: this allows the identification of azimuthally varying AVO amplitudes anomalies.

The azimuthal seismic data were sorted in common offset and common azimuth (COCA) introduced in the Hampson and Russell package. This preceded the velocity analysis versus azimuth (V_{vaz}) and the analysis of amplitude versus azimuth (AVAz) (Perz et.al., 2013; Cho et.al., 2015). Azimuthal effects in seismic gathers can be quite significant as presented in Section 3.2.1. Figure 3.5 shows an example of data from the study area portraying the velocity variation with azimuth.

If fractures are oriented in perpendicular directions, the medium will be the same in all directions and there will be no variation in the S waves and therefore an anomaly will not be generated. The method further assumes that the fractures are almost vertical and are filled with fluid. If the fractures are closed, there is no change in the medium and therefore the S waves are not will be affected. This leads to another important point. The azimuthal AVO methodology detects vertical fractures, open with a preferential orientation, regardless of type of fluid contained in the fractures. Consequently, this does not necessarily imply that the reservoir fractures are saturated with hydrocarbons.

HTI anomalies of velocity is the main goal of the azimuthal velocity analysis. Fractures can produce changes in the velocity field varying with the azimuth (Treadgold et.al., 2008). The effect is not perceptible in normal incidence but at higher incident angles the compressional wave can be delayed when it passes all the way orthogonally across a set of vertical fractures. In contrast, when it passes parallel to a vertical fracture set, a delay is not exhibited, and the compressional wave become fast (Figure 5.3).

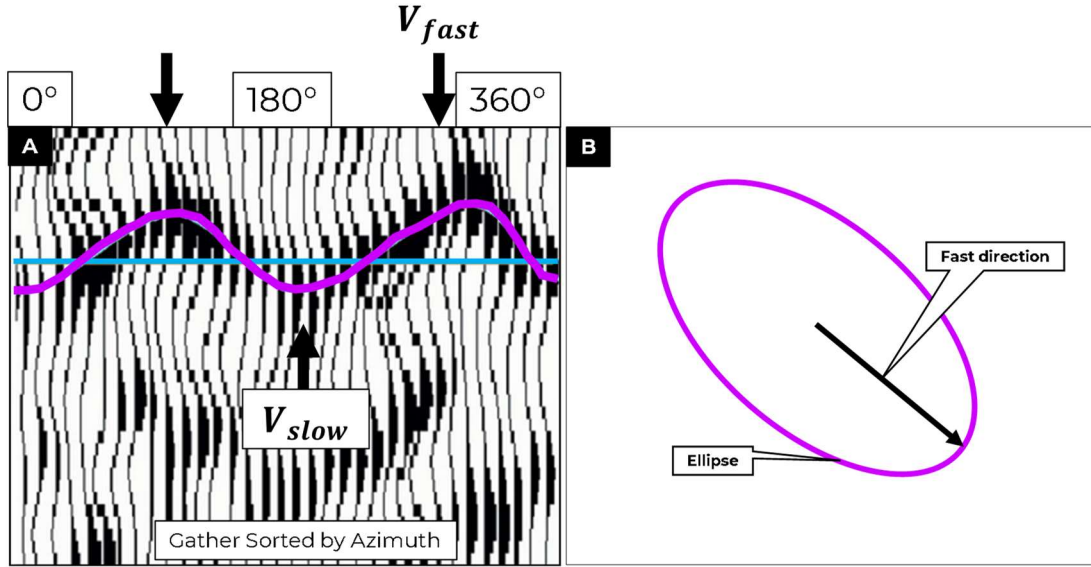


Figure 5.3 (A) Seismic gather sorted by angles and azimuths it shows apparent fast (V_{fast}) and slow (V_{slow}) azimuth;(B) The sinusoid (wobbling effect) describes a representative ellipse with the fast direction represented by long axis (modified from Treadgold et al., 2008).

5.2. Data and methods

The dataset used in this chapter include a 3D azimuthal seismic gather (1900 Km²) and well log data from two key wells (Ahelido-1 and Serbal-1). The number of traces in the azimuthal 3D seismic data is considerable in the study area. For that reason, two areas were selected to apply and perform the AVAz attributes (e.g., anisotropic gradient and azimuth) as a subset from the entire 3D azimuthal seismic survey specifically covering the area around Anhelido-1 and Serbal-1 (Figure 5.4).

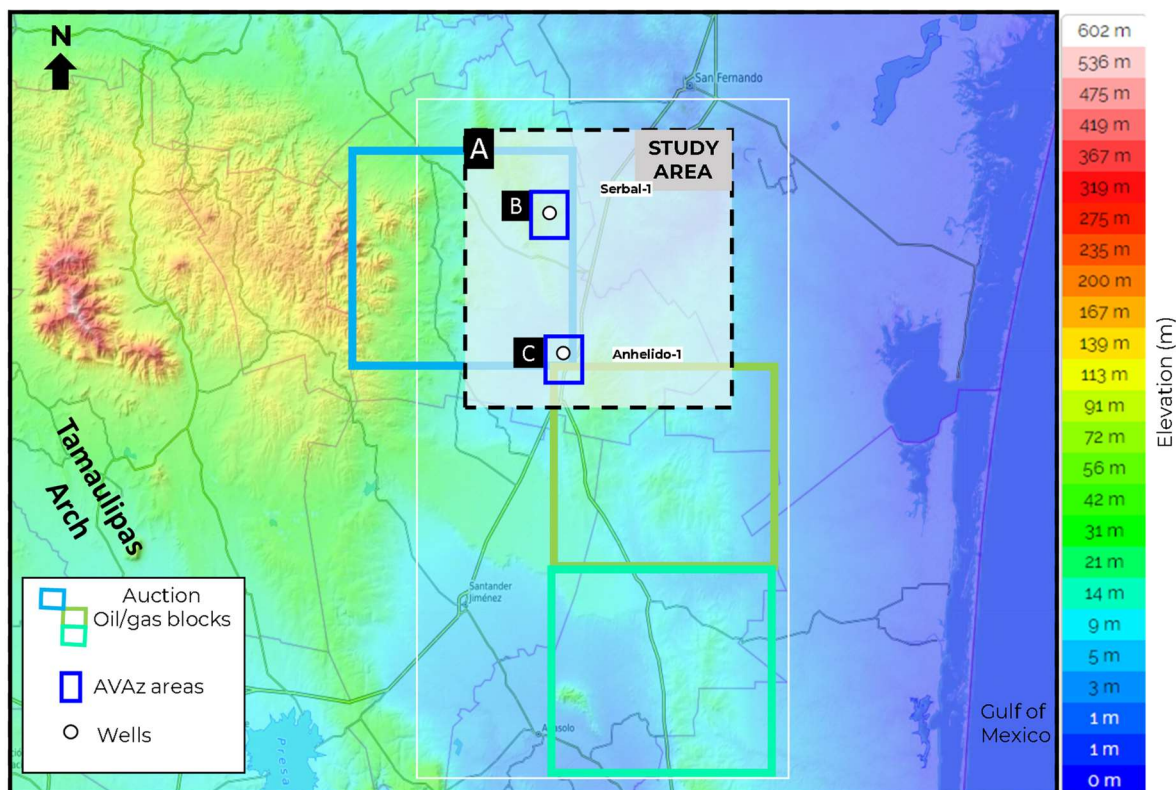


Figure 5.4 Map indicating the different areas where AVAz attributes were calculated within the study area and Pimienta formation; (A) Entire 3D seismic survey of study area; (B) Selected area around Serbal-1 for AVAz calculation; (C) Selected area around Anhelido-1 for AVAz calculation.

5.2.1 AVAz application within Pimienta Formation

To detect fractures in the study area, Azimuthal AVO (AVAz) analyses were applied over the entire area (Figure 5.5) in five wells (e.g., Mirasol-1, Espectro-1, Serbal-1, Anhelido-1, and Tres Palos-1). Cruillas-1 was not selected due to the fact that the seismic quality was not sufficiently accurate to apply the AVAz analysis as it is located on the edge of the 3D seismic survey with concomitantly reduced coverage. The analysis was applied using ProAz module of Hampson and Russell package which can handle azimuthal AVO.

The analysis might be possible to predict fracture maps and stress by observing azimuthal variations in the P-wave seismic data. As a first step, it is important to determine the range of incidence angles in the seismic gathers to perform the AVAz analysis. Medium-to-far angles generally exhibit greater

anisotropy as shown in Chapter 3.2.1 (Figure 3.5). In this project, multiple iterations were carried out to obtain an AVAz model that shows the areas with the highest percentage of anisotropy.

The azimuth gathers were sorted in a snail shape known as snail gather or (COCA) gather, that is, sorted increasing angle and increasing azimuth. Prior to this step, data conditioning is very important to improve the signal / noise ratio, although this does not significantly affect the response of the AVAz.

For each well within Pimienta Formation, the anisotropic gradient and azimuth was displayed in a single CDP in the well location (e.g., yellow square Figure 5.5). Mirasol-1 is found at trace 11503, and 2100ms TWT (Figure 5.6), Espectro-1 at trace 11269, and 1780ms TWT (Figure 5.7), Serbal-1 at trace 11355, and 1780ms TWT (Figure 5.8), Anhelido-1 at trace 11451, and 1300ms TWT (Figure 5.9), and finally Tres palos-1 at trace 12101, and 1880ms TWT (Figure 5.10).

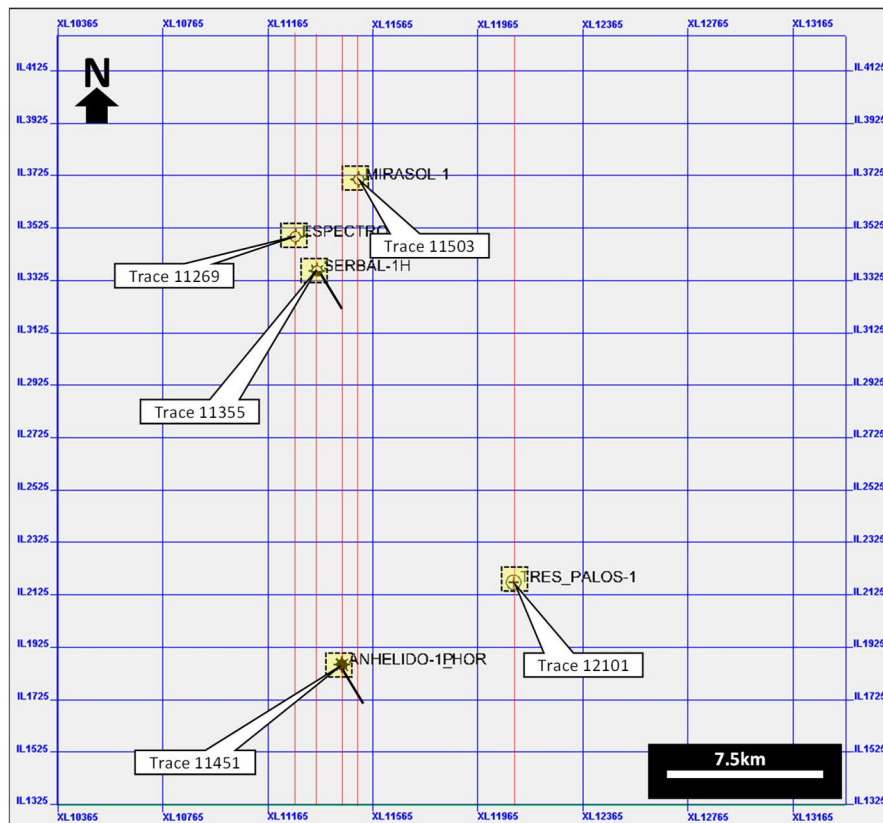


Figure 5.5 3D survey in the study area yellow square represent the points where the azimuthal gather was displayed in each well (red lines represent the number of traces selected).

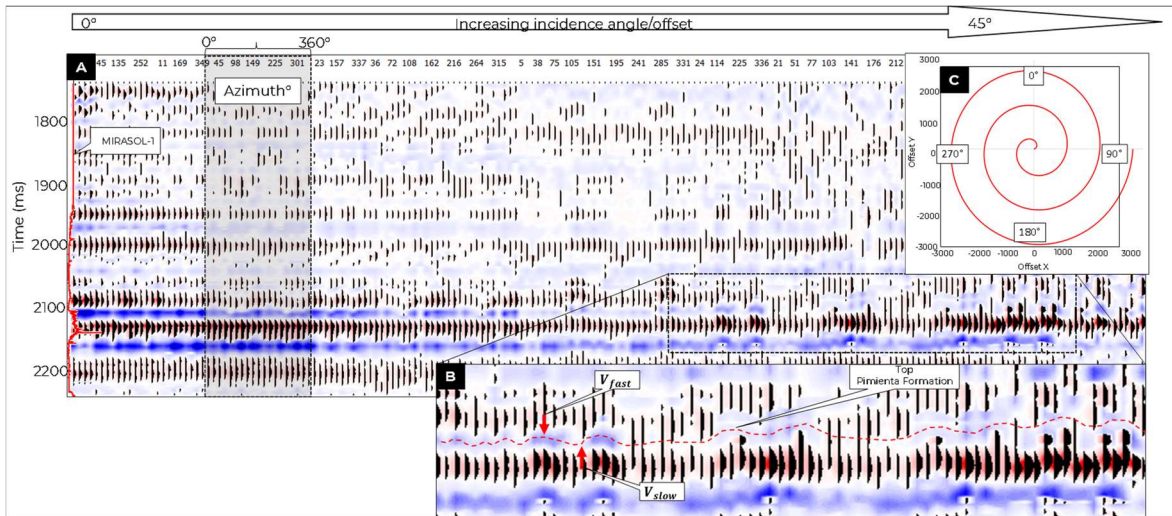


Figure 5.6 (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Mirasol-1 (trace 11503); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within Pimienta Formation; (C) Snail gather representation (Source: CGG University training material).

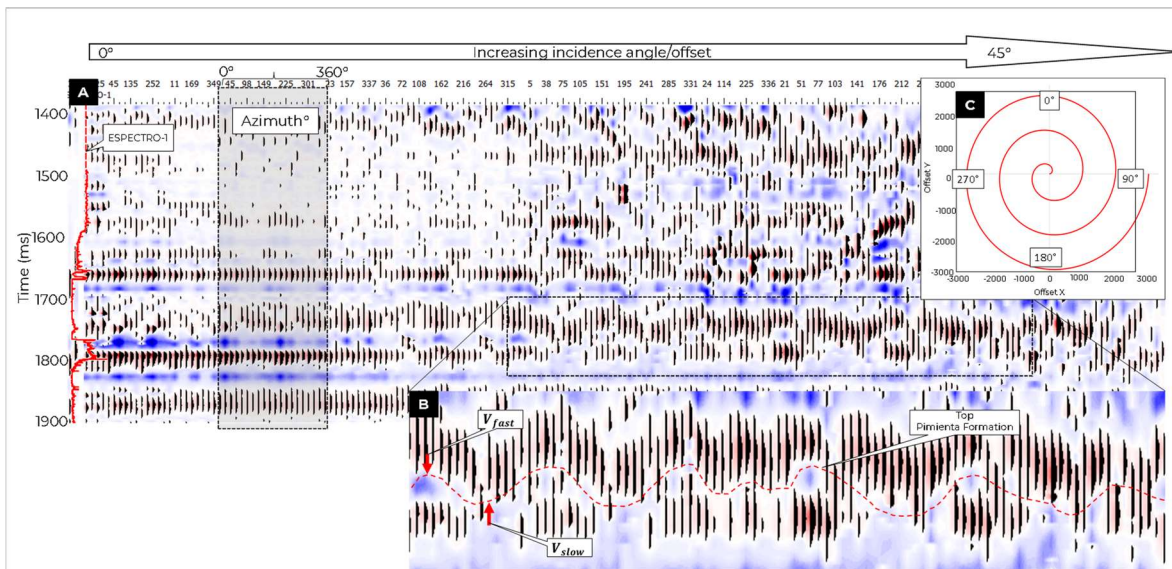


Figure 5.7 (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Espectro-1 (trace 11269); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within the Pimienta Formation; (C) Snail gather representation (Source: CGG University training material).

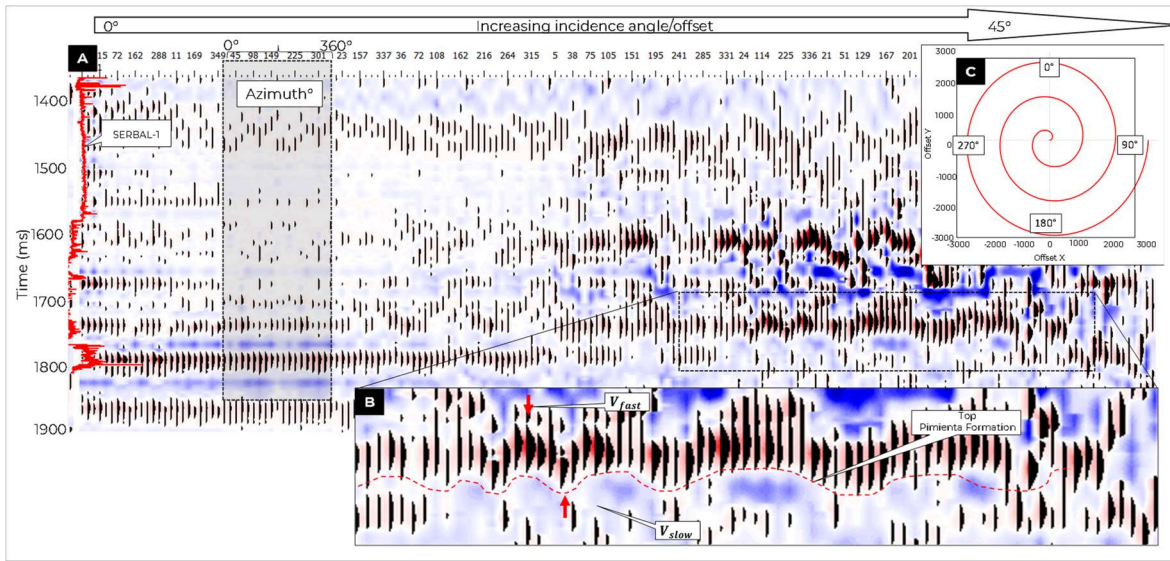


Figure 5.8 (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Serbal-1 (trace 11355); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within the Pimienta Formation; (C) Snail gather representation (modified from CGG University training material).

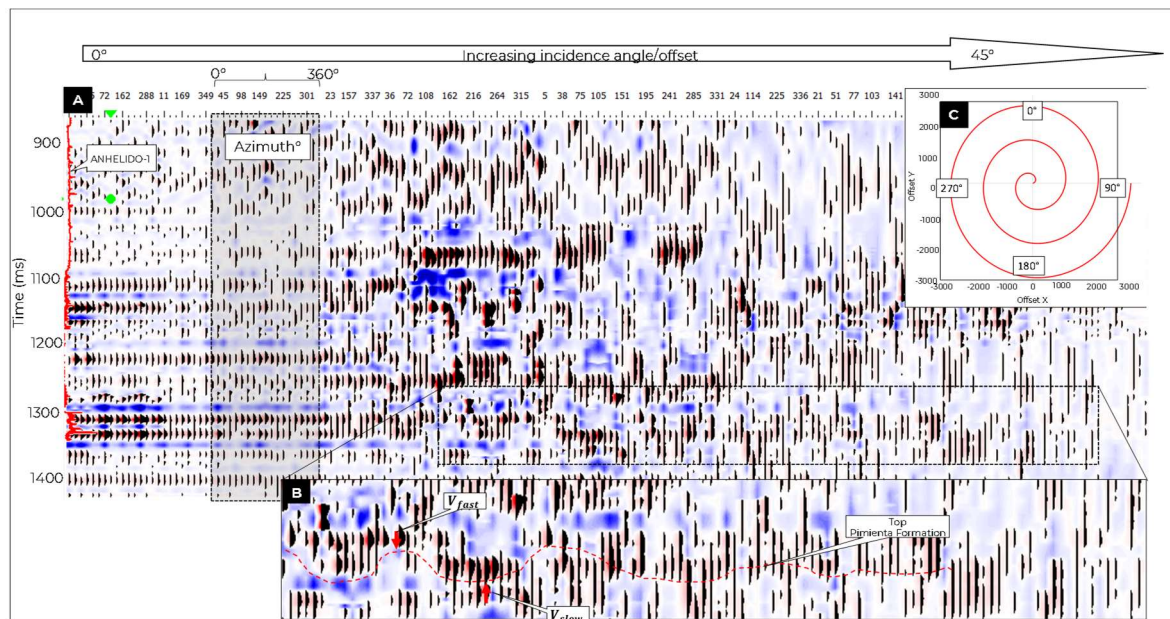


Figure 5.9 (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Anhelido-1 (trace 11451); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within the Pimienta Formation; (C) Snail gather representation (Source: CGG University training material).

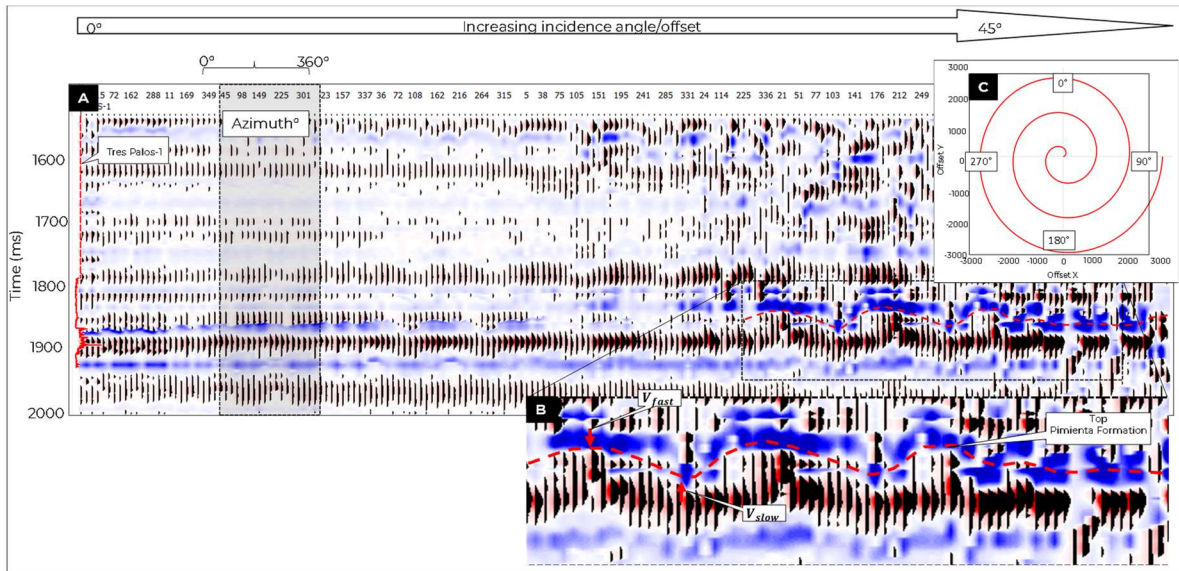


Figure 5.10 (A) Individual CDP azimuthal seismic gather sorted as common azimuth common angle (COCA) at Tres Palos-1 (trace 12101); (B) Close-up of mid to far angles of incidence and azimuths showing the wobbling effect (V_{fast}/V_{slow}) due to anisotropy within the Pimienta Formation; (C) Snail gather representation (Source: CGG University training material).

The calculations of these attributes were focused within the Pimienta Formation so the information for these attributes (e.g., anisotropic gradient and azimuth) were constrained with information from Well logs (e.g., P-sonic, S-Sonic and density) resulting in a more precise calculation which will be addressed in the results section of this chapter.

For the horizontal wells Anhelido-1 H and Serbal-1H, the velocity behaviour was analyzed in an anisotropic way for each of the stages in the horizontal section of the well. For example, each stage is assigned to (Inline/Xline) and at a certain time within the Pimienta Formation. The fast and slow velocity were estimated as well as the azimuth of the fast shear (S-wave splitting), this analysis is known as VVAz which can be performed in ProAZ module in Hampson and Russell software package.

5.2.2 Microseismic monitoring (Analogue well within Pimienta Formation)

Microseismic uses fracturing or water-injection that induced the phenomena of micro seismicity very similar to earthquakes with very low degree of intensity when the reservoir is treated under fracturing during the injection of water by monitoring the fracture behavior and the fluid flow of oil/gas (Zou, 2017). This technique is widely used in unconventional reservoirs to better understand the fracture behavior during the fracture treatment.

It can provide information of the fracture characteristics as geometries, length, height, and its orientation and is an effective means of the performance of induced fracturing in real time.

Small earthquakes are induced in microseismic monitoring by hydraulic treatment in unconventional reservoirs which pressurize the rock. The microseismic monitoring well is set with a geophone offset arrangement a few meters apart from the injection well, such that the hydraulic treatment can be recorded as an array of microseismic tremors.

The microseismic energy travels farther if the rock is tight and rigid and at greater distances more microseismic events can be recorded with downhole telemetry (Warpinski, 2009) (Figure 5.11)

Microseismic is very important to reduce the cost of stimulation and can help to improve drilling plans and fracture design. In this project, I have used information provided by PEMEX/Schlumberger from an analogue well (referred to here as Well-1) located in the North of Mexico as shown in Figure 5.12. This well was fracked with 11 stages of induced fracture treatments within the Pimienta Formation.

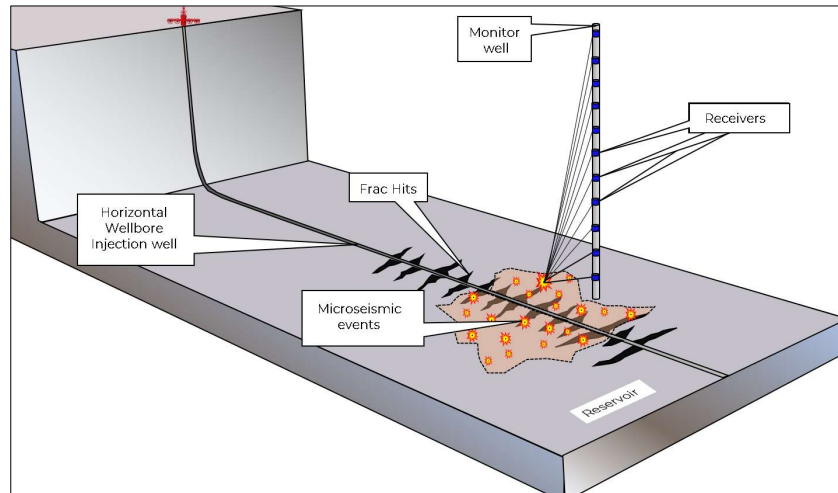


Figure 5.11 Microseismic downhole geophone array receiving seismic events (modified from Rodvelt, 2014).

Micro-seismic events can be related to different sources (faults, hydraulic fractures). In this Well-1, it was possible to identify micro-seismic events from various sources: possible natural fractures and hydraulic fractures.



Figure 5.12 Location at Well-1, Well-1H, and monitor well for microseismic survey

Figure 5.13 shows the positioning of the tool (Well monitor) which due to mechanical limitations was placed 85m above the horizontal well path. This favoured the detection of events related to the Taraies Formation directly above the Pimienta Formation. The separation from near to far stages is also seen.

This technology follows a workflow with its components below. In this section, I will focus on the interpretation of microseismic events within the Pimienta and Taraies formations.

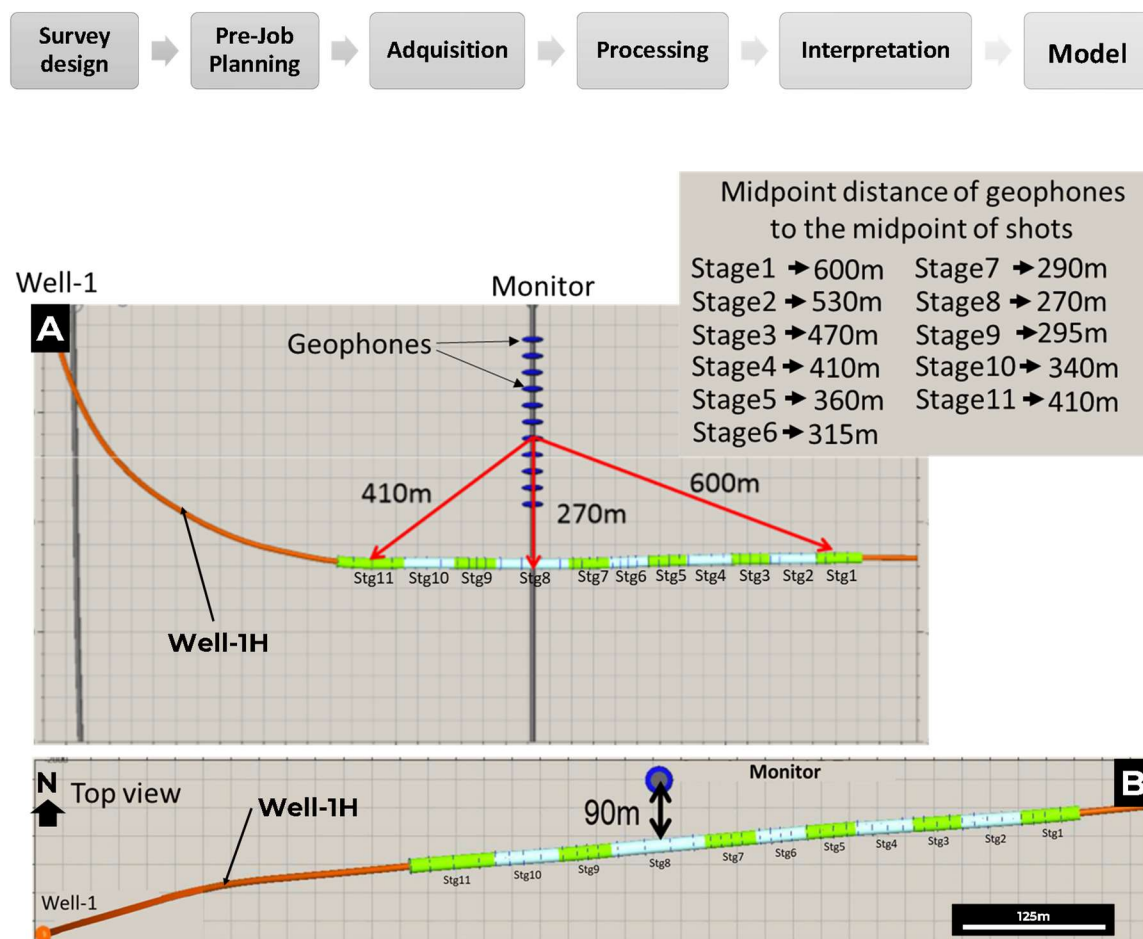


Figure 5.13 Configuration of monitor Well-1 and Well-1H for microseismic technology. Note: there are 11 hydraulic stages in horizontal section within the Pimienta formation with $\sim 91^\circ$ Dip and azimuth $\sim 85^\circ$, a total length of 1060m and 11 geophones to monitor well treatment. The distance from the horizontal side to the monitor well is 90m apart; (A) Lateral view of horizontal side of Well-1H; (B) Top view of horizontal side of Well-1H.

The scale of magnitude of a seismic event is logarithmic: an increase of one unit means an increase of 10 times the amplitude of the seismic wave or an increase of 32 times the energy radiation. The larger magnitudes may occur on larger faults (a few meters to 100s meters) which are in the range of 1-50Hz (low frequency). Microseismic information is a valuable tool for the assessing of the hydraulic fracture stimulations. During a stimulation treatment, monitor borehole with geophones record passive seismic data (Shemeta et.al., 2010).

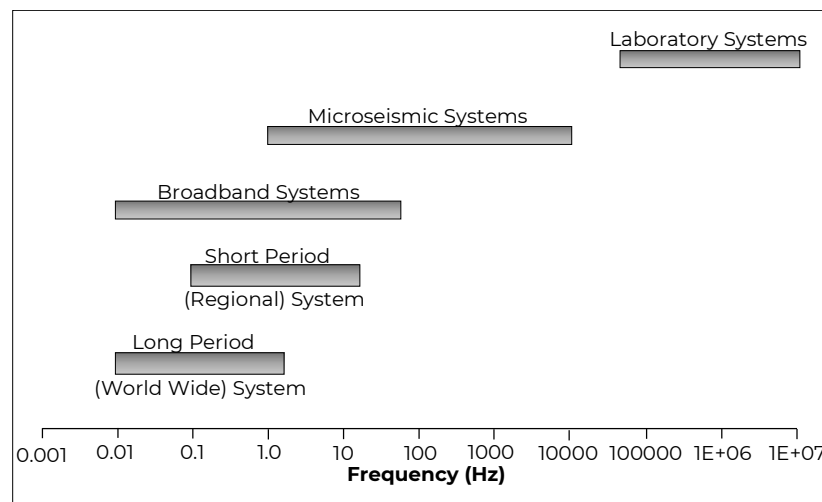


Figure 5.14 Scale of seismic events and bandwidths of various seismic systems (modified from Baig and Urbancic, 2010).

The benefits of data processing of automated events location are:

Continuous spatial mapping

Continuous spatial mapping

- Continuous spatial mapping
- No time Picking
- Locate >20 events per minute
- Uses noise reduction power array
- Locate more events than conventional methods

A substantial micro-seismic activity was detected handled in StrimMAP Schlumberger software package, with good quality events, and magnitudes between -2.5 and 0.5; and a signal-to-noise ratio of 5 to 80 (Figure 5.15).

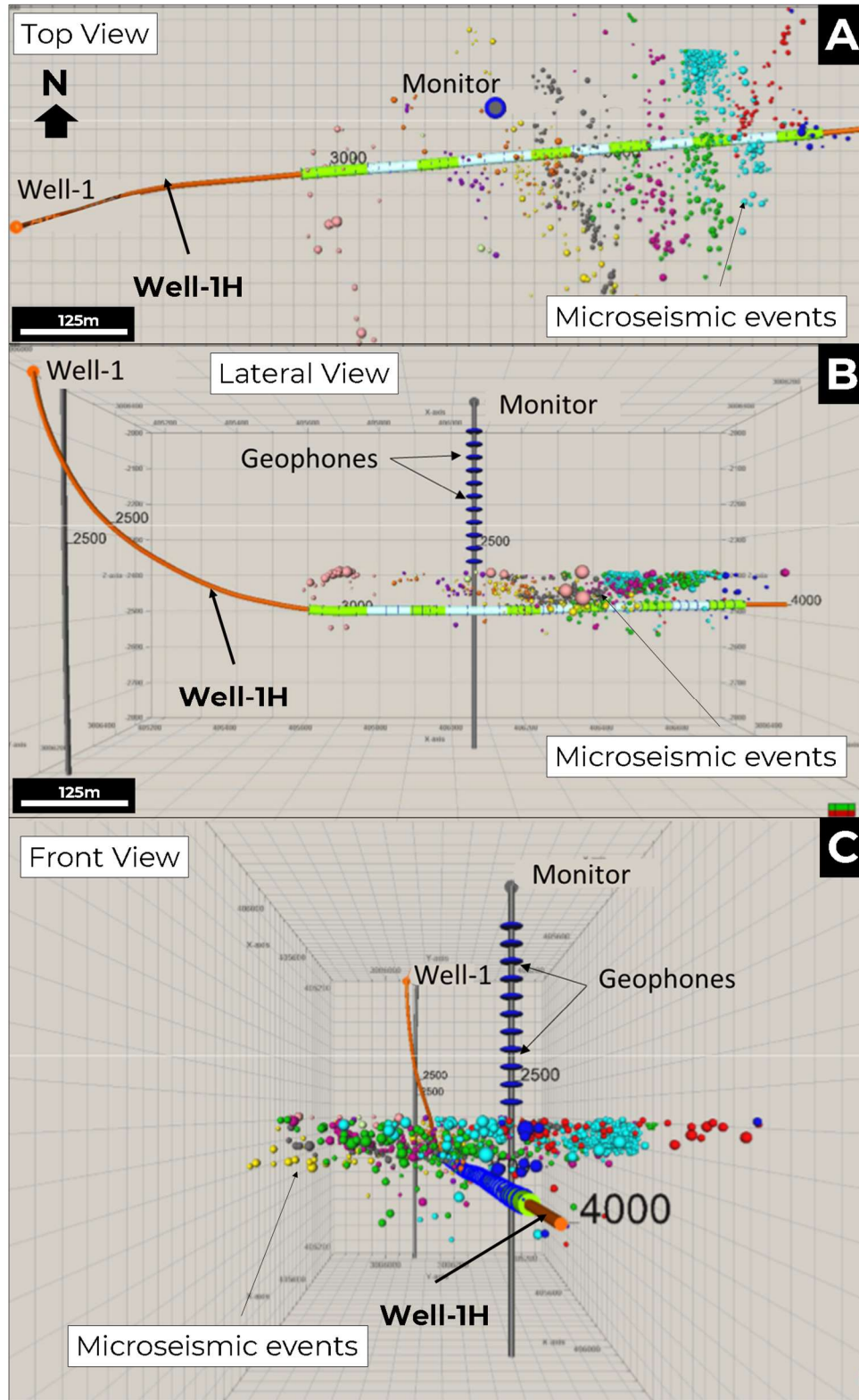


Figure 5.15 Microseismic events at Well-1H within the Pimienta Formation, the events are coloured by stage and sized by energy and related to the hydraulic stage; (A) Top view of horizontal side of Well-1H; (B) Lateral view of horizontal side of Well-1H; (C) Front view of horizontal side of Well-1H.

In Well-1 and Well-1H, it was possible to identify micro-seismic events from two sources: possible natural fractures and artificial hydraulic fractures.

5.2.2.1 Structural attributes and AVAz

Fracture attributes are designed to reveal discontinuities that may or may not be indicative of fracturing or faulting. The attributes can be computed using different approaches but, in this study, I employed Ant-tracking. This is a structural volume attribute which is patent-protected technology from Schlumberger company. This attribute can enhance fractures, faults and discontinuities that can be present in a 3D seismic survey (Pedersen et.al., 2002).

The Ant Track attribute lets the user exclude orientations from the output volume. This is especially helpful for separating fault systems that overlap and for removing an acquisition or data processing footprint from edge data. The objective is to generate an enhanced edge volume to use in combination with the seismic volume for accurate fault mapping.

To perform an effective ant attribute, the set of 3D seismic data was used with area of 30Km² around the Well-1 and Well-1H mentioned in section 5.2.2 which was conditioned using other structural attributes (e.g., structural smoothing) to remove unwanted background noise.

The attributes estimated to obtain the 3D ant tracker volume followed a workflow (Figure 5.16) designed to enhance the possible faults present within the Pimienta Formation in this seismic data set:

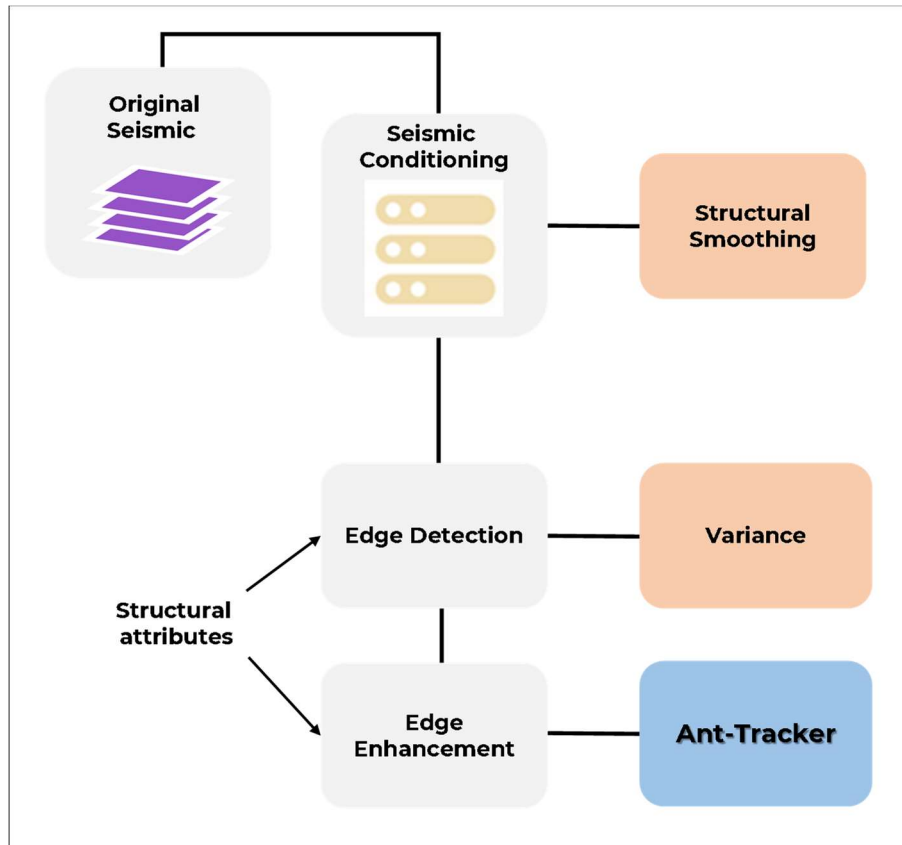


Figure 5.16 Workflow to obtain Ant-Tracker attribute for fault detection in the study area around Well-1 and Well-1H.

- The first step was the data conditioning to improve the seismic image by reducing noise.
- Application of a structural filter for smoothing the seismic data estimation of structural attributes for edge detection on seismic data such as the volume of variance or coherence.
- Finally, the edge enhancement attribute estimation known as Ant-tracker.

In Figure 5.17 shows the process applied to the seismic data of the area around the Well-1 and Well-1H listed in the points addressed above.

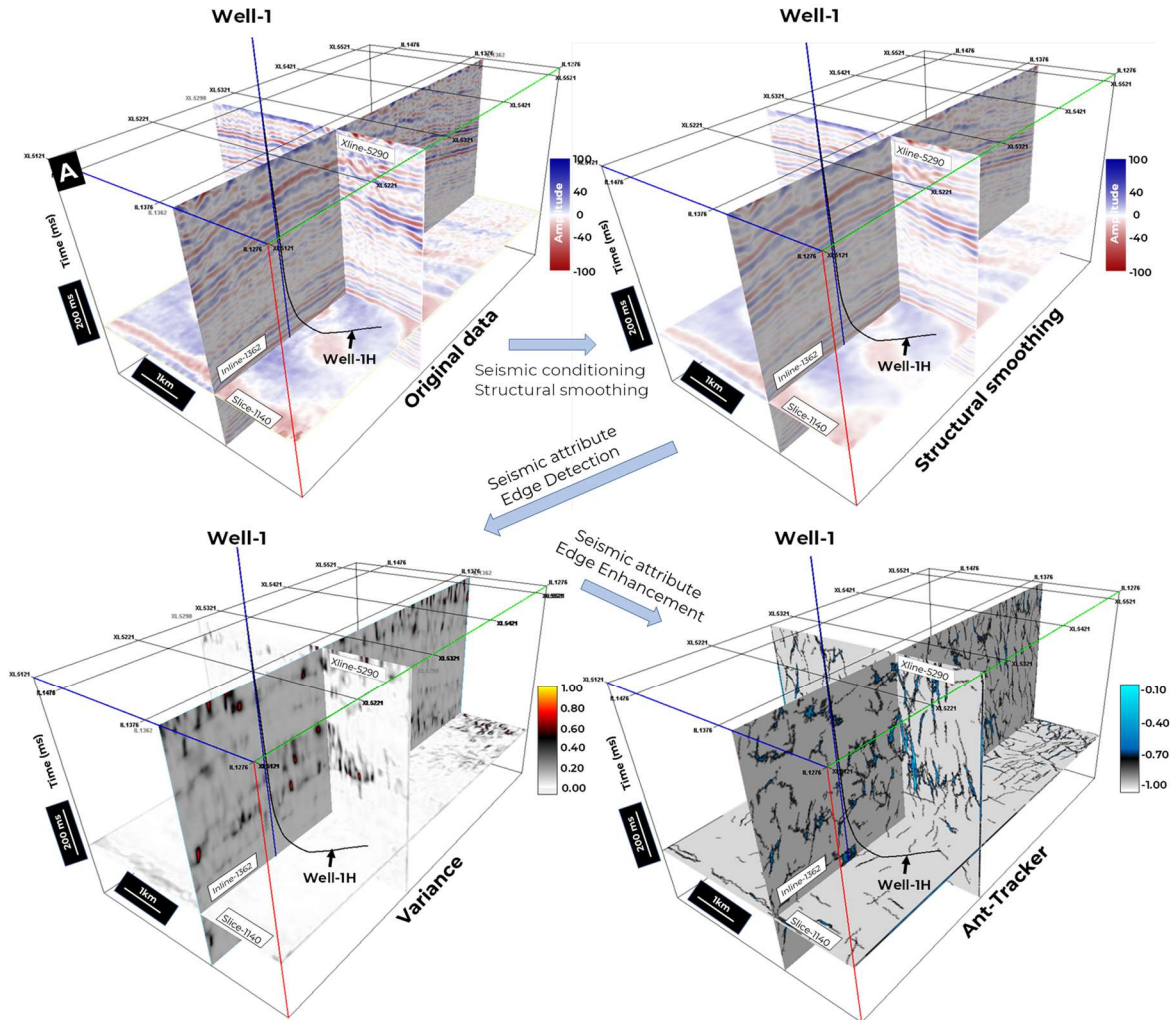


Figure 5.17 Workflow for the estimation of the Ant-tracker attribute at Well-1 and Well-1H location (inline-1362, xline-5209); (A) Original seismic data Pre-Stack Time Migration (PSTM); (B) Structural smoothing data conditioning; (C) Edge detection attribute known as variance or coherence; (D) Edge enhancement attribute Ant-tracker.

5.2.3 DEM approach and detailed comparison with the literature on shale modelling.

Differential Effective Medium theory allows the calculation of elastic properties (namely bulk and shear moduli) of composite media. This theory "constructs" the model as a background solid medium with added ellipsoidal inclusions. The inclusions are added in an interactive manner to avoid violating the Kuster and Tuksoz (1974) premises.

DEM is widely used for estimating wave-velocity in porous media. For example, Xu and Payne (2009) proposed a rock physics model for calculating wave velocities in carbonates, extending the model proposed by Xu and White (1995). Both models use DEM theory.

The impact of fraction volume kerogen and total organic contents (TOC) on the seismic data response of organic-rich shale has received more attention (Aziz et al., 2018). Several researchers tried to model the impact of these parameters on shale's seismic properties with the rock physics model (Carcione et al., 2011; Vernik & Milovac, 2011; Li et al., 2015; Aziz et al., 2018). Zhu et al. (2012) suggested an improved rock physics model for shale plays. The impact of the fraction volume of kerogen on the anisotropy of shales was carried out by Sayers (2013).

A significant impact of volume fraction of kerogen on seismic properties is due to its low density (Passey et al., 2010). Three essential components: solid organic matter, void space, and rock matrix comprise the organic shale rock, while non-organic rocks are composed of the void space and rock matrix. In Figure 5.18 is shown the diagram of organic shale rock with different maturity levels.

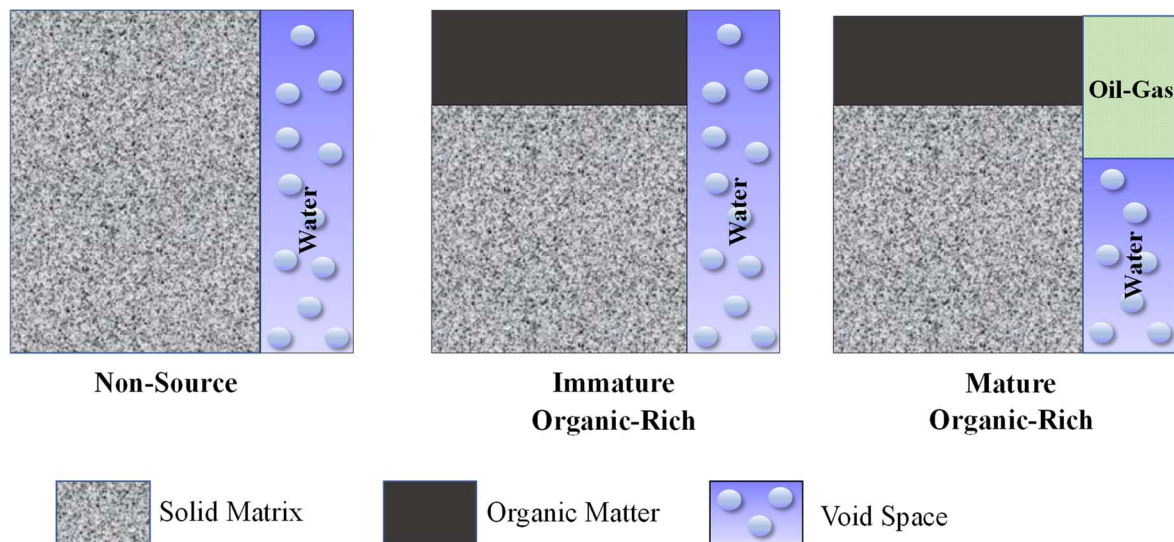


Figure 5.18 Diagram of organic shale rock

The solid organic matter is converted into gas or liquid hydrocarbons by time and temperature (catagenesis). The gas or liquid hydrocarbons migrate into the void space displacing the formation water or increasing the saturation of formation fluids. This displacement of pore fluid by hydrocarbon fluids has a significant effect on density, porosity and resistivity in the Pimienta Formation, which are reflected in the well log response (Passey et al., 2010).

The computation of vitrinite reflectance and level of maturity is addressed in Chapter 3 section 3.4 where information from RockEval was used to estimate the TOC using Passey's method.

The combination of volume kerogen fraction and the TOC impact on seismic data is still a subject of active research and needs to be investigated further. Here I analyzed the effect of kerogen fraction and TOC on seismic data properties of the shale reservoir within the Pimienta Formation in comparison with the research work reported by Vernik and Liu (1997) in the Bakken Shale with the elastic stiffness coefficients at (70MPa) versus kerogen content computing from bedding-parallel and bedding-normal ultrasonic P-velocity measurements.

The content of organic matter in shales has specific density, resistivity and radioactivity values that influence on well-log and seismic responses (Zhu et al., 2011). Thus, logs and seismic can characterise shale oil/gas reservoirs.

Rock physics provides an essential link between various microscopic and macroscopic physical properties of rocks and fluids (Das et al., 2018). Rock physics modelled is used to quantify the effect of volume of kerogen, porosity, and TOC on seismic properties of organic-rich Pimienta Formation shale. The mixture of kerogen and hydrocarbon-filled pores is assumed to have a non-zero shear modulus (Passey et al., 1990).

The effective medium DEM theory proposed by Kuster and Toksöz (1974) has been used to calculate the elastic moduli of mixture (oil, gas, kerogen, and water) and the organic shales. S_k , S_o , S_g and S_w are the saturation of kerogen, oil, gas, and water respectively. The K_{ogw} represent the bulk modulus of the mixture (oil/gas/water) which is calculated using the equation addressed by Wood (1931). The mineral fraction and gamma ray information within Pimienta Formation are presented in Figure 5.19.

$$K_{ogw} = \left[\frac{S_o}{K_o} + \frac{S_g}{K_g} + \frac{S_w}{K_w} \right]^{-1} \quad (5.3)$$

Where

K_o – Bulk moduli of oil

K_g – Bulk moduli of gas

K_w – Bulk moduli of water

For the estimation of the elastic parameters, Bulk modulus, Shear Modulus and Poisson's Ratio are given by the following relationship of P-wave, S-wave velocities, and density from log data:

$$\mu = \rho * V_s^2 \quad (5.3)$$

$$K = \rho * \left(V_p^2 - \frac{4}{3} V_s^2 \right) \quad (5.4)$$

$$v = \frac{1}{2} \left[\frac{\left(\frac{V_p}{v_s} \right)^2 - 2}{\left(\frac{V_p}{v_s} \right)^2 - 1} \right] \quad (5.5)$$

	Bulk Modulus (GPa)	Shear Modulus (GPa)	Density(g/cc)
Calcite	77	32	2.71
Quartz	37	43	2.65
Clay	21.5	9	2.5
Dolomite	95	45	2.85
Kerogen	6.8	2.02	1.4
Oil	0.6	0	0.7
Gas	0.06	0	0.12
Water	2.25	0	1.04

Table 5.1 Elastic properties of different constituents of shale gas reservoir used in rock physics modelling modified (Mavko et al., 2009) within the Pimienta Formation.

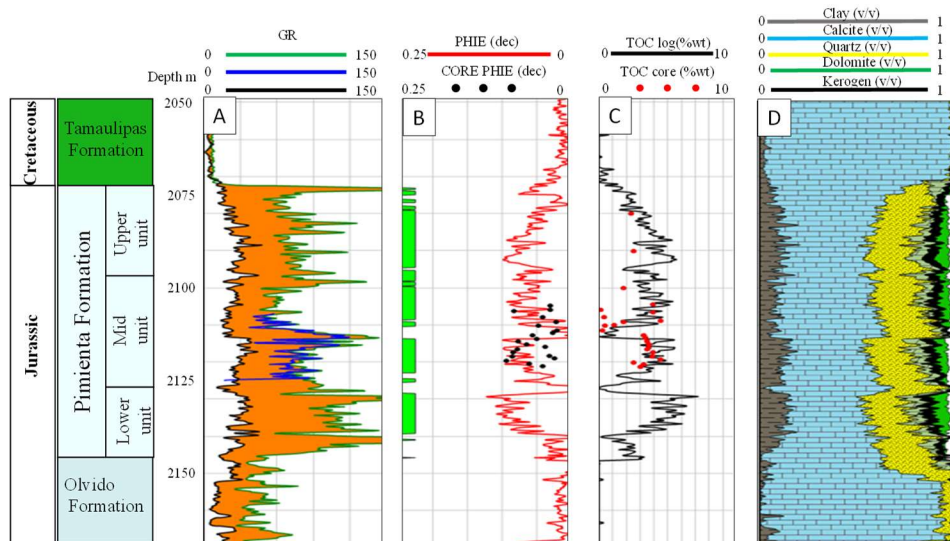


Figure 5.19 Petrophysical evaluation within Pimienta Formation; A) Gamma ray log (black) with no radioactive components Uranium (U), Thorium (Th), and Potassium (K), the Gamma ray log (green) with radioactive components (U), (Th), and (K), the core Gamma ray (blue) with its radioactive components (U), (Th), and (K); B) Effective porosity log(red) and core porosity (black dots); C) TOC log (black) and TOC samples from RockEval (red dots); D)Mineral proportions including kerogen fraction (black).

The TOC effect and the fraction of kerogen on the elastic properties such as Poisson's Ratio, Bulk Modulus, and Shear modulus of shale Pimienta Formation a 3D scatter data is plotted as a function of TOC and volume fraction of kerogen shown in Figure 5.20 using Plotly python library online and MATLAB. The relationship between Vp and TOC is inverse according to the 3D scatter data. P-wave velocity reduces in organic-rich shale intervals as compared to non-organic shales. The correlation between TOC and quartz fraction contents in the organic shale Pimienta Formation seems inverse, whereas a positive correlation between TOC and the clay content is noted; high volume clay and low velocity represent high values in TOC (Figure 20A). Thus, the dependency of seismic velocities increases with an increase in stiffer quartz fraction and decreases with increase in clay contents as confirmed by Zhu et al. (2012) (Figure 20B).

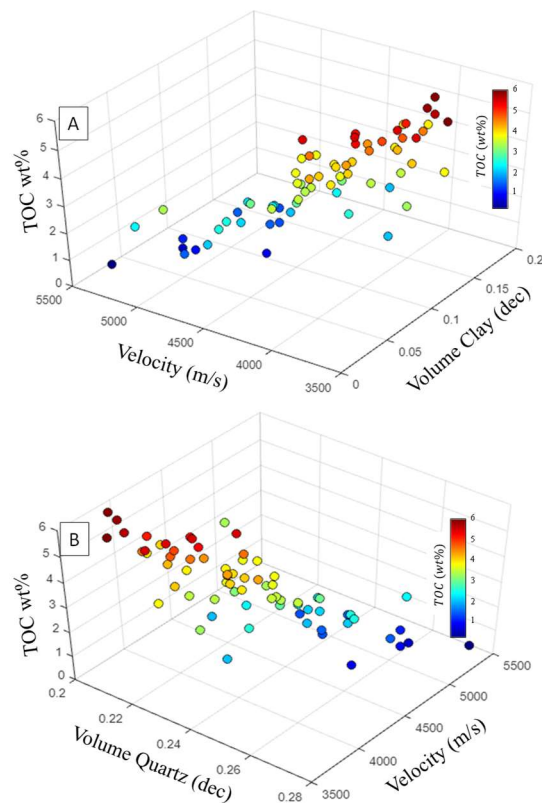


Figure 5.20. Relationship between TOC, P-wave velocity, the volume fraction of quartz and clay in 3D scatter data within Pimienta Formation; A) Velocity decreases with high clay fraction and high TOC; B) Velocity increases with high quartz fraction and low TOC content.

Bulk modulus and shear modulus indicate the elastic behavior of the reservoir rock. The bulk and shear modulus of the Pimienta Formation shales also have an inverse relation with TOC content. Low values of bulk modulus represent high TOC and relatively high porosity contents within the Pimienta Formation (Figure 5.21)

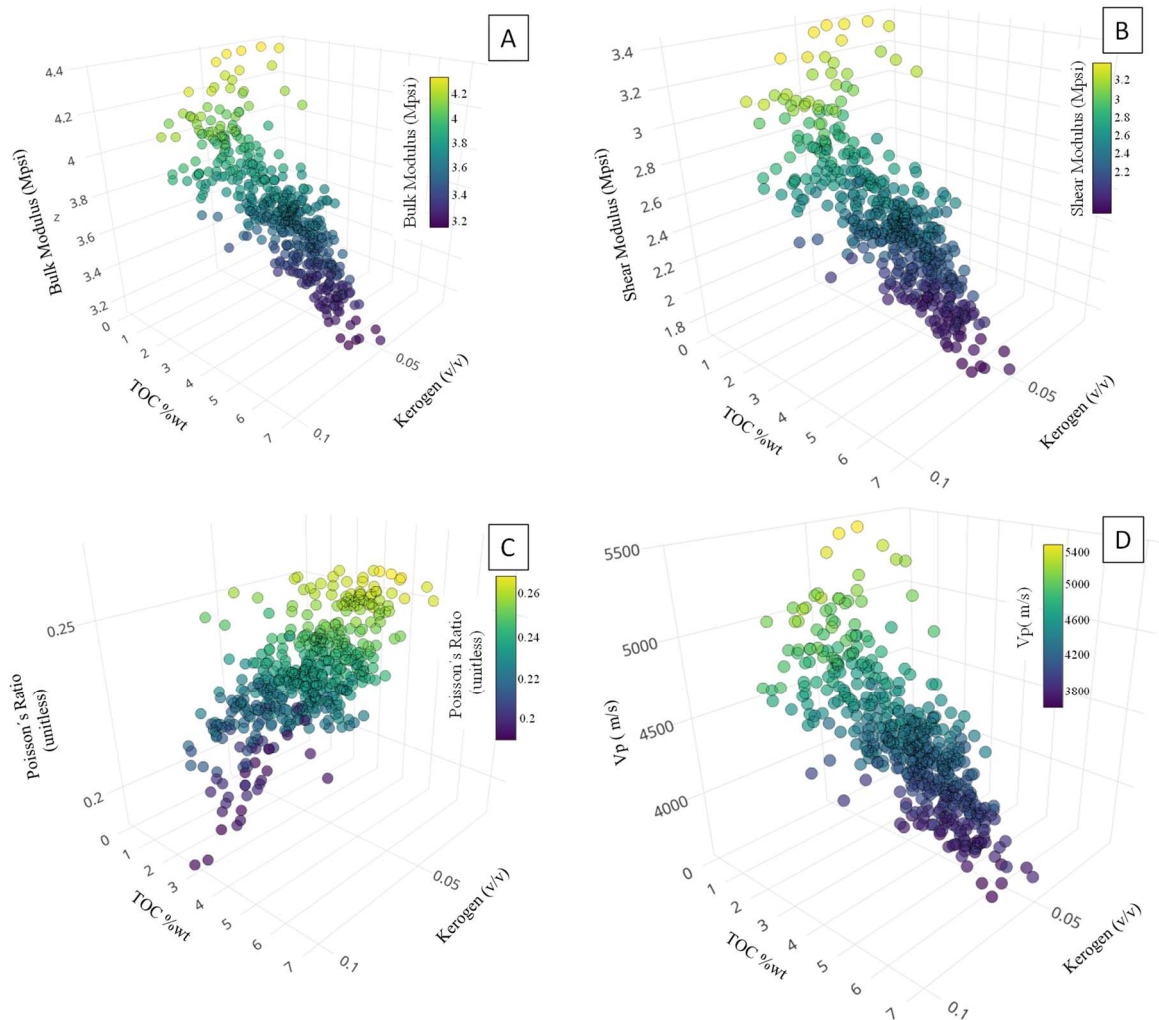


Figure 5.21. Effect of volume fraction of kerogen and TOC on A) Bulk Modulus; B) Shear Modulus of incompressibility; C) Poisson's ratio of Organic-Rich shale within Pimienta Formation encountered at 2074-2145m depth in Anhelido-1.

Recent research on unconventional resources has demonstrated that organic shales have an impact that is found to be strongly anisotropic due to the partial alignment of anisotropic clay minerals and the bedding-parallel lamination of organic material within the shale (Vernik and Nur, 1992; Vernick,

1993, 1994; Vernik and Landis, 1996; Vernik and Liu, 1997; Sondergeld et al., 2000; Sondergeld and Rai, 2011). In their research, these authors investigated the effects of kerogen on seismic anisotropy modelling the Organic-Rich shale as a 1D layered medium consisting of layers of shale and kerogen (Vernik and Nur, 1992; Vernik and Landis, 1996; Vernik and Liu, 1997). In their model, Vernik and Landis (1996) assumed that kerogen could be treated as isotropic, whereas shale is assumed to be transversely isotropic (VTI) with an axis of rotational symmetry oriented perpendicular to the layers. Figures 5.22 and 5.23 show the relationship between elastic stiffness coefficients (C_{11} , C_{33} , C_{55} and C_{66}) and kerogen fraction within the Pimienta Formation described below:

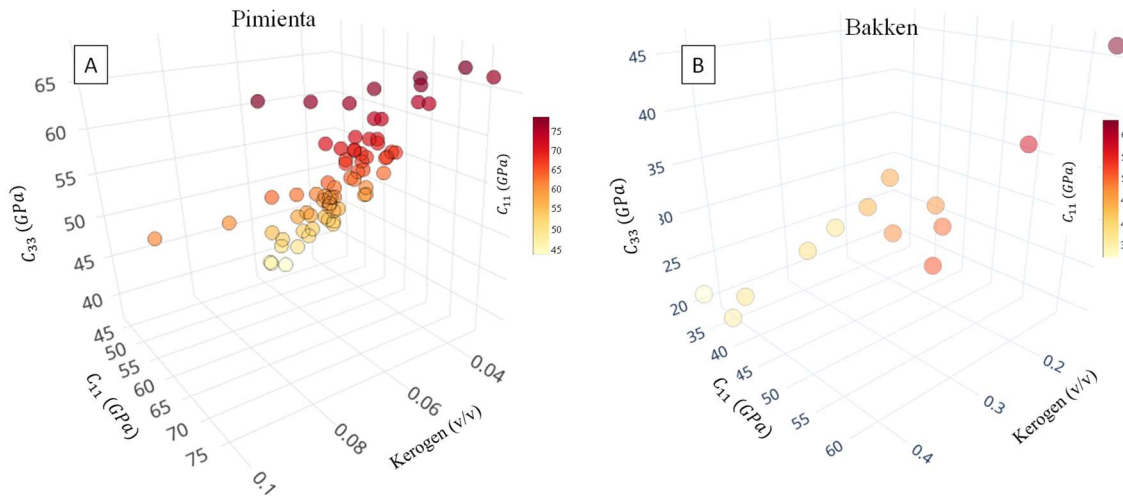


Figure 5.22 Relationship between elastic stiffness coefficients (C_{11} and C_{33}) and kerogen fraction; A) Impact on kerogen fraction as a function of (C_{11} and C_{33}) within the Pimienta Formation B) Impact on kerogen fraction as a function of (C_{11} and C_{33}) on the Bakken Shale suggesting the same behaviour.

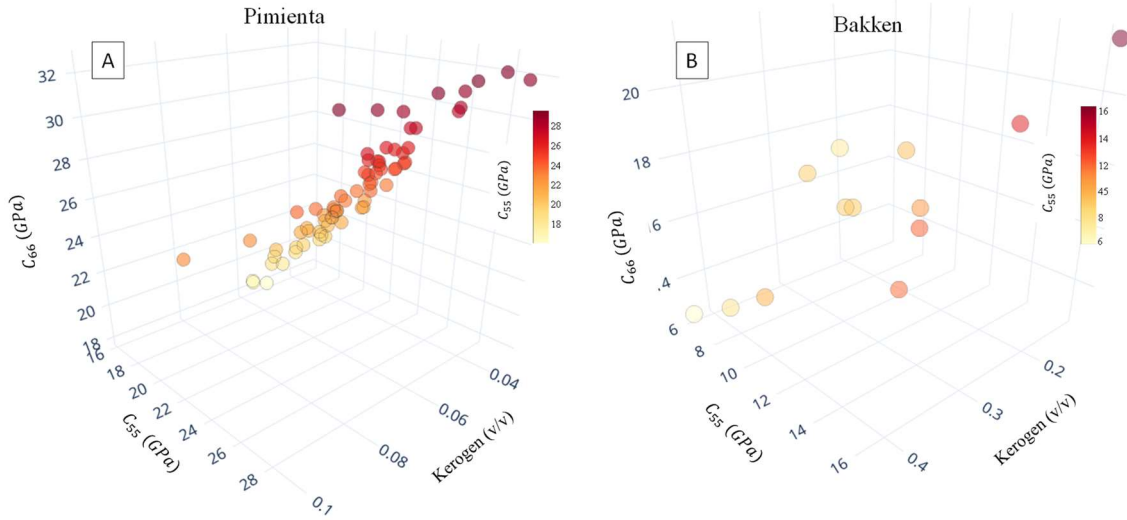


Figure 5.23 Relationship between elastic stiffness coefficients (C_{55} and C_{66}) and kerogen fraction; A) Impact on kerogen fraction as a function of (C_{55} and C_{66}) within the Pimienta Formation B) Impact on kerogen fraction as a function of (C_{55} and C_{66}) on Bakken Shale suggesting the same behaviour.

To establish a relationship of elastic stiffness coefficients within the Pimienta Formation, a comparison with the research work reported by Vernik and Liu (1997) in the Bakken Shale with the elastic stiffness coefficients (C_{11} , C_{33} , C_{55} , and C_{66}) at (70MPa) versus kerogen content computed from bedding-parallel and bedding-normal ultrasonic P-velocity measurements have been made in this thesis project.

The average ranges of elastic coefficients (C_{11} , C_{33}) within the Pimienta Formation are 58 and 50 GPa, respectively, (C_{55} , and C_{66}) are 21 and 24 GPa, according with the Figures 5.22 and 5.23 these coefficients have a substantial impact depending on the kerogen fraction content suggesting that the elastic coefficients in the Pimienta Formation are inverse to the kerogen content. In contrast, the research addressed by Vernik and Liu (1997) in the Bakken Shale suggests that the elastic constants decrease with higher kerogen content according with the average values of C_{11} , C_{33} which round 45 and 28 GPa respectively and 10 and 16GPa for (C_{55} , C_{66}), confirming the same behavior for the Pimienta Formation (Figure 5.24). This is an important finding when it is considered that in the Pimienta Formation the mineralogical content is mostly calcite and quartz (Figure 5.19D), and this would also have an impact on high values of the elastic coefficients.

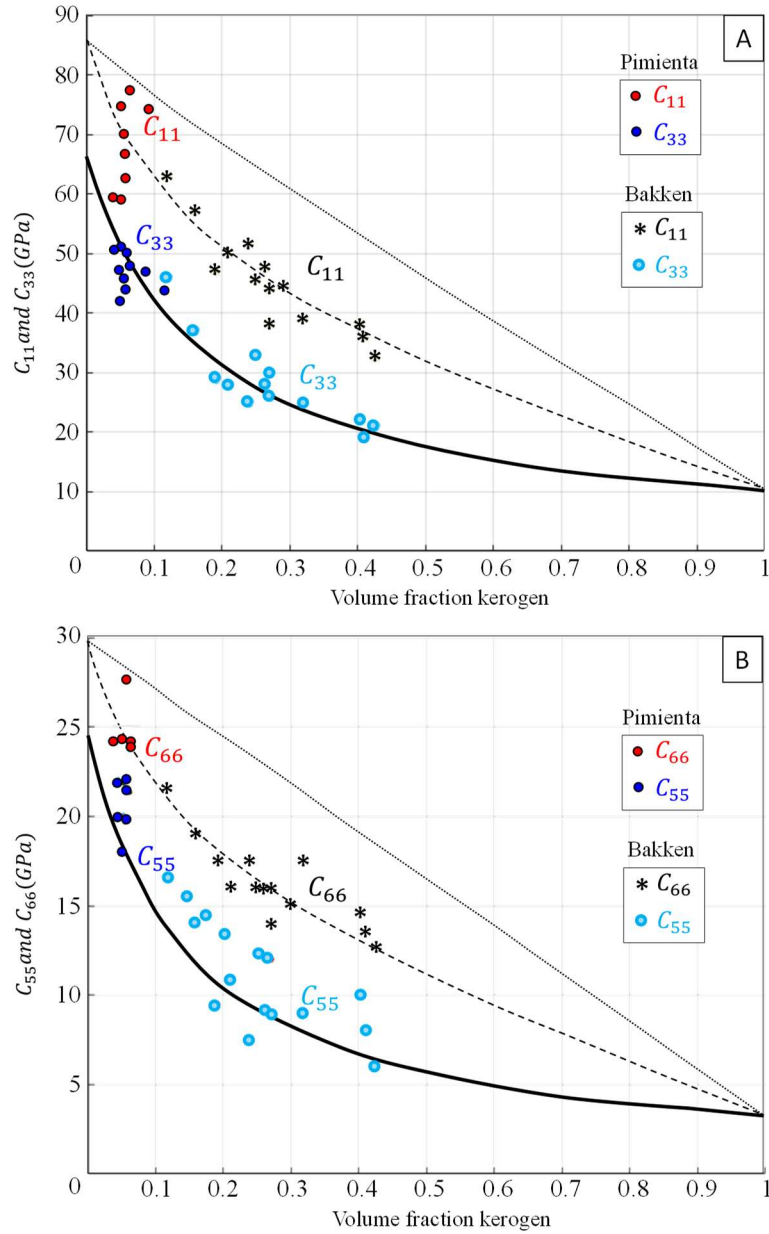


Figure 5.24 A) Elastic stiffness coefficients C_{11} (stars) and C_{33} (blue light points) computed from bedding-parallel and bedding-normal ultrasonic P-velocity measurements reported by Vernik and Liu (1997) in Bakken shale at high confining pressure (70 MPa) versus kerogen content and stiffness coefficients within Pimienta Formation using ultrasonic measurements from log data P-velocity C_{11} (red points) and C_{33} (blue points); B) Elastic stiffness coefficients C_{66} (stars) and C_{55} (blue light points) computed from bedding-parallel and bedding-normal ultrasonic P-velocity measurements reported by Vernik and Liu (1997) in Bakken shale at high confining pressure (70 MPa) versus kerogen content and stiffness coefficients within Pimienta Formation using ultrasonic measurements from log data P-velocity C_{55} (red points) and C_{66} (blue points).

As an alternative approach, a number of studies have employed the DEM scheme (e.g., Hornby et al., 1994; Draege et al., 2006; Vasin et al., 2013). The DEM scheme assumes that hypothetical ellipsoidal inclusions with known aspect ratio distribution are presented and account for the rock's total porosity. The assumption of ellipsoidal penny-shaped pore geometry (see Chapter 4.2.1) makes this model quite controversial due to the elastic inclusion (e.g., Berryman, 1980; Kuster and Toksöz, 1974). This may lead to an inaccurate representation of the rock shale microstructure. However, its microcrack-density parameter does at least offer physics-based approach and any drawbacks can be outweighed by the unrealistic premise about those aspects of pore geometry which represent real limitations. Figure 5.25 shows different model approaches for the estimation of P and S-wave velocities within organic shale rock applied in the Pimienta Formation (Hu et al., 2015; Vernik and Kachanov, 2010).

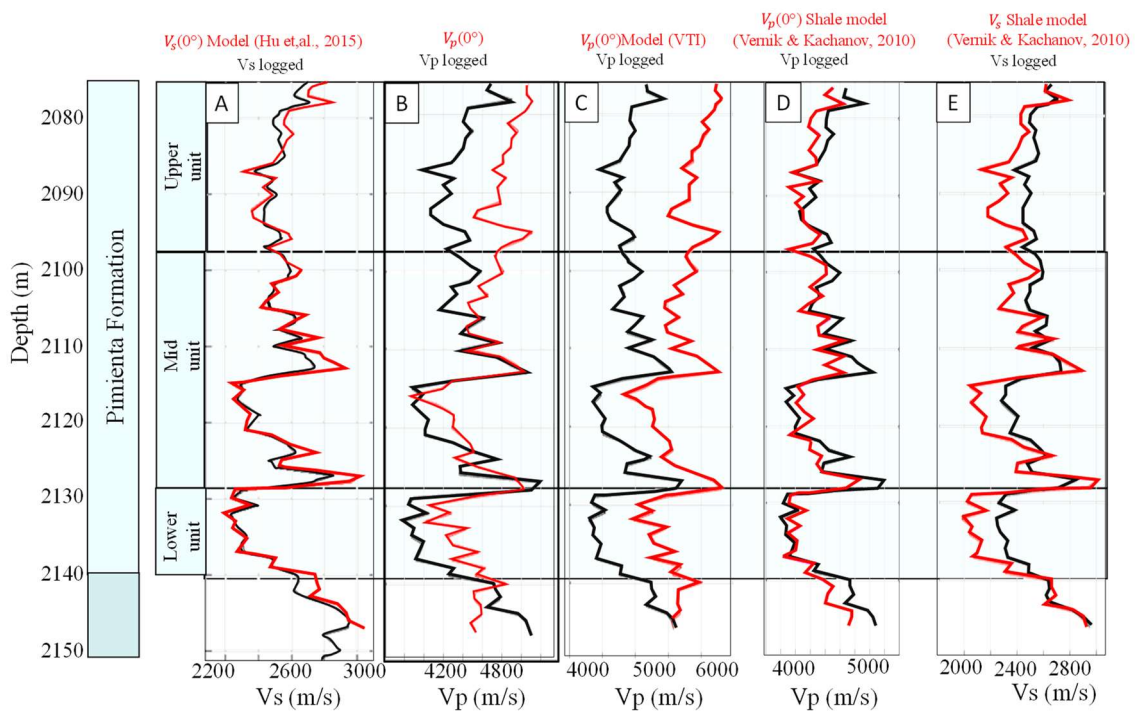


Figure 5.25 Vertical P and S-wave velocity logs (black) within Pimienta Formation at Anhelido-1 with different model approach.

Another limitation is that the effect of pore geometry is difficult to estimate from the seismic velocity and porosity of the rock. The modelling of elastic inclusion relates moduli to porosity through an equivalent aspect ratio; in most cases, it fails. In contrast, empirical relations are often hard to extrapolate beyond their range of validity, often leading to incorrect results at high and low porosities.

However, this model was applied to the reservoir zone within the Pimienta Formation since it is the first time it has been carried out on this geological formation in the study area.

The bulk K_{dry} and shear modulus μ_{dry} are estimated using the DEM analytical model (eqs. 5.6-5.14).

The parameters of this model are elastic moduli of the solid matrix, porosity (ϕ), and pore aspect ratio (α). K_m and μ_m of the solid matrix were computed using mineral components of the rock XRD data.

$$K_{dry} = K_m \frac{(1 - \phi)S_0 \left[S_1 + S_2 + S_3 + \left(\frac{(S_1 - S_3)(S_2 - S_3)}{S_3 + \left(\frac{K_m}{\mu_m} \right)} \right) \right]}{\left[1 + \frac{bK_m}{a\mu_m} - \frac{bK_m}{a\mu_m} (1 - \phi)^a \right]^{\frac{S_0}{b}}} \quad (5.6)$$

$$\mu_{dry} = \mu_m \frac{(1 - \phi)S_0 \left[S_1 + S_2 + S_3 + \left(\frac{(S_1 - S_3)(S_2 - S_3)}{S_3 + \left(\frac{K_m}{\mu_m} \right)} \right) \right] - a}{\left[1 + \frac{bK_m}{a\mu_m} - \frac{bK_m}{a\mu_m} (1 - \phi)^a \right]^{\frac{S_0}{b} - 1}} \quad (5.7)$$

$$S_0 = \frac{2 - 3g - 3\theta}{2(2\theta - 3\theta^2 - 2g)} \quad (5.8)$$

$$S_1 = \frac{\theta - g}{2 - 3g - 3\theta} \quad (5.9)$$

$$S_2 = \frac{4}{3} \quad (5.10)$$

$$S_3 = \frac{2(\theta - g)}{3(2\theta - 3\theta^2 - 2g)} \quad (5.11)$$

$$\theta = \begin{cases} \frac{\alpha}{(1 - \alpha^2)^{3/2}} [\cos^{-1}(\alpha) - \alpha\sqrt{1 - \alpha^2}] & (\alpha < 1) \\ \frac{\alpha}{(1 - \alpha^2)^{3/2}} [\alpha\sqrt{\alpha^2 - 1} - \cosh^{-1}(\alpha)] & (\alpha > 1) \end{cases} \quad (5.12)$$

$$g = \frac{\alpha^2}{1 - \alpha^2} (3\theta - 2) \quad (5.13)$$

$$P^{*i} - Q^{*i} = a + b \left(\frac{K^*(y)}{\mu^*(y)} \right) \quad (5.14)$$

Bulk and shear modulus are K_{dry} and μ_{dry} , respectively. K_m and μ_m are the mineral matrix moduli, ϕ is the porosity, a is estimated from eq 5.14 where $\frac{K^*}{\mu^*} = \frac{K_m}{\mu_m}$ is placed, b is the first derivative of $P^{*i} - Q^{*i}$, the pore aspect ratio is represented by α (See Appendix A of Li and Zhang (2011) to verify the calculation of $P^{*i} - Q^{*i}$ and its derivatives). The DEM model is favourable for the experimental conditions with high frequency. Assuming dry rock conditions and it is important to calculate then the elastic bulk and shear moduli using Gassman's model (Gassman. 1951).

Based on the follow assumption, Gassman's models work as follows:

- (1) The rock fabric is homogeneous in terms of macroscopic features.
- (2) There is an interconnection between the pores.

(3) A frictionless fluid fills the pores.

(4) The fluids are not drained.

(5) The pore fluids do not interact with the solid particles of the rocks (Adam et al., 2006). The equations of Gassmann's fluid substitution model are given below:

$$K_{sat} = K_{dry} + \frac{\left(1 - \frac{K_{dry}}{K_m}\right)^2}{\frac{\phi}{K_f} + \frac{1 - \phi}{K_m} + \frac{K_{dry}}{K_m^2}} \quad (5.15)$$

$$\mu_{sat} = \mu_{dry} \quad (5.16)$$

The fluid-saturated rock moduli are represented by K_{sat} and μ_{sat} and the bulk moduli for fluid is K_f , which is calculated using Eq 16 (Dvorkin et al., 1999):

$$\frac{1}{K_{fluid}} = \frac{S_g}{K_g} + \frac{S_w}{K_w} + \frac{S_{oil}}{K_{oil}} \quad (5.17)$$

$$K_{fluid} = S_g K_g + S_w K_w + S_{oil} K_{oil} \quad (5.18)$$

The saturations of the gas, water and oil are given by S_g , S_w , and S_{oil} respectively and K_g , K_w , and K_{oil} represent the bulk moduli then can be estimated the fluid saturated rock density using (Mavko et al. 2020):

$$\rho_{sat} = \phi \rho_f + (1 - \phi) \rho_{mat} \quad (5.19)$$

$$\rho_f = S_g \rho_g + S_w \rho_w + S_{oil} \rho_{oil} \quad (5.20)$$

$$\rho_m = \sum_{i=1}^n f_i \rho_i \quad (5.21)$$

ρ_{sat} – Density of saturated rock

ρ_f – Fluid of the rock

ρ_m – mineral matrix

ρ_g – gas density

ρ_w – water density

ρ_{oil} – oil density

Using the previous variables then can be used to estimate the V_p and V_s velocities using the next equations (Mavko et., al. 2020):

$$V_p = \sqrt{\frac{K_{sat} + \frac{4}{3}\mu_{sat}}{\rho_{sat}}} \quad (5.21)$$

$$V_s = \sqrt{\frac{\mu_{sat}}{\rho_{sat}}} \quad (5.21)$$

In this section, I introduce the DEM theory for the analysis of the bulk modulus and porosity relationship in the scatter data analysis within the Pimienta Formation (Li and Zhang, 2010) where the aspect ratio is low according to the theory (Figure 5.26). The comparison to the experiment of Walsh et al., (1965) with spherical pores and the self-consistent theory is shown in Figure 5.27 for bulk and dry shear modulus. For the DEM calculation I have developed a code GUI in MATLAB called DEMmodR1 (Appendix B.1). The result in the modelling suggests very good agreement between well-log data and the prediction log using DEM theory, high correlation is shown between V_p and V_s (Figure 5.28).

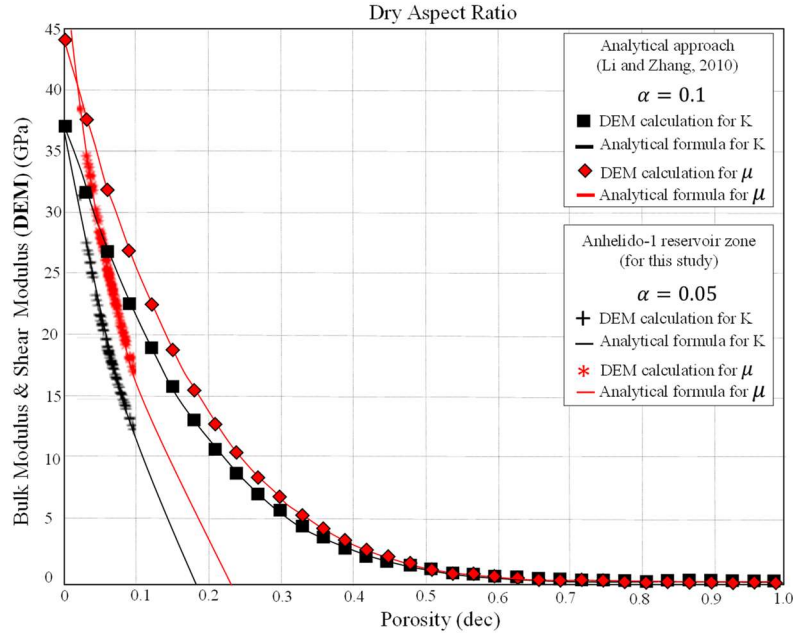


Figure 5.26 The dry-rock bulk and shear moduli for aspect ratio pores ($\alpha = 0.1$) (Li and Zhang, 2010) and aspect ratio ($\alpha = 0.05$) within the Pimienta Formation (reservoir zone); Agreement between the complete DEM calculation and the analytical formula is very good.

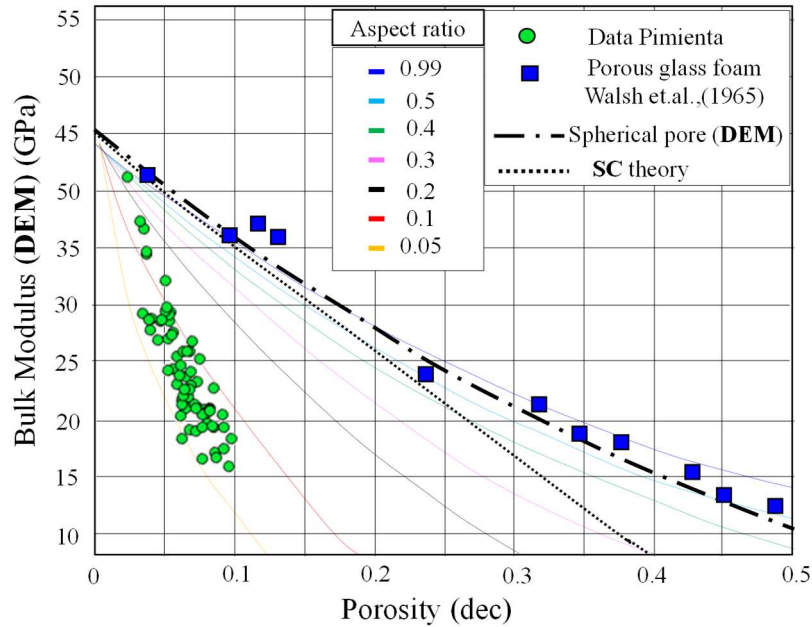


Figure 5.27 Bulk moduli of porous glass foam computed from compressibilities measured by Walsh et al. (1965). Measured values (black rectangles) are compared to theoretical predictions of DEM theory (spherical pores). The dashed line is computed from the approximate formula. The dotted (black) curve is the theoretical prediction of self-consistent theory for spherical pores, and coloured curves (are theoretical predictions of DEM theory using different aspect ratios and superposed samples of the Pimienta Formation.

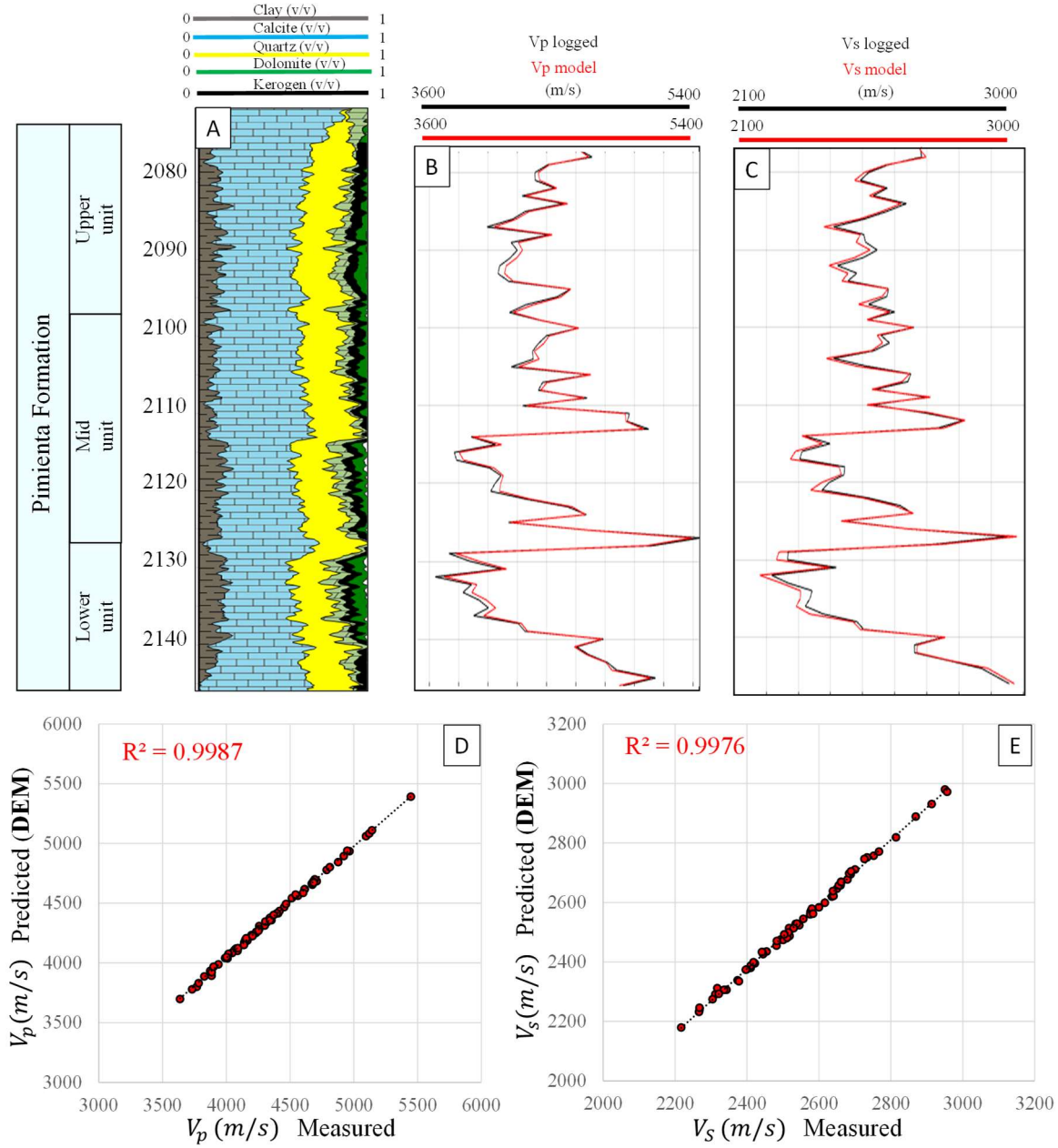


Figure 5.28. A) Minerals volume fraction; B) Vertical P -wave velocity (black) from log data measured; and V_p predicted from modelling (red) DEM analysis and Gassman's theory; B) Vertical S -wave velocity (black) from log data measured; and V_s predicted from modelling (red); D) Correlation $R^2=0.9987$ between V_p logged and V_p predicted from modelling; E) Correlation $R^2=0.9976$ between V_s logged and V_s predicted from modelling.

5.2.4 Anisotropic rock physics

Fractured shale reservoirs have been shown to be anisotropic. This anisotropy may correspond to changes in Poisson Ratio and Young's Modulus in both parallel and perpendicular direction relative to bedding (Thomsen 1981; Mavko et al. 2009). Describing the anisotropy of shale is the key to the construction of a reservoir shale model (Mavko et al., 2009).

Seismic anisotropy means that elastic properties such as Poisson Ratio and Young's Modulus change due to the direction of measurements. Changes in the elastic parameters have an impact on the brittleness index and hydraulic fracturing for unconventional reservoirs. To solve for those parameters, I have introduced angle parameters based on Rickman's brittleness (Rickman et.al., 2008) which give a new brittleness index estimation and differ from the conventional estimation.

5.2.4.1 Voigt & Reuss-Hill average

The Voigt & Reuss-Hill average (VRH) is the most comprehensive method accepted in literature regardless of crystal symmetry. Therefore, for this present work, I have estimated the Voigt & Reuss Hill bounds for the Pimienta Formation from mineralogy proportions XRD data integration with the support of the 'rppy' a geophysical public library for Python (Contenti, 2019), which contains some functions to determine the bounds in rock physics for these kinds of templates using the X-ray diffraction (XRD) data.

Shale is composed of particles represented by different minerals, each of which has different brittleness values. Quartz and calcite are brittle minerals. In contrast, kerogens and clay have usually been considered as non-brittle materials. If the mineral composition is used the brittleness will have an impact depending on the selection of brittle materials (Alzahabi et al. 2015).

In this project I have used mineral proportions components in two wells (Anhelido-1 and Serbal-1) within Pimienta Formation (reservoir landing zone of horizontal wellbore in its vertical part) to

observe the impact on the brittleness of rock. In consequence, information of elastic properties the information of X-ray diffraction (XRD) was used as shown on Table 5.2.

Anhelido-1	Depth (m)	Quartz	Feldspar	Plagioclase	Calcite	Dolomite	Pyrite	Marcasita	Total Clay
	2104.37	0.489	0.004	0.014	0.318	0.011	0.03	0	0.135
	2113.33	0.057	0	0	0.886	0	0.008	0	0.049
	2115.23	0.45	0.003	0.023	0.228	0.032	0.05	0.02	0.194
	2119.35	0.635	0.004	0.02	0.141	0.003	0.03	0.009	0.159
	Modulus	Quartz	Feldspar	Plagioclase	Calcite	Dolomite	Pyrite	Marcasita	Total Clay
	K Gpa	37	37	75	70	80	145	145	25
	Mu Gpa	45	15	25	30	50	120	120	9
	Rho gr/cc	2.65	2.56	3.07	2.71	2.86	5.02	4.8	2.79
	Depth (m)	Quartz	Feldspar	Plagioclase	Calcite	Dolomite	Pyrite	Marcasita	Total Clay
Serbal-1	2901.9	0.45	0.02	0.04	0.25	0.02	0.03	0.01	0.18
	2903.48	0.3	0.02	0.02	0.49	0.01	0.02	0.01	0.13
	2904.45	0.33	0.02	0.03	0.4	0.01	0.03	0.01	0.16
	2906.12	0.36	0.03	0.05	0.19	0	0.03	0.01	0.32
	2908.77	0.37	0.02	0.06	0.27	0.02	0.05	0	0.21
	2910.85	0.27	0.02	0.04	0.33	0	0.04	0.01	0.28
	2911.35	0.42	0.02	0.04	0.21	0.001	0.04	0.01	0.23
	2912.09	0.41	0.02	0.05	0.2	0	0.05	0.01	0.24
	2913.65	0.33	0.03	0.05	0.21	0	0.05	0.01	0.31
	2914.27	0.33	0.02	0.03	0.29	0	0.03	0.01	0.27
	2916.91	0.03	0.02	0.03	0.75	0	0.02	0	0.14
	2917.4	0.57	0.03	0.04	0.13	0	0.04	0.01	0.18
	Modulus	Quartz	Feldspar	Plagioclase	Calcite	Dolomite	Pyrite	Marcasita	Total Clay
	K Gpa	37	37	75	70	80	145	145	25
	Mu Gpa	45	15	25	30	50	120	120	9
	Rho gr/cc	2.65	2.56	3.07	2.71	2.86	5.02	4.8	2.79

Table 5.2 (A) Elastic properties (e.g., Bulk and Shear moduli) at Anhelido-1 and Serbal-1(reservoir zone) using mineral proportion components X-ray diffraction (XRD).

The Voigt and Reuss -Hill average theory (Mavko et.al., 2009) is used to estimate and predict the elastic modulus of a composition of minerals and pores.

The Voigt and Reuss models of two hypothetical minerals A and B are shown in gray and brown, respectively in Figure 5.29. If the minerals are under the same vertical pressure, the Voigt model produces a parallel connection between the two minerals (A, B) and correspond to the upper bound in a rock physics template. In contrast, the Reuss model produces a serial connection between the two minerals (A, B) and corresponds to the lower bound in a rock physics template.

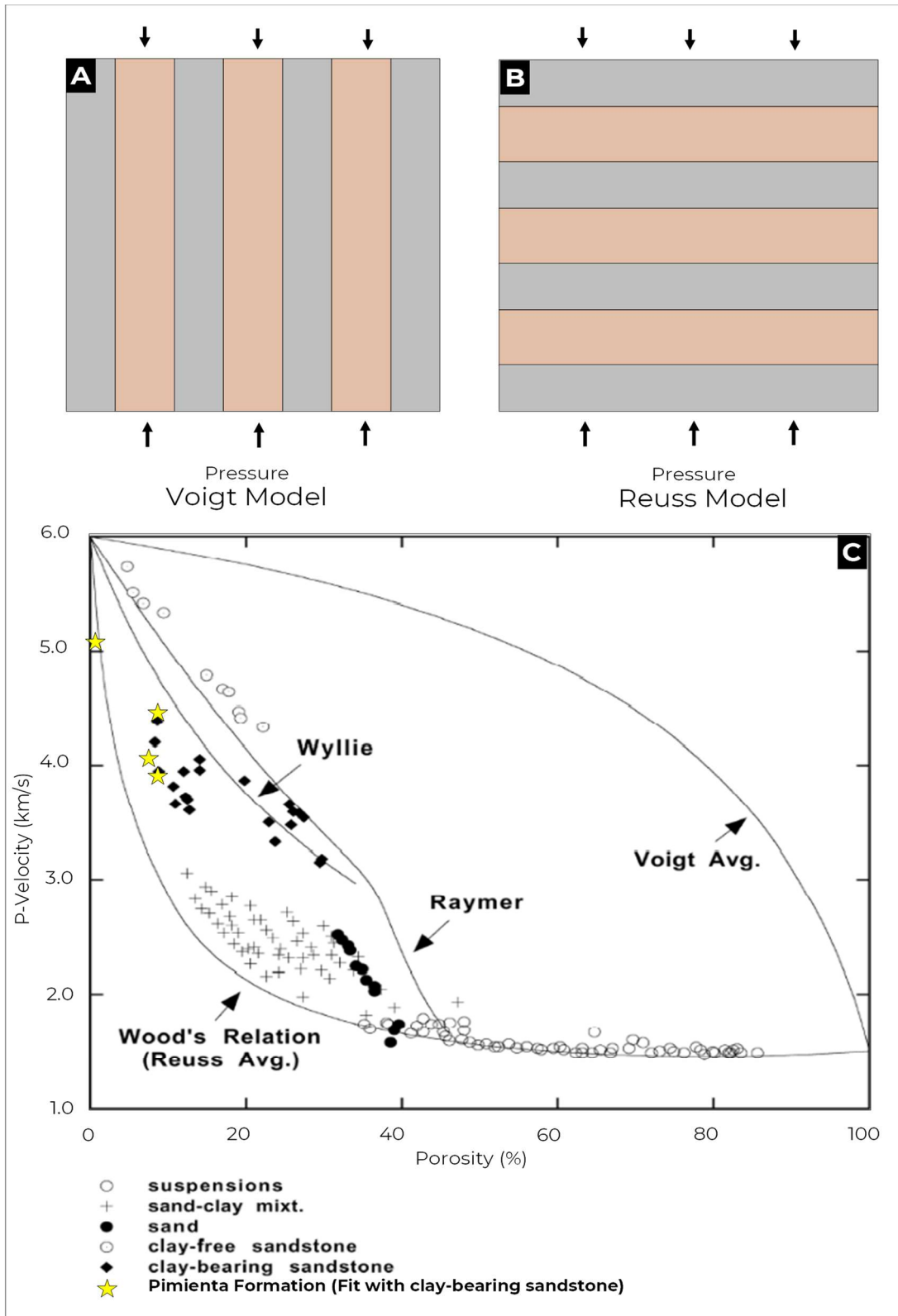


Figure 5.29. (A) Representative of mineral A Voigt model; (B) Representative of mineral B Reuss; (C) Crossplot of empirical lithological models (Porosity (%) vs. P-Velocity (km/s)) (modified from Mavko et.al., 2009 including the Pimienta Formation).

The bound models with the Voigt & Reuss-Hill average (VRH) provides the lower upper bounds and the highest lower bounds, in eq. (5.22). These can be used to estimate the non-organic minerals in terms of volume percent of each mineral. It has been argued that the correct elastic properties of minerals may lie anywhere between the Voigt bound and the Reuss bound (Watt et al. 1976)

The average is expressed as:

$$M_{VRH} = \left(\frac{M_V + M_R}{2} \right) \quad (5.22)$$

Where

$$M_V = \sum_{i=1}^N f_i M_i \quad \frac{1}{M_R} = \sum_{i=1}^N \frac{f_i}{M_i} \quad (5.22a)$$

By using the averages from the (Table 5.1), it is possible to estimate the upper and lower bound limits of the moduli based in the mineralogical composition (Figure 5.30). For this model I have used the well-log data, compressional Vp and porosity at Anhelido-1 and Serbal-1, respectively within the target zone to plot a scatter graph.

In terms of constituents the bulk modulus K and Shear Modulus μ by Voigt (Upper) and Reuss(lower) bounds are used to obtain the effective elastic moduli of the rock.

For Example, at depth of 2115 in Anhelido-1, we have:

Non-Kerogen

$K_{voigt} = 52.67 \text{ GPa}$

$K_{reuss} = 36.15 \text{ GPa}$

For Kerogen = 0.05 fraction we have use bulk modulus of 4 GPa value according on Yan et.al, (2013) based on ultrasonic velocities on 9 laboratory isolated kerogen samples in shale rock.

$K_{\text{voigt}} = 50.70 \text{ GPa}$

$K_{\text{reuss}} = 33.80 \text{ GPa}$

At depth of 2908m in Serbal-1 we have:

Non-Kerogen

$K_{\text{voigt}} = 47.92 \text{ GPa}$

$K_{\text{reuss}} = 34.02 \text{ GPa}$

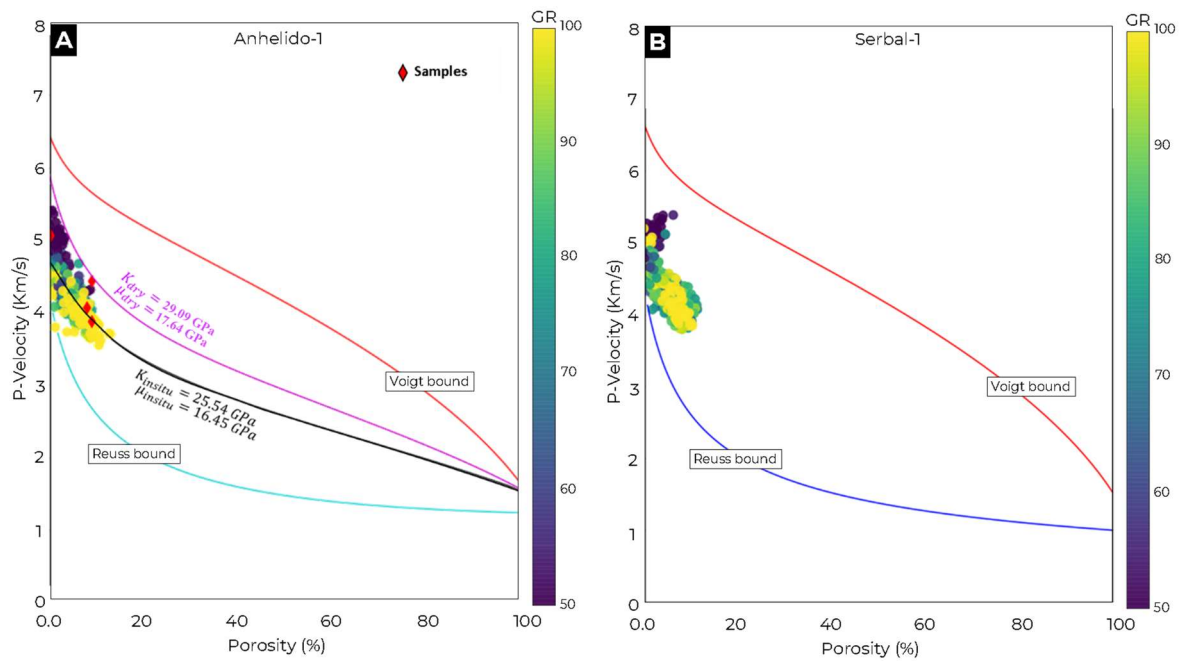


Figure 5.30. Crossplot Porosity vs P-Velocity with Gamma Ray color-coded; (A) Voigt and Reuss bounds at Anhelido-1 within the Pimienta Formation (reservoir zone); (B) Voigt and Reuss bounds at Anhelido-1 within the Pimienta Formation (reservoir zone), in A) Anhelido-1 Porosity vs. V_p log data and samples and B) Serbal-1 using Python code.

The scattering plot Density vs. P-velocity of the Pimienta Formation is close to the Reuss bound as shown in Figure 5.31 and Figure 5.32 and fits very well with the Friable-Sand Model using RokDoc software. This is thought to be due to the quartz proportion at Anhelido-1 and Serbal-1 respectively within the Pimienta Formation.

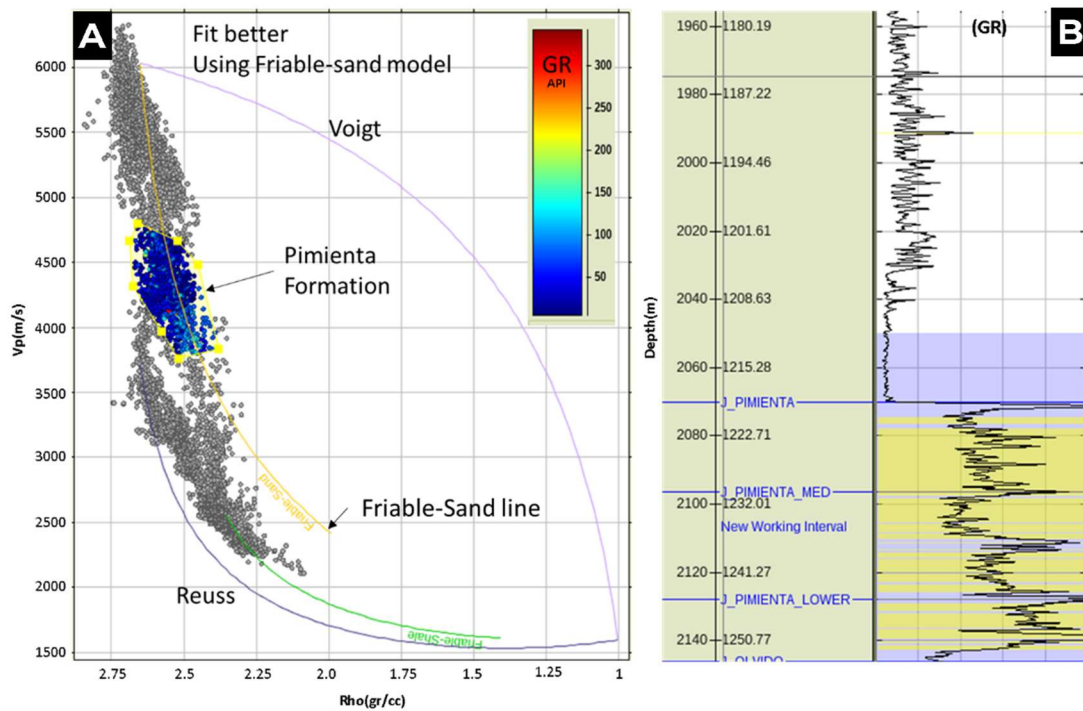


Figure 5.31 (A) Scattering plot of Density vs. P-Velocity within the Pimienta Formation according to XRD and well logs data using RokDoc software; (B) The yellow polygon in crossplot highlight the Gamma Ray log in the Pimienta formation at Anhelido-1 within the Pimienta Formation.

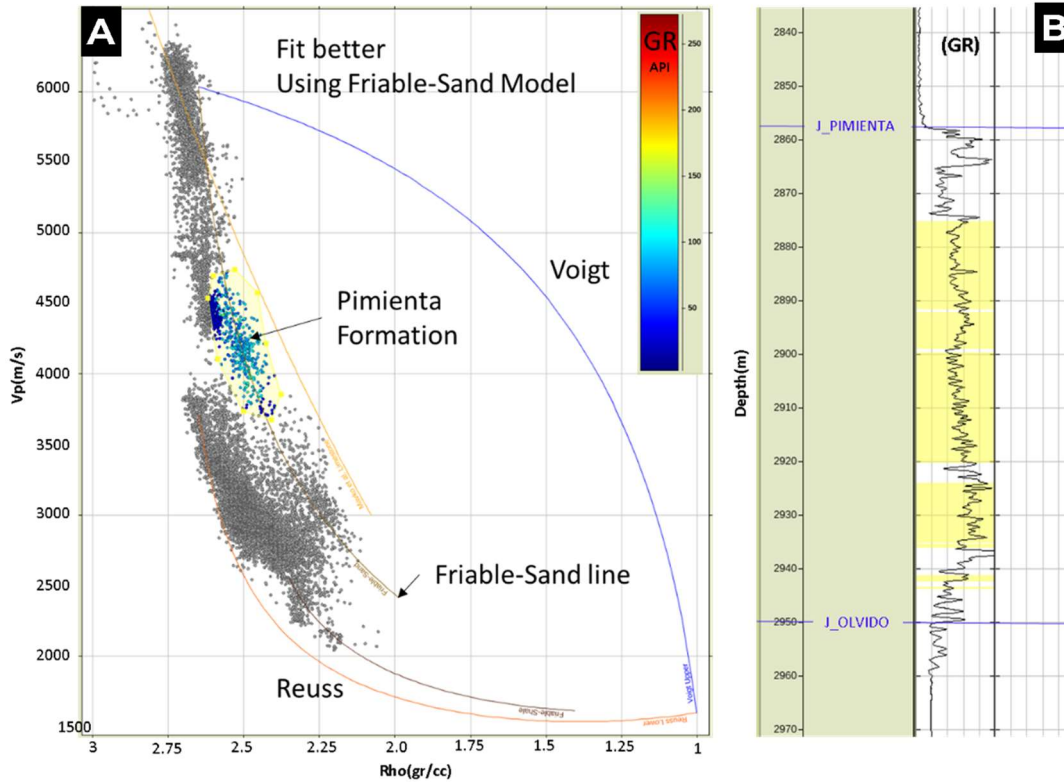


Figure 5.32 (A) Scattering plot of Density vs. P-Velocity within the Pimienta Formation according to XRD and well logs data using RokDoc software; (B) The yellow polygon in crossplot highlight the Gamma Ray log at Serbal-1 within the Pimienta formation.

The clay particles themselves are anisotropic in their alignment, and the bedding-parallel lamination of the kerogen further enhances this anisotropy (Sayers, 2011). Kerogen and TOC also have an impact on the Thomsen anisotropy parameters ϵ , γ , and δ . However, various studies have concluded conflicting observations about these coefficients.

A study by Vernik and Landis (1996) concluded that epsilon increases with increasing kerogen/TOC up to a critical point (kerogen volume of about 35 to 40%). However, Sayers (2014) concludes that ϵ and γ are not as sensitive to kerogen, and that δ is very sensitive to the amount of kerogen as can be seen in (Table 5.2) where epsilon is affected from non-kerogen to kerogen filled.

I have estimated the Thomsen's parameters with non-kerogen, and kerogen fraction of 0.05 based on the Reuss bound and as Vernik and Landis (1996) concluded the it slightly change from non-kerogen to kerogen filled as it can be seen in Table 5.3. In terms of elastic properties, cross-plotting using P-

Impedance and S-impedance (PI-SI) in the scatter plot with other shale rocks reservoir of USA, the Pimienta Formation is seen to exhibit higher impedance values (Figure 5.33).

Non-Kerogen	Kvoigt (GPa)	Kreuss (GPa)
0	50.7	33.8
Kerogen		
0.05	47.92	31.02

Table 5.3. Voigt and Reuss bounds for Anhelido-1 showing differences between kerogen filled and non-kerogen filled fracture cases.

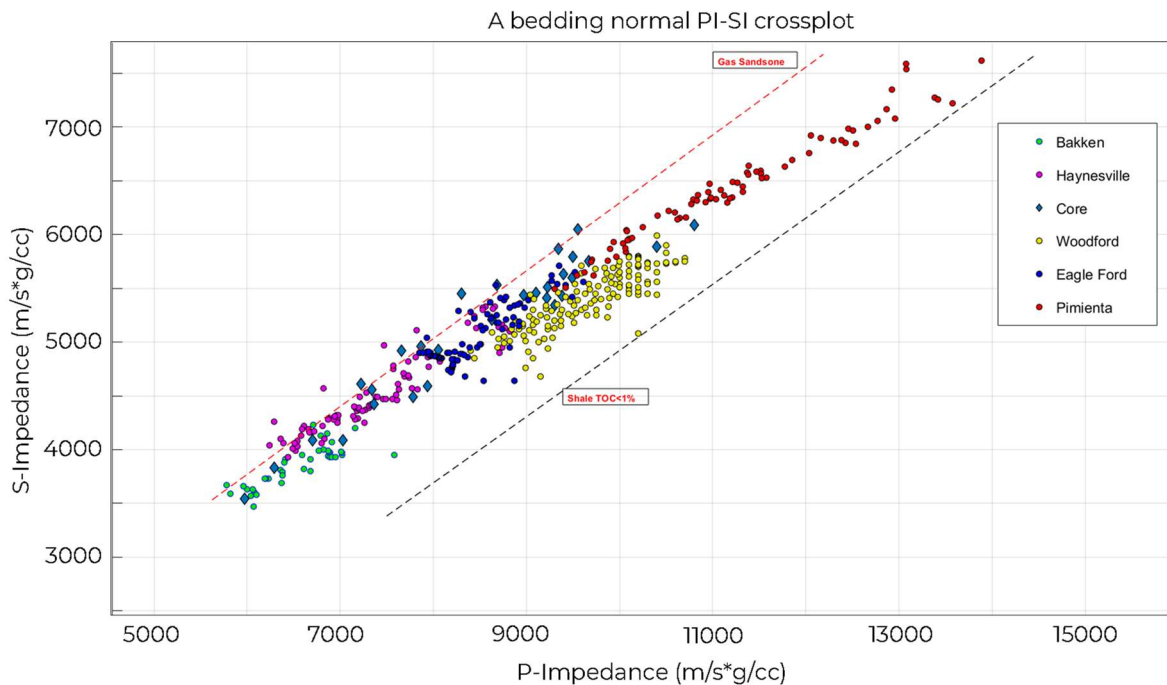


Figure 5.33 A normal bedding P-Impedance vs S-Impedance scattering with log data of different shale formation of the USA, including the Pimienta Formation (red). Adapted from Khadeeva and Vernik (2014). The Pimienta Formation is stiffer than its counterparts due to high P/S-impedance.

5.2.4.2 Anisotropic Young's Modulus and Poisson's Ratio

In most cases, the static modules are different from the dynamic modules for the same rock sample because the relationship between stress and deformation in rocks is usually not linear. As a result, the stress-strain relationship under large deformations will be different from the deformation stress ratio under minimal deformation. Furthermore, rocks tend to have annealed behaviour because of

sliding friction through microcracks and rearrangement of particles (David et.al., 2012). Another reason is due to the dependence of the frequency (dispersion), which contributes significantly to the static-dynamic discrepancy on the shales (Holt et al., 2012).

The relationships between dynamic and static modules are not universal and straightforward, mainly because the velocity of the elastic wave in a sample and the resulting dynamic elastic modules depend on the conditions of the measurement, specifically the effective pressure and fluids within the pore system. Also, the static moduli depend on the specifications of the load test. Even for the same type of test, for example, axial load, the static Young's Modulus can be strongly affected by the stress applied to the sample, as well as by the magnitude of the axial deformation that is why there are significant variations between static and dynamic modules (Mavko, 2009).

Vernik et. al., (1992) from laboratory measurements proposed to measure P-wave, S-wave velocities, parallel, orthogonal, and at 45° to the symmetry axis in the three-plug principle (Figure 5.34).

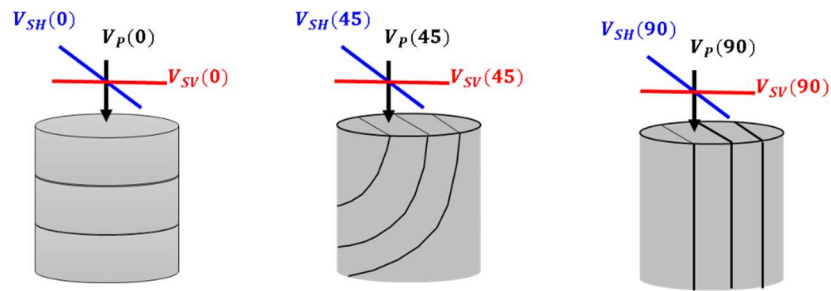


Figure 5.34. Illustration of P-wave, Swave propagation, and polarization fractions concerning the bedding plane of organic shale. The value in parenthesis indicates the angle for the bedding normal symmetry axis (modified from Vernik and Nur, 1992).

Using the principle previously described can be obtained the elastic constants, Vernik et. al., (1992) to measure V_p and V_s orthogonal, parallel and 45 degrees to the symmetry axis gives the next elastic constants.

$$C_{11} = \rho V_p^2(90^\circ) \quad (5.23)$$

$$C_{12} = C_{11} - 2\rho V_{SH}^2(90^\circ) \quad (5.24)$$

$$C_{13} = -C_{44} + \sqrt{4\rho^2 V_p^4(45^\circ) - 2\rho V_p^2(45^\circ)(C_{11} + C_{33} + 2C_{44} + (C_{11} + C_{44})(C_{33} + C_{44}))} \quad (5.25)$$

$$C_{33} = \rho V_p^2(0^\circ) \quad (5.26)$$

$$C_{44} = \rho V_{SH}^2(0^\circ) \quad (5.27)$$

$$C_{66} = \rho V_{SH}^2(90^\circ) \quad (5.28)$$

The anisotropic brittleness with linear-slip criteria is as follows:

$$S_{ij} = \begin{bmatrix} S_{11} & S_{12} & S_{13} & 0 & 0 & 0 \\ S_{12} & S_{11} & S_{13} & 0 & 0 & 0 \\ S_{13} & S_{13} & S_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & S_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & S_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & S_{66} \end{bmatrix} \quad (5.29)$$

S_{ij} is related to C_{ij} by follow value expressions:

$$S_{11} + S_{12} = C_{33}/C \quad (5.30a)$$

$$S_{11} - S_{12} = \frac{1}{C_{11} - C_{12}} \quad (5.30b)$$

$$S_{13} = \frac{-C_{13}}{C} \quad (5.30c)$$

$$S_{33} = \frac{(C_{11} + C_{12})}{C} \quad (5.30d)$$

$$S_{44} = \frac{1}{C_{66}} \quad (5.30e)$$

Where

$$C = C_{33}(C_{11} + C_{12}) - 2C_{13}^2 \quad (5.30f)$$

In terms of Poisson ratio and Young's Modulus, the inverse of S_{ij} expression of compliance tensor is as follows:

$$S_{ij} = C^{-1} = \begin{bmatrix} \frac{1}{E_{11}} & \frac{-v_{12}}{E_{11}} & \frac{-v_{13}}{E_{33}} & 0 & 0 & 0 \\ \frac{-v_{12}}{E_{11}} & \frac{1}{E_{11}} & \frac{-v_{13}}{E_{33}} & 0 & 0 & 0 \\ \frac{-v_{13}}{E_{33}} & \frac{-v_{13}}{E_{33}} & \frac{1}{E_{33}} & 0 & 0 & 0 \\ 0 & 0 & 0 & \frac{1}{\mu_{13}} & 0 & 0 \\ 0 & 0 & 0 & 0 & \frac{1}{\mu_{13}} & 0 \\ 0 & 0 & 0 & 0 & 0 & \frac{2 - 2v_{12}}{\mu_{12}} \end{bmatrix} \quad (5.31)$$

Then to estimate the Poisson ratio and Young's Modulus applied to log data using the angles based in Luan et al. (2014) in terms of Thomsen's parameters, I computed the horizontal and vertical Young's Modulus and Poisson Ratio:

Vertical Poisson Ratio:

When $\theta = 0^\circ$

$$v(\theta) = v_{well} \left(1 + \left(\frac{\delta}{1 - 2g} \right) - \left(\frac{(\varepsilon - \gamma g^2)}{1 - g^2} \right) \right) \quad (5.32)$$

Horizontal Poisson ratio:

When $\theta = 90^\circ$

$$v(\theta) = v_{well} \left(1 + \left(\frac{\varepsilon}{2g^2(1-2g^2)(1-g^2)} \right) - \left(\frac{2\gamma}{1-2g^2} \right) - \left(\frac{\delta}{1-g^2} \right) \right) \quad (5.33)$$

Where v_{well} is the Poisson ratio calculated from the well-log data using normal P-wave, S-wave and g is the isotropic background velocity.

Vertical Young's Modulus

When $\theta = 0^\circ$

$$E(\theta) = (E_{dyn} - (4v_{well}\delta) + 4v_{well}^2(\varepsilon - g\gamma)) \quad (5.34)$$

Horizontal Young's Modulus

When $\theta = 90^\circ$

$$E(\theta) = E_{dyn} \left(1 + \frac{-\varepsilon(1-2g)\delta}{2g(3-4g)(1-g)} + \frac{4(1-2g)\gamma}{(3-4g)} \right) \quad (5.35)$$

Where $E(\theta)$ is the Young's Modulus in different directions; $v(0^\circ, 90^\circ)$ is Poisson's Ratio respectively $v(\theta)$.

To estimate brittleness is needed to compute the normalized Young's Modulus $E_{N(0^\circ)}$ & $E_{N(90^\circ)}$ and the Poisson's Ratio $v_{N(0^\circ)}$ & $v_{N(90^\circ)}$ for every direction as follows:

$$E_{N(0^\circ)} = \frac{E(0^\circ) - E(0^\circ)_{min}}{E(0^\circ)_{max} - E(0^\circ)_{min}} \quad (5.36)$$

$$E_{N(90^\circ)} = \frac{E(90^\circ) - E(90^\circ)_{min}}{E(90^\circ)_{max} - E(90^\circ)_{min}} \quad (5.37)$$

$$v_{N(0^\circ)} = \frac{v(0^\circ) - v(0^\circ)_{min}}{v(0^\circ)_{max} - v(0^\circ)_{min}} \quad (5.38)$$

$$v_{N(90^\circ)} = \frac{v(90^\circ) - v(90^\circ)_{min}}{v(90^\circ)_{max} - v(90^\circ)_{min}} \quad (5.20)$$

Where $E_{N(0^\circ)}$ & $v_{N(0^\circ)}$ the vertical Young's Modulus and Poisson's Ratio, and $E_{N(90^\circ)}$ & $v_{N(90^\circ)}$ the horizontal Young's Modulus, and Poisson's Ratio.

$E(\theta)_{max}, E(\theta)_{min}, v(\theta)_{max}, v(\theta)_{min}$ are the maximum and minimum value of Young's Modulus and the Poisson's Ratio in every direction.

5.2.4.3 Anisotropic Brittleness

Finally, by adding an extra dimension into the Rickman et.al., (2008) equation, the anisotropic brittleness is computed using the equation below in two main directions, vertical and horizontal.

$$Brit_V = \frac{E_{N(0^\circ)} + v_{N(0^\circ)}}{2} \quad (5.39)$$

$$Brit_H = \frac{E_{N(90^\circ)} + v_{N(90^\circ)}}{2} \quad (5.40)$$

Where $Brit_V$ is vertical brittleness and $Brit_H$ horizontal brittleness. With these equations, the anisotropic brittleness logs were estimated at 0° and 90° at Anhleido-1 and Serbal-1 respectively as shown in Figure 5.35 and Figure 5.36.

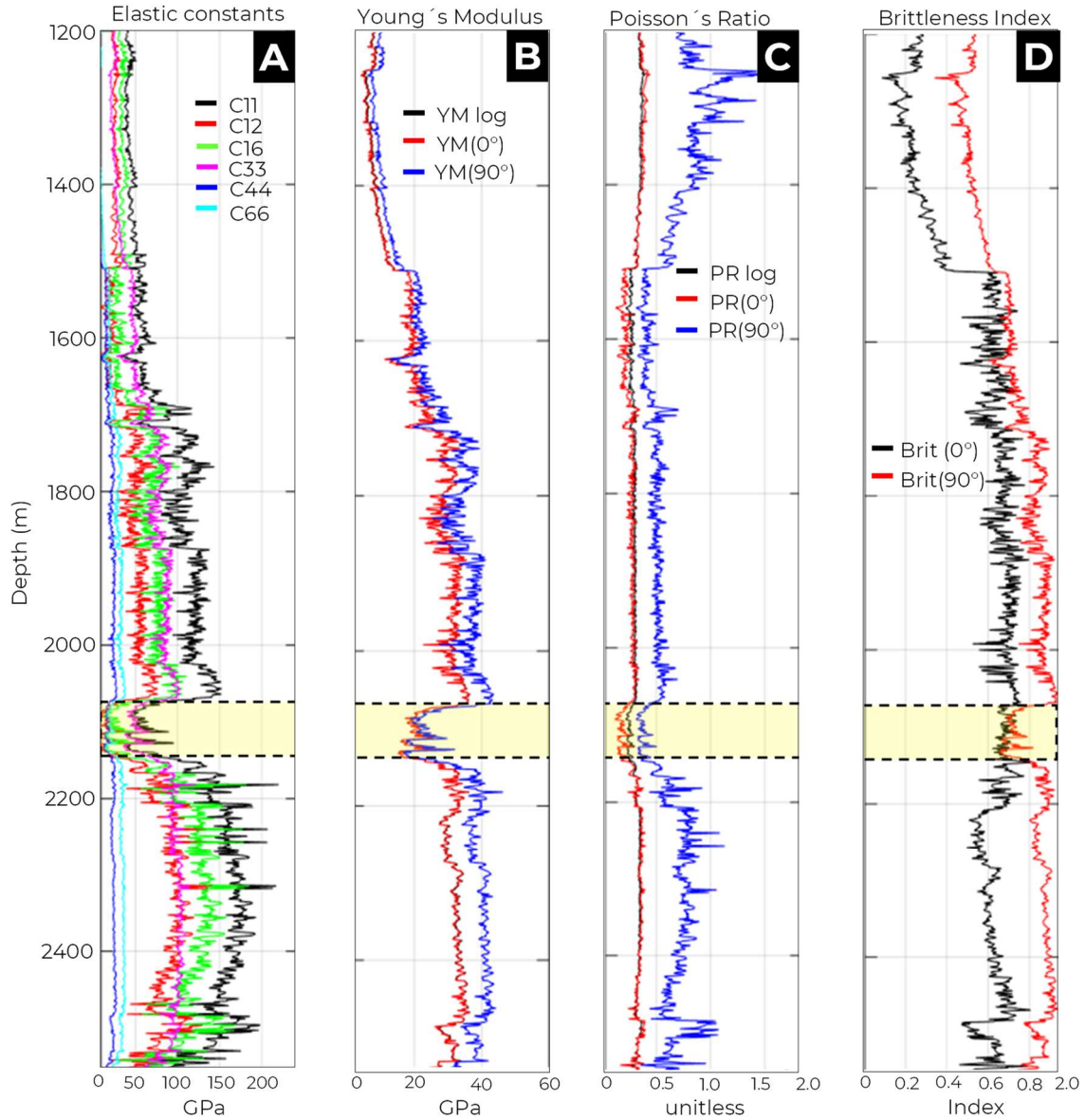


Figure 5.35 (A) Elastic constants; (B) Young's Modulus (well-log), Vertical (0°) & Horizontal (90°) Young's Modulus; (C) Poisson's Ratio (well-log), Vertical (0°) & Horizontal (90°) Poisson's Ratio; (D) Vertical (0°) or BI (0°) & Horizontal (90°) or BI (90°) Brittleness index at Anhelido-1. The Pimienta Formation is highlighted in yellow.

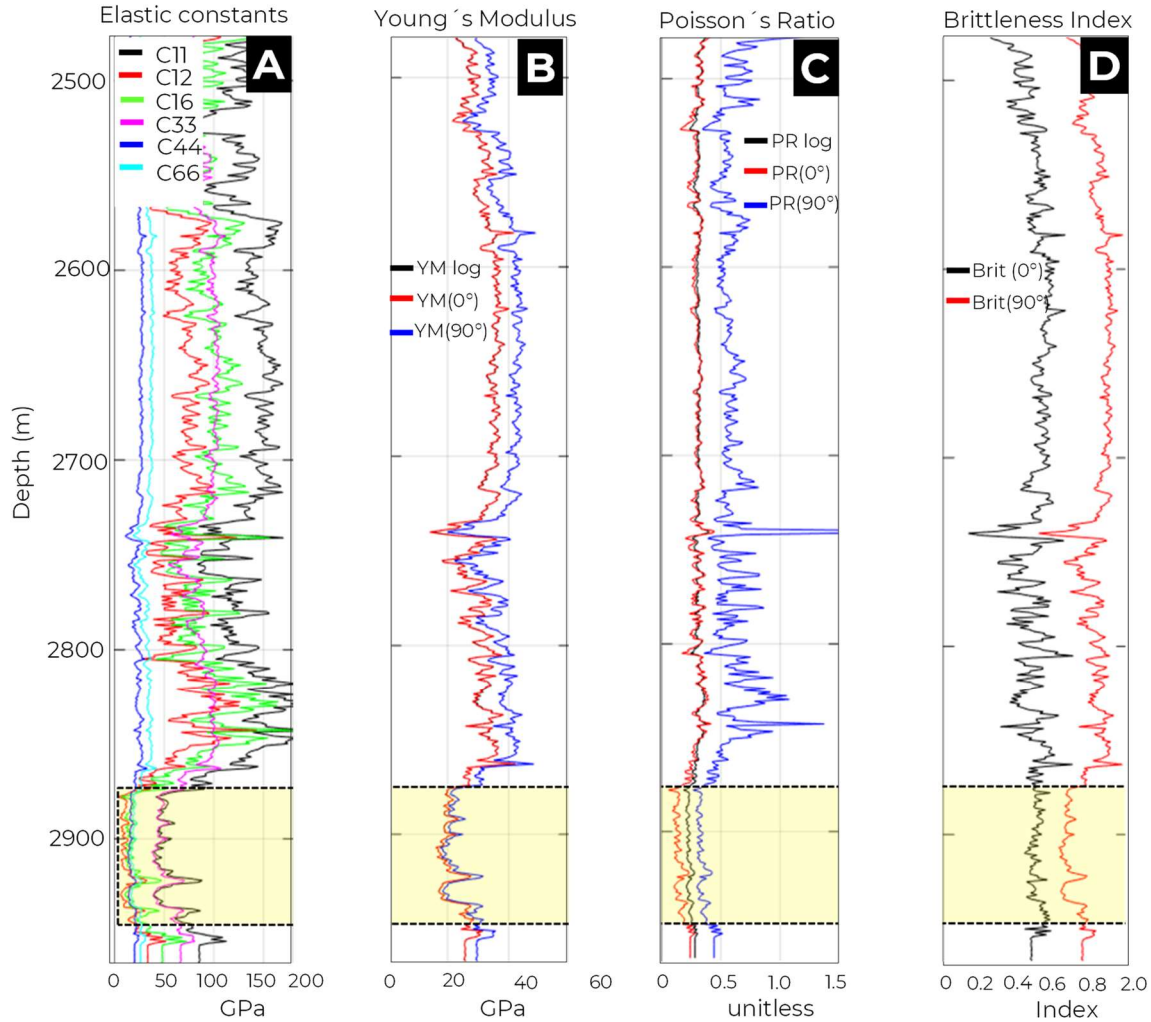


Figure 5.36 (A) Elastic constants; (B) Young's Modulus (well-log), Vertical (0°) & Horizontal (90°) Young's Modulus; (C) Poisson's Ratio (well-log), Vertical (0°) & Horizontal (90°) Poisson's Ratio; (D) Vertical (0°) or BI (0°) & Horizontal (90°) or BI (90°) Brittleness index at Serbal-1, the Pimienta Formation is highlighted in yellow.

Anisotropic Brittleness predictions differed between the vertical and horizontal equations, which indicate that rock mechanical behaviour is not only related to the mineralogy but also to the elastic and physical characteristics of the rock. Figure 5.37 shows the different brittleness index predictions by previous researchers and those calculated in this research study (e.g., BI (0°) and BI (90°)) applied at Anhelido-1 and Serbal-1.

Guo et.al., (2012) found that the Brittleness defined by Young's modulus is not consistent with the definition in terms of $(\lambda + 2\mu)/\lambda$ and Poisson's ratio, Young's modulus is a good indicator for the variation of crack density whereas the pore-type inversion showed that the variation of pore types coincides with inverted crack density in their work. This research comprises the analysis of brittleness fractures, and microstructure of the Barnett Shale for a better understanding of the correlation between mechanical properties, mineralogy, and pore geometry using the self-consistent approximation (SCA) model.

Sharma et.al., (2012) proposed a new attribute ($E\rho$) in the form of a product of Young's modulus and density, which is a good lithology indicator. In their work they described it as a scaled version of the ($\mu\rho$) attribute and illustrate that it intensifies the variation in lithology. This attribute can be derived seismically and have shown that it can be determined the brittleness of a formation with it. Chen et.al., (2014) proposed a rock physics effective model, from four aspects of quartz content, organic matter, porosity and fluid types, the new brittle indicating factor was compared with the routine index of rock brittleness –Young's modulus. Tests on real datasets showed that the new brittle indicating factor is more sensitive than Young's modulus when used in predicting the gas-bearing brittle shale reservoir. Goodway et.al., (2010) introduced Lamé coefficient, and shear modulus as new parameters to characterize brittleness (Figure 5.37).

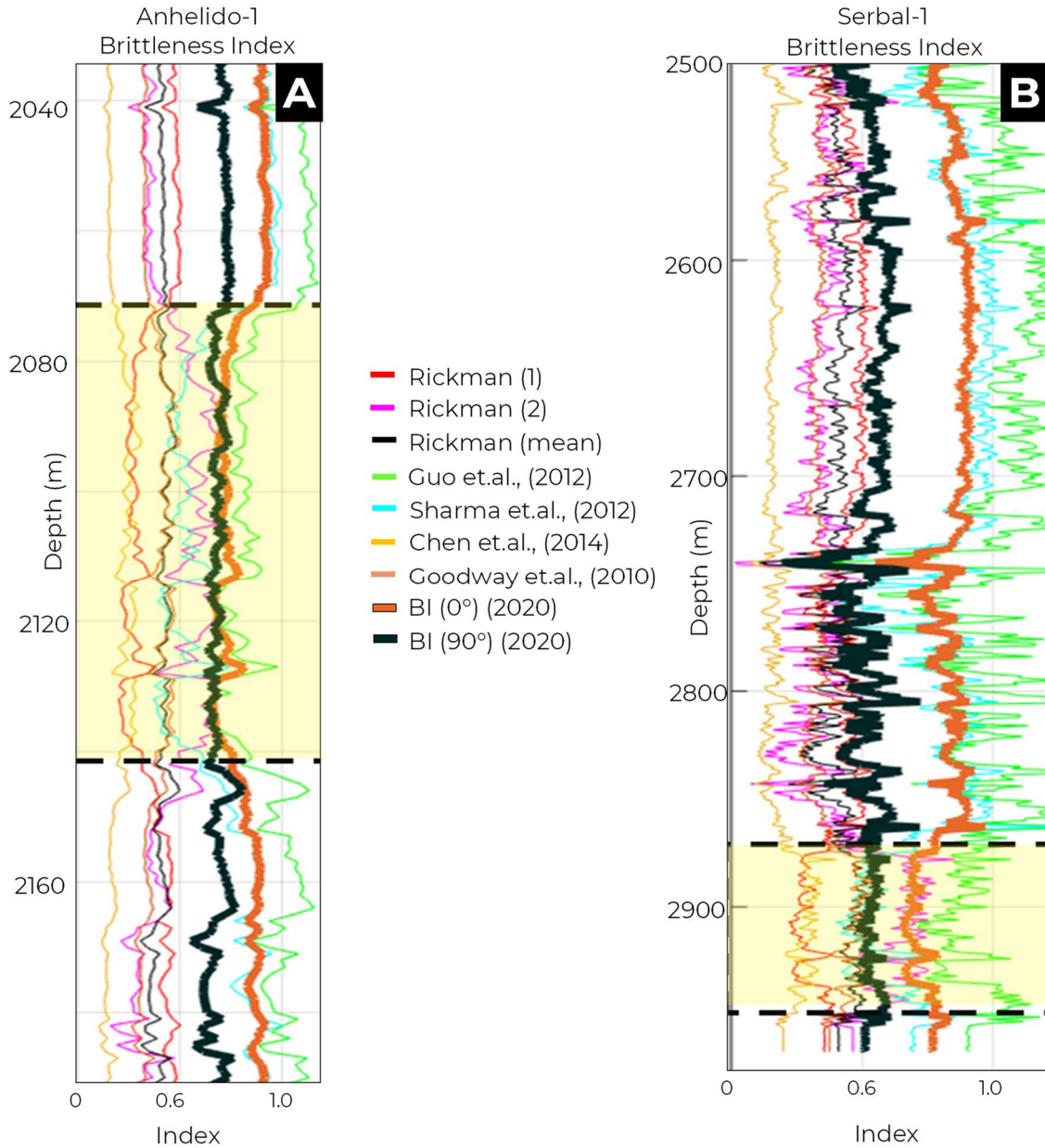


Figure 5.37. (A) Different Brittleness index estimation by different research approaches, including the anisotropic Brittleness proposed in this thesis work (BI (0°) black and BI (90°) Orange) at Anhelido-1; (B) Different Brittleness index estimation by different research approaches, including the anisotropic Brittleness proposed in this thesis work (BI (0°) black and BI (90°) Orange) at Serbal-1; Pimienta Formation is highlighted in yellow.

Using well log data, the anisotropic modulus and brittleness are compared in a scatter plot. The changes in Poisson's Ratio and Young's modulus may reveal anisotropy parallel and perpendicular to the bedding describing this anisotropy in shale rock which is the key to the construction of rock physics templates.

Based on those changes, I have estimated the rock physical characteristics using the induced anisotropy to compute the anisotropic brittleness only for 0° and 90° degrees through a graphical user interface in MATLAB that I created for this application in this study which I termed “BrittleAzMod” (Appendix B2) (Figure 5.39). In (Figure 5.38), is shown the rock physics template with the background colour-coded with vertical and horizontal brittleness.

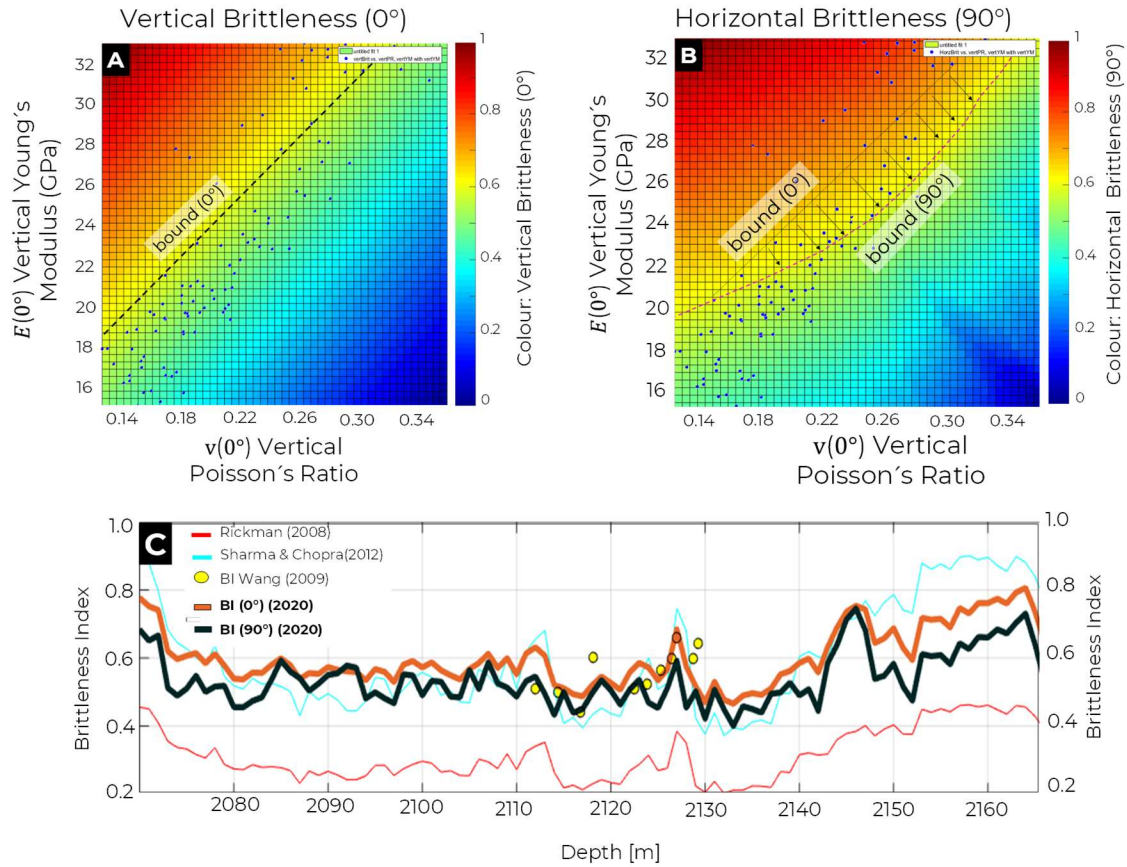


Figure 5.38 (A) Anisotropic rock physics scatter plot of vertical Young's Modulus-Poisson's Ratio, color-coded with vertical (0°) brittleness; (B) Anisotropic rock physics scatter plot of vertical Young's Modulus-Poisson's Ratio, color-coded with horizontal (90°) brittleness; (C) Vertical BI (0°) and horizontal BI (90°) brittleness logs proposed in this work fit much better with the brittleness from mineral proportions XRD (Wang, 2009) in comparison with another researcher's brittleness. The bound in the scatter plot changes dramatically when it goes from 0° to 90° , which may reveal anisotropy induced by mechanical properties in the rock itself.

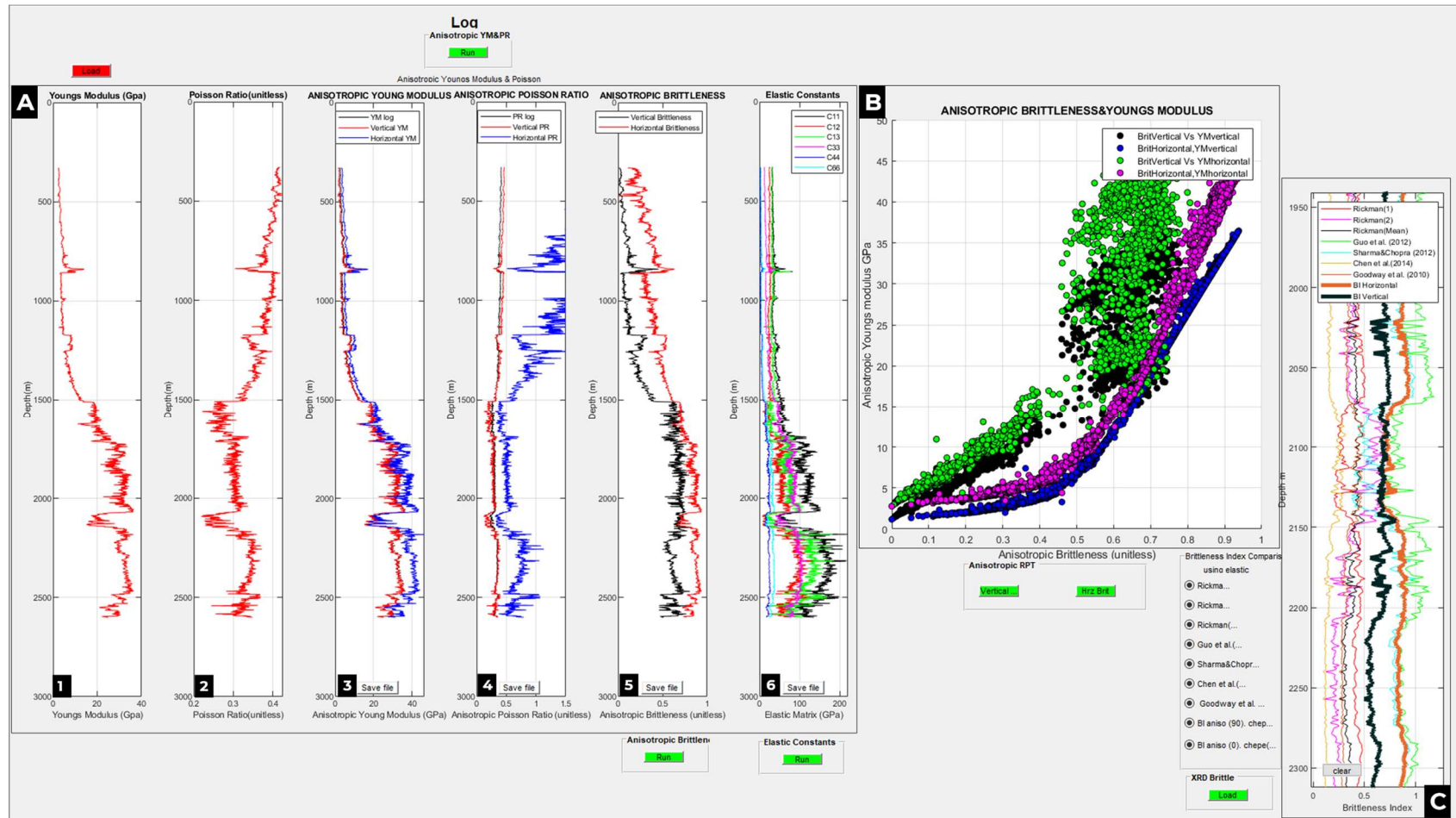


Figure 5.39 Graphical User Interface developed in MATLAB; (A) From left to right the displayed logs are (1) Young's Modulus, (2) Poisson's Ratio, (3) Anisotropic Young's Modulus, (4) Anisotropic Poisson's Ratio, (5) Anisotropic Brittleness, (6) Elastic constants; (B) Scatter plot (Anisotropic Brittleness vs Anisotropic Young's Modulus); (C) Anisotropic Brittleness Index of different researchers including BI (0°) and BI (90°) proposed in this thesis.

5.2.5 Effective field method (EFM) within Pimienta Formation

For over two centuries, engineers, physicists, and mathematics have studied heterogeneous random media in detail. Examples of random microstructures include composites and nanomaterials, geological features, metals, and polymers at a particular scale. Such scientists as Poisson, Mossotti, Clausius, Lorenz, Lorentz, Maxwell, and others have focused on the challenge of estimating their effective physical qualities (the homogenization problem) (Kanaun and Levin, 2013).

They provided the first approximations in their ground-breaking publications, which implicitly employed variants of the self-consistent effective field approach. But the method's precise formulations didn't emerge until the first part of the 20th century.

The estimation of elastic wave propagation velocities in cracked rocks is addressed by the effective field method, which is a component of the self-consistent scheme. The data from DSI cross-dipole measurements from well-log were used to model the crack density for sub-vertical fractures and their orientation angles.

Effective medium approaches are a different class of self-consistent schemes (EMM). These techniques treat each inclusion as an isolated entity within the medium with the composite's functional characteristics. As a result, the interactions between inclusions are considered in different ways in the EFM and EMM. The predictions made by the approaches differ as a result. In Kanaun and Levin (2008), the EFM and EMM are compared. One advantage of the EFM over the EMM is that the EFM produces explicit equations for the effective characteristics for composites with ellipsoidal inclusions, whereas the EMM results in implicit equations that are frequently only amenable to numerical solutions.

In this work I aim to characterize how inclusions' unusual spatial distributions affect their effective qualities using the effective field method, which is not achievable using any other approach.

Natural rocks with voids, cracks, and inclusions can be viewed as an elastic homogenous medium with a random field of different types of inhomogeneities. Such materials have random functions for physical fields. When applied to rock materials, the main challenge of micromechanics is to assess the statistical moments of these fields due to various forms of external forcing. The homogenization challenge is the finding of the mean values of various fields (such as the stress and strain fields) and the correlations between these mean values. After this issue is resolved and these relationships are built, it will be possible to swap out an inhomogeneous rock material with a homogeneous one that has the same effective (overall) qualities as the original medium. The interactions between both the original media and this homogeneous medium at the macroscopic level

The homogenization problem becomes that of an isolated inclusion contained within a homogeneous matrix when the inhomogeneities volume concentration (or density) is low (no interaction). This issue can be precisely resolved for elliptic fractures and homogeneous ellipsoidal inclusions, allowing for the construction of the precise homogenization problem solution in these circumstances (Nur, 1971; Anderson et al., 1974; Hudson, 1981, 1990; Peacock & Hudson, 1990; Sayers & Kachanov, 1991; Kachanov, 1992, 1993; Cheng, 1993; Thomsen, 1995; Xu, 1998; Schubnel & Gueguen, 2003)

The homogenization problem becomes more challenging since it requires solving the so-called many-particle problem at high crack densities when interactions between inclusions are crucial.

There is only an approximation to the exact solution of the many-particle issue for a medium with a random set of inhomogeneities. We are able to provide approximations of solutions to numerous particle problems of various types using a class of techniques known as self-consistent approaches. These techniques reduce a many-particle problem to a problem for a single particle by employing physically plausible theories. If the latter can be resolved, the homogenization problem's solution can likewise be built. Self-consistent schemes, which are frequently employed in geomechanics

(O'Connell & Budiansky, 1974; Budiansky & O'Connell, 1976; Korringa & Thompson, 1977; Berryman, 1980, 1992), are variations of the so-called effective medium method (EMM).

The many programs created by Henyey and Pomphrey (1982), Norris (1985), Sheng (1991), and Hornby et al (1994), LaRevalet and Gueguen (1996), Jacobsen et al. (2000), and Saenger and Shapiro (2002) is also essentially a version of EMM (this version is also called the differential effective medium method (DEM) addressed in this chapter section 5.2.3).

Another self-consistent approach in theoretical physics is distinct from EMM (or DEM). Each inclusion in an inhomogeneous media is viewed as an isolated inclusion in the homogeneous background medium according to this method (matrix). The external field acting on the medium is not the same as the field acting on this inclusion (effective field). The perturbations brought on by all nearby inclusions are added to this external field. A self-consistent strategy like this is referred to as an effective field approach (EFM). The effective field is taken to be constant and the same for all inclusions in the most basic version of the EFM (quasi-crystalline approximation).

This approach has a lengthy history and has mostly been applied to the theory of phase transitions and nuclear physics to describe various kinds of interactions involving several particles. This technique has been applied by Kanaun [1982, 1983], Kanaun and Levin (1993, 1994), and Markov (2001) to the mechanics of composite materials. Unfortunately, this approach is rarely used when dealing with geomechanics-related issues.

Over the EMM, the EFM has some advantages. Instead of the system of nonlinear algebraic or differential equations for these parameters that were produced under multiple iterations of the EMM, the EFM frequently offers unambiguous expressions for the effective parameters of inhomogeneous materials. The later equations are typically only amenable to numerical solutions.

In all inclusion density ranges, the formulas for the effective parameters of inhomogeneous materials produced with the EFM are physically accurate. The EFM offers several advantages over the EMM for inclusion and matrix qualities that are arbitrary constant.

In many circumstances, the effective parameters of inhomogeneous materials are expressed explicitly by the EFM rather than through a set of nonlinear algebraic or differential equations, as they would be by different EMM iterations. In most cases, the latter equations can only be quantitatively solved. The formulas for the effective parameters of inhomogeneous materials generated with the EFM are physically accurate over the entire ranges of inclusion density and for any arbitrary constant features of the inclusions and the matrix.

When the component attributes are highly contrasted, the EFM's predictions are more in line with the experimental data than the EMM's. The EFM provides for the description of the effect of the peculiarities of the spatial distribution of the inclusions on the effective qualities, which is not achievable in any version of the EMM (Kanaun & Levin, 1994). With comprehensive statistical data regarding the microstructure of the composite material, it is possible to incrementally enhance the predictions of the EFM (Kanaun, 2003).

The EFM will be used in this study to determine the effective elastic moduli of rock materials having dry and fluid-filled fractures found in the Pimienta Formation. The method used in this study is different from the DEM method discussed in section XX. Every crack-like inclusion in the rock material is thought to have a unique local external field operating on it. The orientation of the inclusion under examination must be considered, though. A better description of the interactions between fissures in rock materials is now possible because to this modification of the EFM, which Kanaun (1993) first suggested.

The EFM reduces the many-particle issue's solution to that of a single-particle problem. In the latter, an isolated inclusion in an infinitely homogenous media loaded by a constant external field faces an elastic issue. Physically, the ratio of the characteristic elastic moduli of the confinement and the medium, and geometrically, the ratio of the characteristic diameters of the confinement, are the two minor parameters in this problem for crack-like confinement. For applications, only the asymptotes of the solution for these parameters are necessary.

Penny-shaped cracks

Let us consider penny shaped cracks with orientation m coaxial to the inclusion for this case, tensor

$Q_{ijkl}(m)$ in the T basis is defined by

$$Q_{ijkl}(m) = q_1 T_{ijkl}^2 + q_2 \left[T_{ijkl}^1(m) - \frac{1}{2} T_{ijkl}^2(m) + q_3 (T_{ijkl}^3 + T_{ijkl}^4) + \right. \\ \left. q_5 T_{ijkl}^5(m) + q_6 T_{ijkl}^6(m) \right], \quad (4.34)$$

$$q_1 = -\mu_0 [4\kappa_0 - 1 - 2(3\kappa_0 - 1)f_0 - 2f_1],$$

$$q_2 = -2\mu_0 [1(-2 - \kappa_0)f_0 - f_1],$$

$$q_3 = -2\mu_0 [(2\kappa_0 - 1)f_0 + 2f_1],$$

$$q_5 = -4\mu_0 (f_0 + 4f_1),$$

$$q_6 = -8\mu_0 (\kappa_0 f_0 - f_1),$$

Where

$$f_0 = \frac{1 - g}{2(1 - \Upsilon^2)}, f_1 = \frac{\kappa_0}{4(1 - \Upsilon^2)^2} [(2 - \Upsilon^2)g - 3\Upsilon^2], \quad (4.34)$$

$$g = \frac{\Upsilon^2}{\sqrt{\Upsilon^2 - 1}} \arctan \sqrt{\Upsilon^2 - 1}, \Upsilon = \frac{\alpha}{\alpha_3} > 1$$

And κ_0 is determined in equation (Appendix B.4)

Considering the case when all the cracks have the same orientation m . In this case, the average over orientations in the right-hand side of equation (54) for S^* is absent, and the tensor of elastic compliances can be written in the form.

$$S_{ijkl}^* = S_{ijkl}^0 + \frac{4\bar{M}_1}{4 + \bar{M}_{1q5}} T_{ijkl}^5(m) + \frac{\bar{M}_2}{4 + \bar{M}_{2q6}} T_{ijkl}^6(m), \quad (4.34)$$

Where

$$\begin{aligned} \bar{M}_1 &= \left\langle \frac{\tau}{2\mu_0} \left[\frac{a\mu}{2h\mu_0} + \frac{(2 - v_0)}{(1 - v_0)} \right]^2 \right\rangle \\ \bar{M}_2 &= \left\langle \frac{\tau}{2\mu_0} \left[\frac{a(\lambda + 2\mu)}{2h\mu_0} + \frac{\pi}{4(1 - v_0)} \right]^2 \right\rangle \\ \tau &= \frac{4}{3} \pi a^3 n_0 \end{aligned} \quad (4.34)$$

Figure 5.40 shows the result for the V_{SH} and V_{sv} measured and calculated using effective field method (EFM) in the Upper Cretaceous Tamaulipas formation and Pimienta formation. The crack density has been estimated in both formations to establish V_{fast} and V_{slow} showing differences in velocity Figure 5.41 suggesting that the anisotropy is present in both formations, the higher anisotropy can be observed between (1920-1960m) within Tamaulipas Formation. The angle between the hole axis and the normal to the crack system have been determined as well showing a degree angle according to the crack density estimation Figure 5.42.

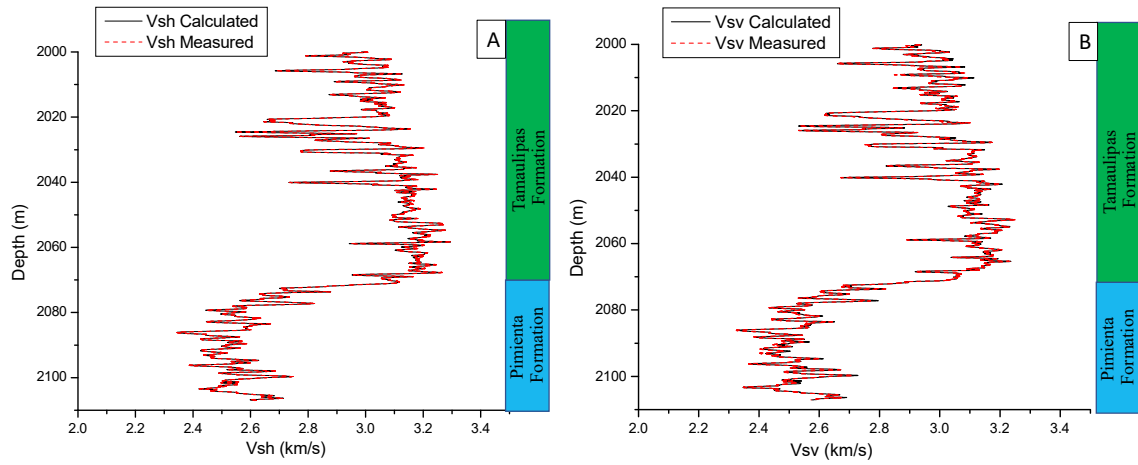


Figure 5.40. V_{sh} and V_{sv} measured and estimated using effective field method (EFM) within Tamaulipas and Pimienta Formation.

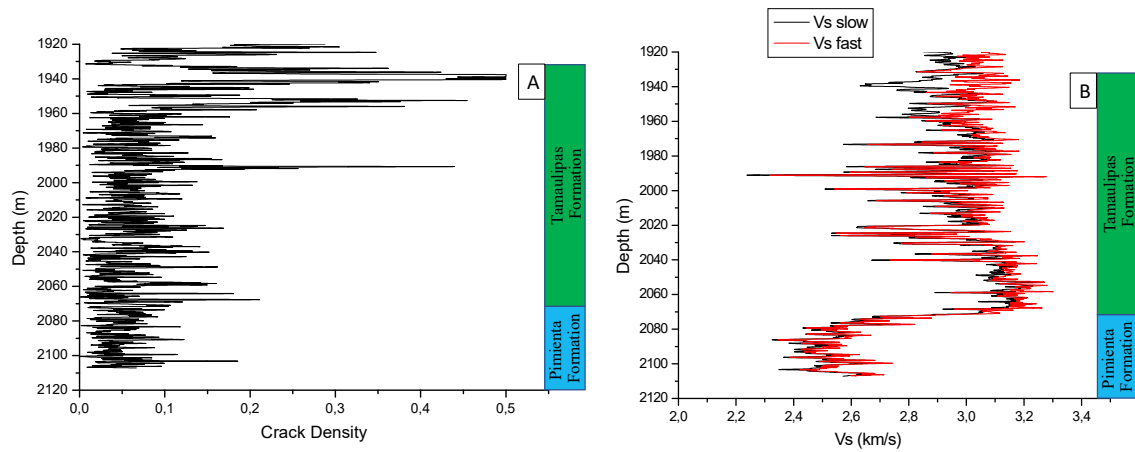


Figure 5.41. A) Crack density log estimation; B) V_{fast} and V_{slow} within Tamaulipas and Pimienta Formation

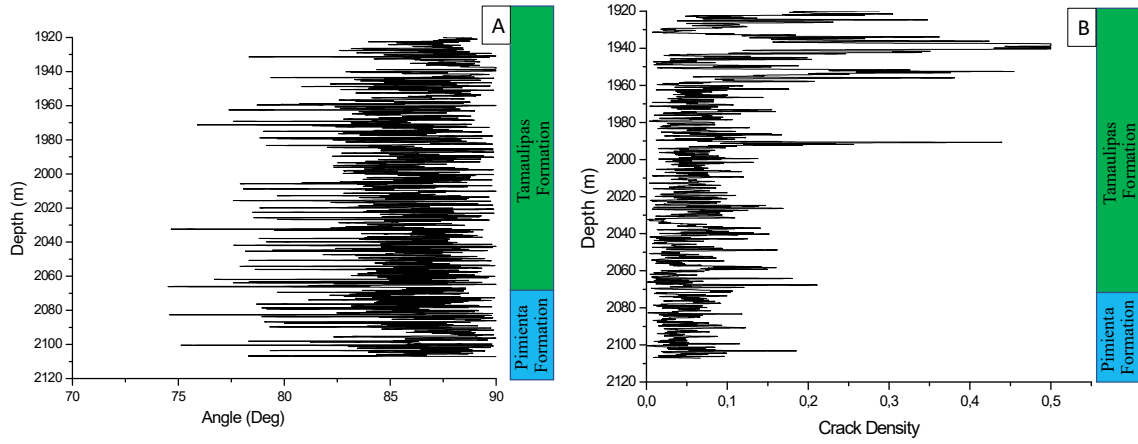


Figure 5.42 Angle between the borehole axis and the normal to the crack system.

To see the correlation of the V_{sv} and V_{sh} using the effective field method the scatter plot (Figure 5.43) shows a very high correlation according with the result in R^2 . Both methods DEM and EFM addressed in this thesis shows very high correlations.

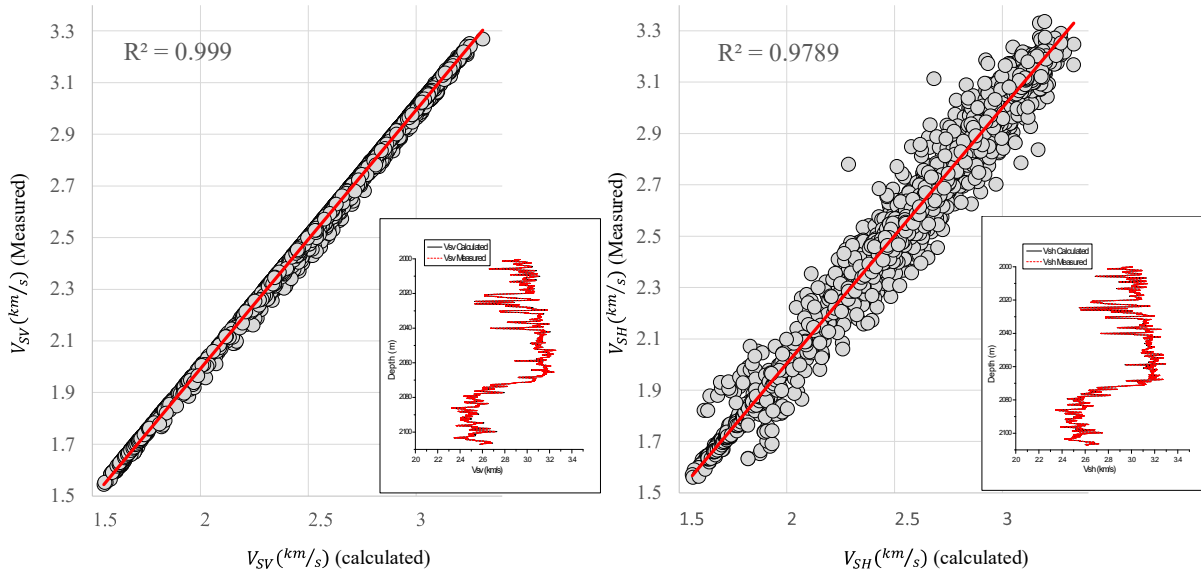


Figure 5.43. Scatter plot V_{sv} and V_{sh} using effective field method EFM and the correlation between measured and calculated velocities.

5.2.6 Description of how attributes were extracted from the data

For Azimuthal AVO *B_{ani}* Map extraction

Analysis of the azimuthal anisotropy plays an important role in shale reservoirs characterization as it can be used to map pre-existing fractures or help in optimal horizontal wells placement. Here I focus on the Pimienta Formation.

The fracture density maps attributes were extracted from the B_{ani} volume of the azimuthal AVO with an investigation window of approximately 80 m from the top of the Pimienta Formation and the top of the Olvido Formation. The extraction of the value of the anisotropic gradient could then be associated with the intensity of fractures.

In order to map the orientation of fractures and the principal stresses, the seismic amplitude of the Pimienta Formation was observed in different azimuths to detect any anisotropy. The data is best sorted in the COCA gather common offset by common azimuth since this allows the extraction of the horizontal transverse isotropy (HTI).

For this case the horizontal transverse isotropy (HTI) model was used. This measures the reflectivity within a fractured layer (Pimienta Formation) underlain by an isotropic layer. For fractured reservoirs it requires an overlapping seal, which in this case is represented by the Lower Cretaceous layer, and this has very high impedance response (Figure 2.5).

The overlapping seal should ideally be relatively homogenous so that the anisotropy results in HTI media can be explained by Thomsen parameters ($\epsilon^{(v)}, \gamma^{(v)}, \delta^{(v)}$). 'v' represents the vertical velocities and are used as reference. The Thomsen parameters measure the degree of anisotropy and are dimensionless and isotropic when all these parameters are zero.

The top reservoir (Pimienta) represents the source rock and has regional areal extent. The B_{ani} response changes quickly in the lateral direction (Figure 5.44). It provides the geological basis for fracture reservoir prediction. The target layer average thickness is about 80m. The reservoir thickness about 80 m is higher than $\lambda/4$ (about 46m in this area and tuning thickness about 36m) (Figure 3.7).

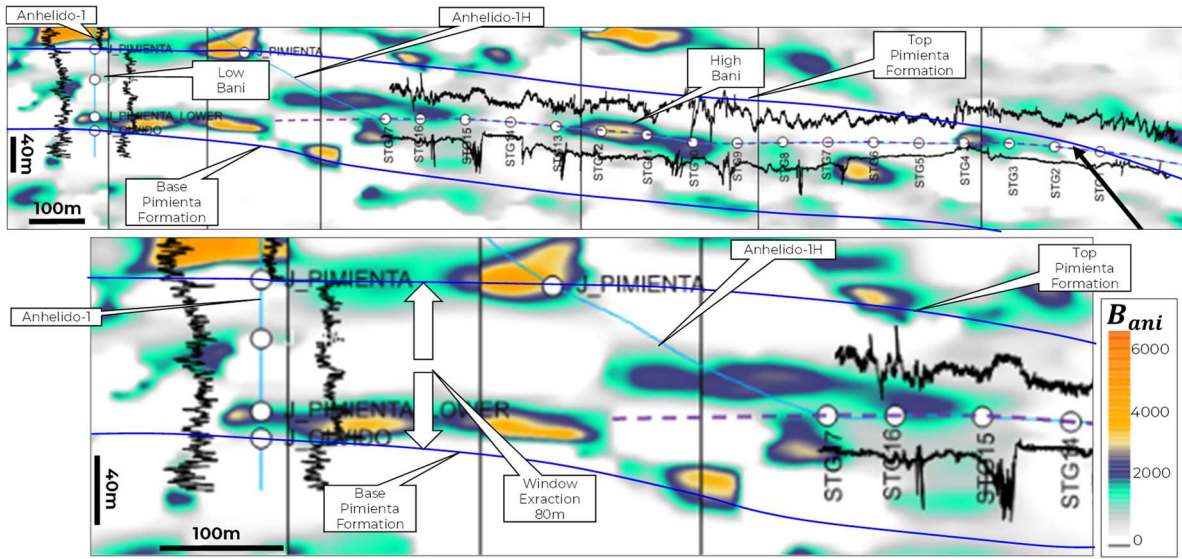


Figure 5.44. Lateral view of horizontal wellbore Anhelido-1H and the extraction window of B_{ani}

The seismic information is conditioned, and azimuthal seismic attributes are generated that contain the magnitude and orientation. This process is carried out for each CDP where, according to Rüger, the following attributes are estimated: There are four main terms of the (eq. 5.41); (A_{iso} , B_{iso} , B_{ani} and ϕ) (Figure 5.45)

A_{iso} Intercept

Isotropic gradient B_{iso}

anisotropic gradient B_{ani}

isotropy plan direction ϕ

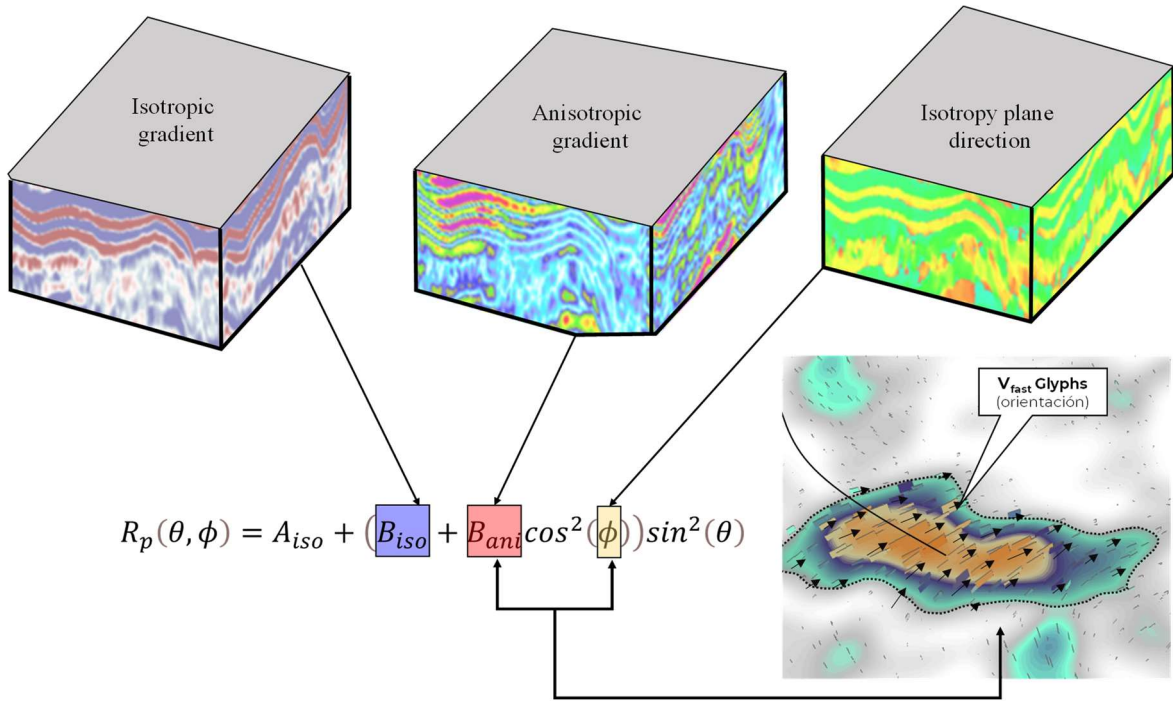


Figure 5.45. Terms obtained in Rüger equation where B_{ani} is related the fracture density and isotropy plane direction ϕ the azimuth volume; when these volumes are combined it can estimate the glyphs (vector distribution of possible fracture orientation) which is related to the direction of fast velocity or stress.

According with the (eq. 5.1) Rüger style can be written in linearized manner (Xu and Li, 2002), such that:

$$R_p(\theta, \phi) = A_{iso} + (B_{iso} + B_{ani} \cos^2(\phi)) \sin^2(\theta) \quad (5.41)$$

$$B_{ani} = \frac{1}{2} \Delta \delta^{(v)} + 8 \left(\frac{\bar{\beta}}{\bar{\alpha}} \right)^2 \Delta \gamma \quad (5.42)$$

The azimuthal angle (ϕ) is the difference between the source-receiver azimuth and one of the model parameters that is to be inverted for ϕ_s . The other model parameters are A_{iso} , B_{iso} , and B_{ani} . The objective function is the sum of the square of the differences between the measured data and theoretical data, $R_p(\theta, \phi)$, modeled using Rüger (1998) for the AVAz done in this thesis.

For penny-shaped cracks model (Hudson, 1981), B_{ani} can be proportional to the crack density, as shown by Figure 5.46. For simplicity, this rock physics model is often used by industry; I do so here.

The ambiguity in inverted symmetry axis can be resolved by some priori information, such a rough estimate of B_{ani} or knowledge about symmetry axis directions (Rüger, 1996).

Higher anisotropy is shown along the horizontal wellbore side around Anhelido-1H however in Anhelido-1 shows lower values (Figure 5.44). The AVAz volume using near-offset Rüger equation show Bani as anisotropic gradient and the orientation of the isotropy plane.

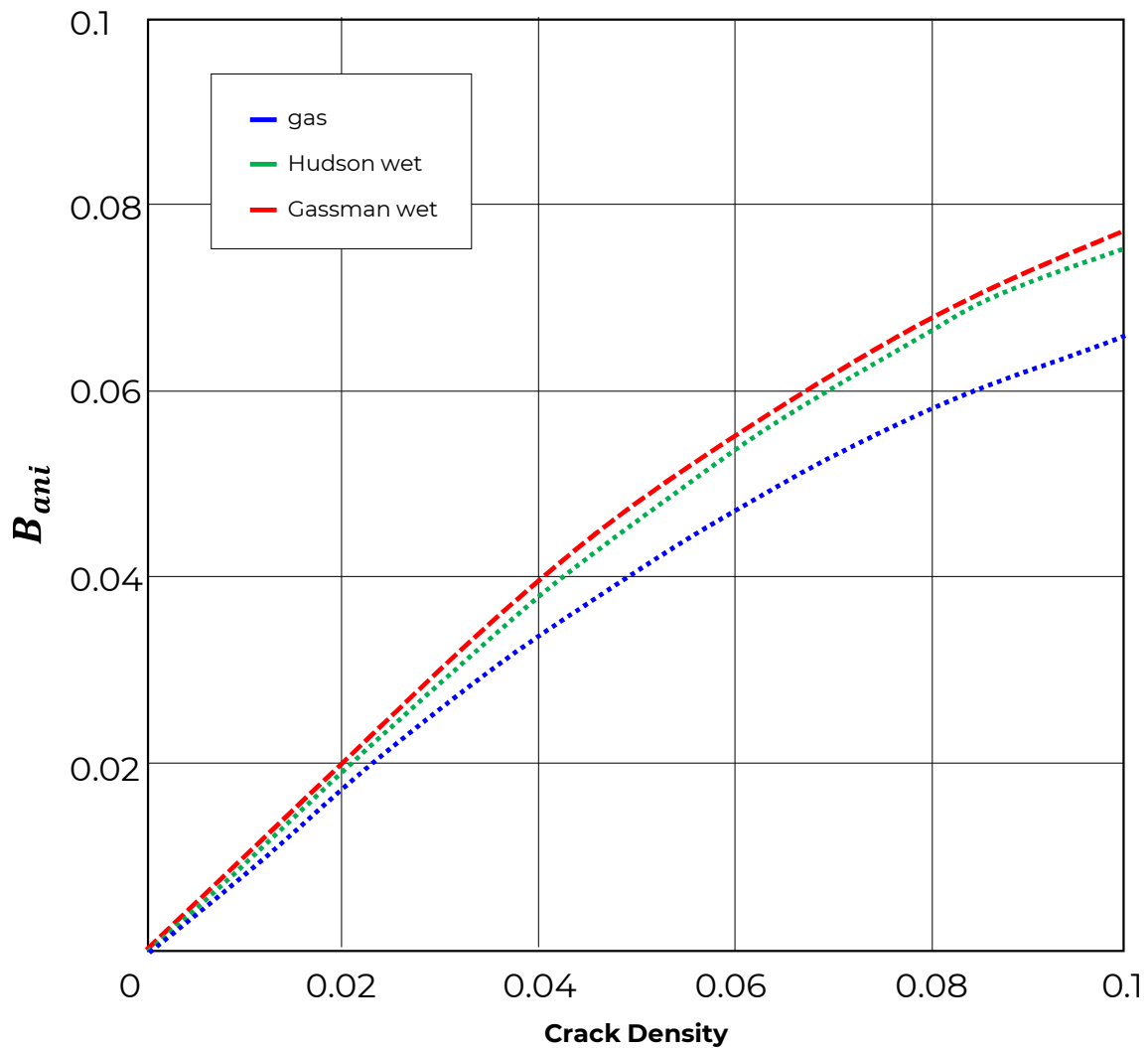


Figure 5.46 Relationship between Crack density and B_{ani} .

To test the algorithm, a synthetic gather was created using the velocities and densities from well logs. The synthetic gather is displayed on Figure 5.47. After several iterations of the optimization routine, the isotropy plane was obtained to be 45° . The values for anisotropic gradient and isotropy plane obtained by inversion were identical to the values used for forward modelling of the synthetic data.

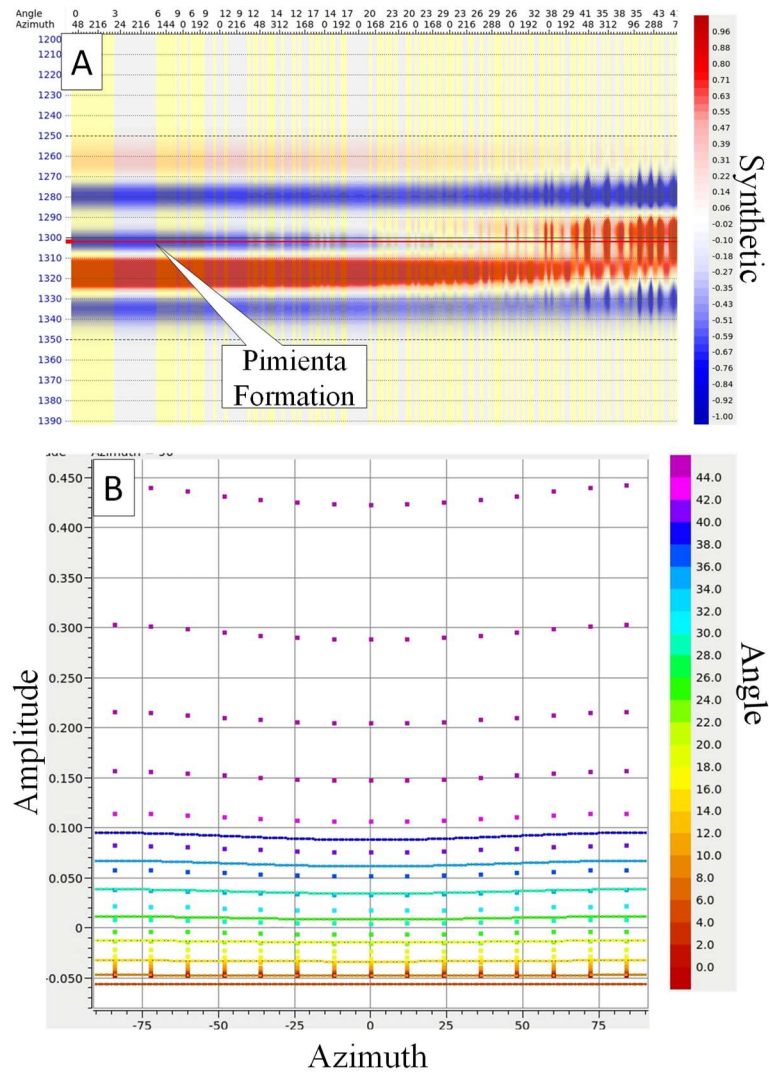


Figure 5.47. Synthetic azimuthal gather created using the velocities and densities from well logs.

In this thesis, AVA inversion (based on a simplified Zoeppritz equation) was used to estimate elastic stiffness coefficients from 3D prestack 360° data acquired at the Pimienta Formation field. These estimated isotropic elastic stiffness coefficients can be useful for identifying sweet spots, i.e., zones of high hydrocarbon potential. In addition, AVAZ inversion (based on a simplified Ruger's equation describing reflections from HTI media) was used to estimate four anisotropic parameters from azimuthally varying reflection amplitudes and NMO velocities. These estimated anisotropic parameters can be useful for estimating fracture density and orientation in subsurface rock formations. An ambiguity exists in the estimated fracture plane orientation. This ambiguity can be resolved by using results of VVAZ inversion as a priori information for the AVAZ inversion. Because, the reservoir of Pimienta Formation is unconventional and fractures play a significant role in production, anisotropy intensity and orientation maps were calculated.

Four snail gathers were performed in the Hampson and Russell software along the horizontal wellbore Anhelido-1H in order to see the residual time travel difference as a function of angle incidence (Figure 5.48). Slightly differences in the fast and slow velocities can be seen. Then a stack angle process was applied to the azimuthal gathers to separate the outputs into four azimuthal sectors (Figure 5.49) for the next step in seismic inversion (addressed in Chapter 6).

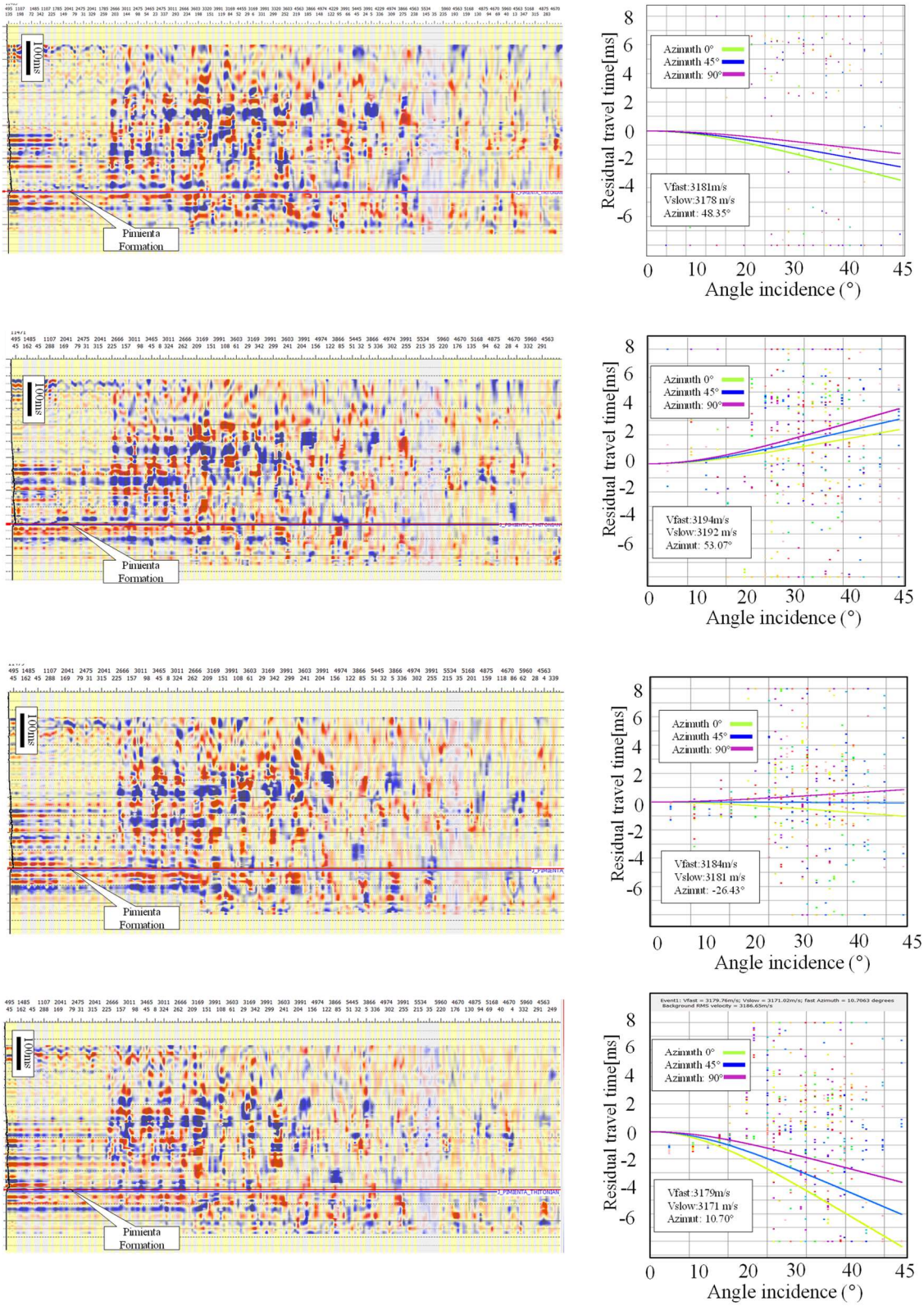


Figure 5.48. Four snail gathers along horizontal side of the wellbore Anhelido-1H to investigate the differences in residual travel time of V_{fast} , V_{slow} and azimuth.

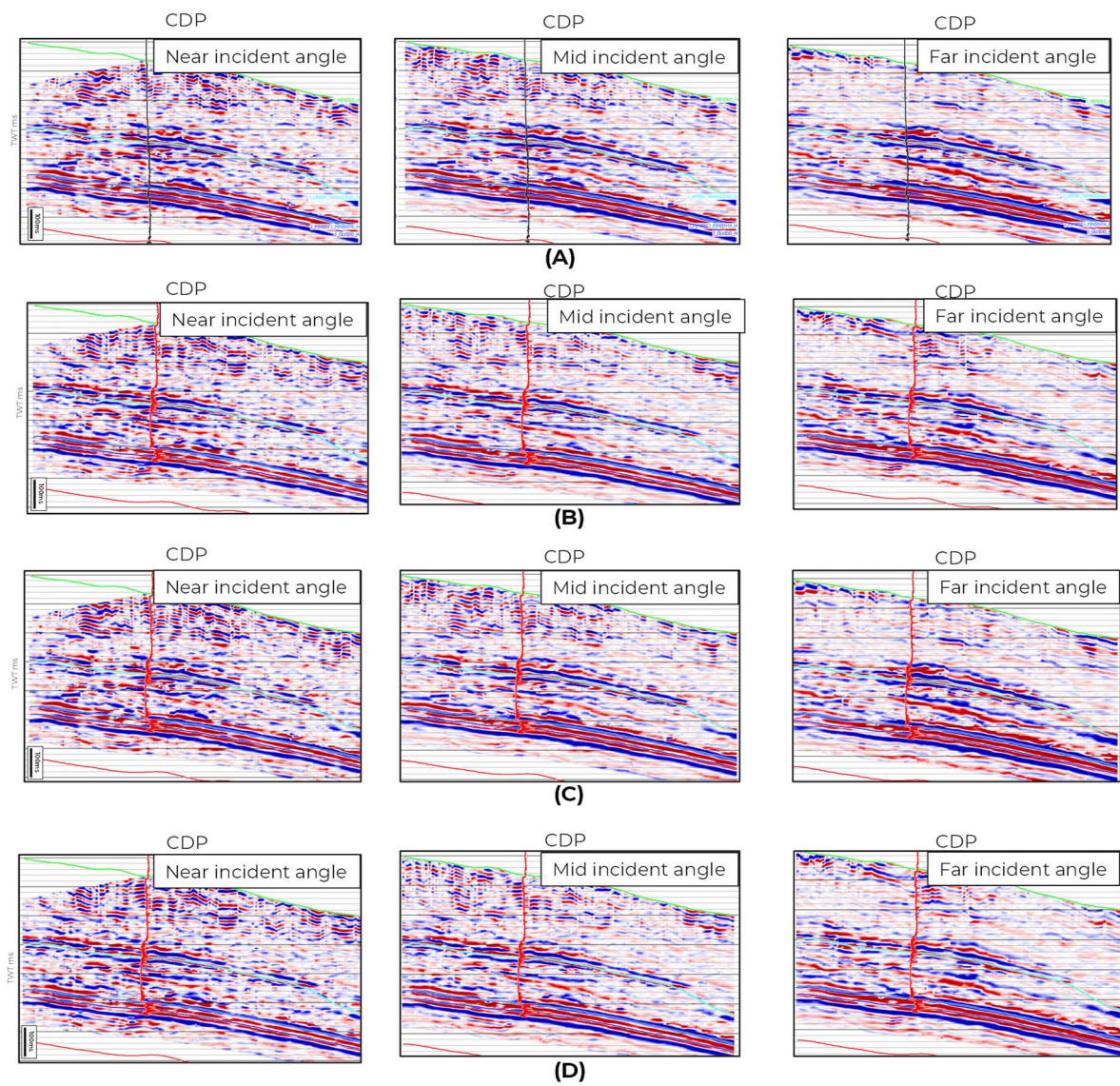


Figure 5.49. CDP angle gather subdivided in near, Mid, and far angle incidence; A) Angle gather sector 1(0-90°); B) Angle gather sector 2(90-180°); C) Angle gather sector 3(180-270°); D) Angle gather sector 4(270-360°).

5.3. Results

5.3.1 AVAz fracture density B_{ani} attribute from azimuthal seismic data within Pimienta Formation

3D surfaces previously interpreted (see section 3.2 Figures 3.2 C) were used in the study area to extract anisotropic gradient attributes B_{ani} related to the fracture density and azimuth A_z in the azimuthal seismic volume within the Pimienta Formation. Based on the Rüger's formulation, I specifically estimated these two variables which are necessary because with the combination of (A_z) & (B_{ani}) as a seismic attribute, it is possible to determine the direction and distribution of 3D fractures quantitatively as vectors.

This attribute combination has not been attempted in any previous study. The combination of attributes was extracted using the 3D surface of the Pimienta Formation with a central extraction window of 80m to obtain the density of fractures corresponding to the shale thickness rock of interest within the Upper Jurassic (Figure 5.50).

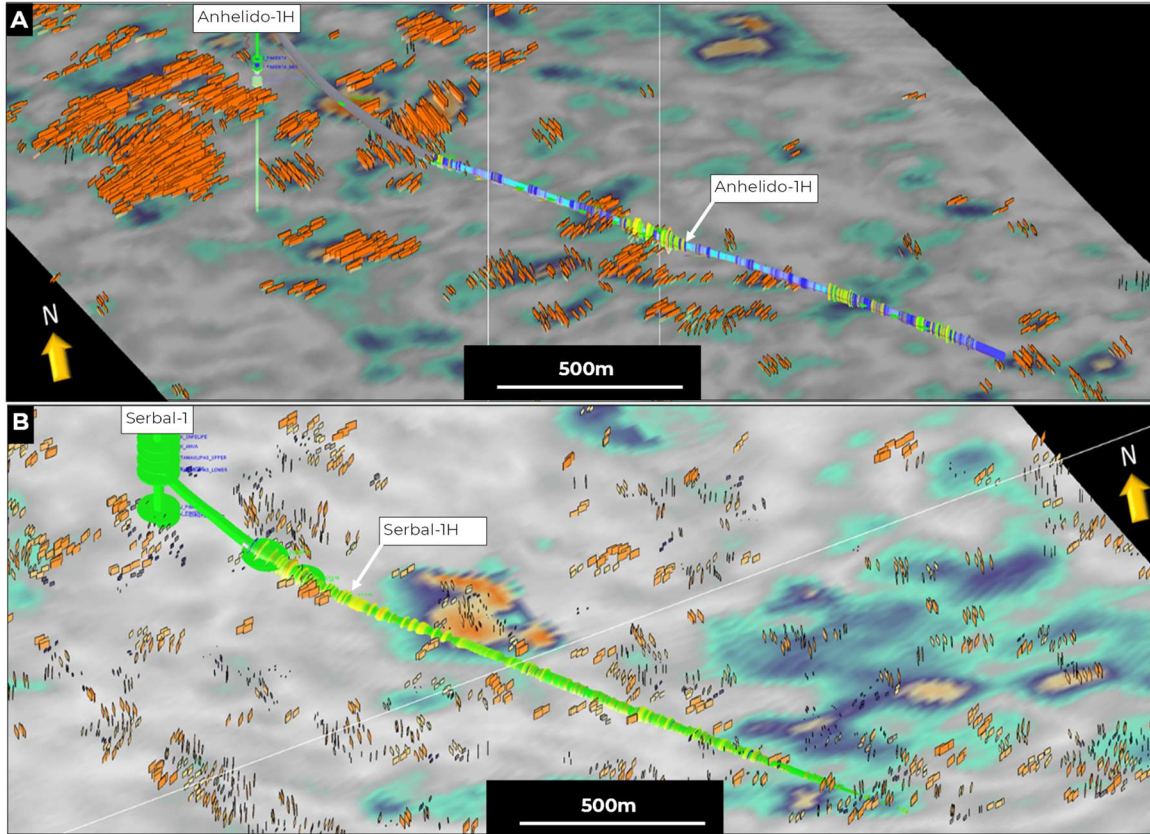


Figure 5.50. (A) Fracture density B_{ani} attribute extracted in Anelido-1 within Pimienta formation with overlapping the fracture vectors as a result of the combination of the azimuth A_z and fracture density B_{ani} ; (B) Fracture density B_{ani} attribute extracted in Serbal-1 within the Pimienta Formation with overlapping the fracture vectors as a result of the combination of the azimuth A_z and fracture density B_{ani} ; Gamma Ray (GR) logs were displayed in horizontal well segments.

Before the attribute extraction of fracture density, I constrained the information using vertical well logs in both wells Anhelido-1 and Serbal-1 to obtain a better estimation of the fracture density maps as well as the constraint in regional stress of the project area. The well-logs used for this constraint were those of P-Wave, S-Wave, and density which gave parameters as follow:

At Anhelido-1 within the Pimienta Formation.

V_p reflectivity standard deviation=0.01672224,

mudrock slope = 1.55508,

mudrock correlation coefficient = 0.886407,

V_p Gardner coefficient = 0.186147,

Gardner correlation coefficient V_s = 0.257903

Gardner coefficient = 0.589703,

Average $\frac{V_p}{V_s}$ ratio = 0.463443

With these values, the Covariance Matrix is calculated, and the AVAz result is constrained which in theory gives a better result for the fracture density estimation (Table 5.4).

	R_{Vp}	$g * R_{Vs}$	R_d
R_{Vp}	1	0.505218	0.18615
$g * R_{Vs}$	0.505218	0.324874	0.0837877
R_d	0.18615	0.0837877	0.0996579

Table 5.4. Values used to constraint the AVAz result of anisotropic gradient this Covariance Matrix describes the amount of variance between V_p , V_s , and density and their correlation using the well-log data from the vertical wellbore Anhelido-1.

The same procedure was applied to Serbal-1 resulting in (Table 5.5).

V_p reflectivity standard deviation= 0.0193711

mudrock slope = 1.03165

mudrock correlation coefficient = 0.449834

V_p Gardner coefficient = 0.0475051

Gardner coefficient, V_s = 0.152146

Gardner correlation coefficient = 0.180837

Average $\frac{V_p}{V_s}$ ratio = 0.483248

	R_{Vp}	$g * R_{Vs}$	R_d
R_{Vp}	1	0.476598	0.11543
$g * R_{Vs}$	0.476598	0.46187	0.0702694
R_d	0.11543	0.0702694	0.167678

Table 5.5. Values used to constraint the AVAz result of anisotropic gradient this Covariance Matrix describes the amount of variance between V_p , V_s , and density and their correlation using the well-log data from the vertical wellbore Anhelido-1.

Using the constraint previously described, I estimated the anisotropic gradient for both wells. These values are calculated taking into consideration the V_{fast} with the isotropy plane. The results are plotted along with the deviation of directional wellbore path as an arbitrary line section in Figures 5.51 and 5.52 for Anhelido-1H and Serbal-1H, respectively.

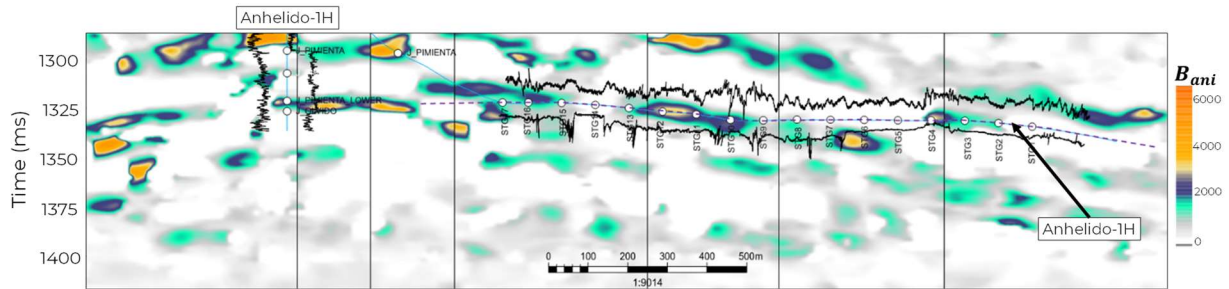


Figure 5.51. Arbitrary line of anisotropic gradient B_{ani} along with the horizontal survey well path in Anhelido-1H, colour code represents the fracture density. The well-path navigation is within the the Pimienta Formation. High values are evident from Stage 9 to stage13 and Stage 15 to stage 17.

Both horizontal wellbores were set up with 17 stages of hydraulic fracture in the well design, and I extracted the values of V_{fast} , V_{slow} , and $V_{background}$ from each stage during the azimuthal AVO analysis (Table 5.6 and 5.7). These velocities were generated from the RMS velocity applied in the migration process. differences in velocities parallel and perpendicular to the isotropy plane are evident that may suggest anisotropy.

(m/s)	STG1	STG2	STG3	STG4	STG5	STG6	STG7	STG8	STG9	STG10	STG11	STG12	STG13	STG14	STG15	STG16	STG17
V_{fast}	3202.9	3209.7	3220.5	3219.5	3218.8	3218.5	3217.9	3225.6	3229.6	3223.	3210.0	3215.7	3224.8	3221.1	3225.1	3224.4	3228.6
V_{slow}	3199.3	3205.5	3215.1	3215.9	3215.5	3216.3	3216.	3224.0	3226.0	3221.	3202.5	3210.5	3220.7	3211.3	3220.9	3220.0	3225.9
V_{back}	3203.2	3196.7	3203.1	3208.2	3212.8	3216.6	3222.2	3225.7	3228.0	3222.9	3212.0	3213.7	3216.0	3214.0	3216.7	3218.1	3221.1
FASTAZIMUT (°)	-9.55	75.81	66.84	-40.85	80.47	-21.96	2.84	52.64	73.00	51.92	-30.10	6.07	-44.31	-80.76	84.68	-19.95	-35.41

Table 5.6 Azimuthal RMS velocity information (Slow & Fast) and the azimuth of polarization of fast velocity in the horizontal wellbore Anhelido-1H for all the hydraulic design stages.

(m/s)	STG1	STG2	STG3	STG4	STG5	STG6	STG7	STG8	STG9	STG10	STG11	STG12	STG13	STG14	STG15	STG16	STG17
V_{fast}	3357.9	3342.8	3353.9	3356.7	3376.2	3392.6	3374.3	3394.8	3390.0	3413.0	3417.4	3402.7	3396.9	3404.7	3395.4	3385.4	3351.9
V_{slow}	3353.2	3340.2	3342.3	3345.6	3365.0	3380.2	3363.2	3379.2	3380.0	3405.0	3410.0	3397.3	3388.9	3399.0	3387.4	3372.9	3351.9
V_{back}	3355.3	3350.2	3346.9	3350.3	3364.0	3370.7	3378.0	3385.1	3391.7	3398.5	3402.0	3396.9	3393.3	3393.1	3388.7	3372.6	3343.8
FASTAZIMUT (°)	38.80	-26.23	10.70	-88.29	67.77	-89.56	16.27	77.71	6.46	41.08	-20.13	-33.46	-33.51	15.69	-10.38	66.26	45.19

Table 5.7 Azimuthal RMS velocity information (Slow & Fast) and the azimuth of polarization of fast velocity in the horizontal wellbore Serbal-1H for all the hydraulic design stages.

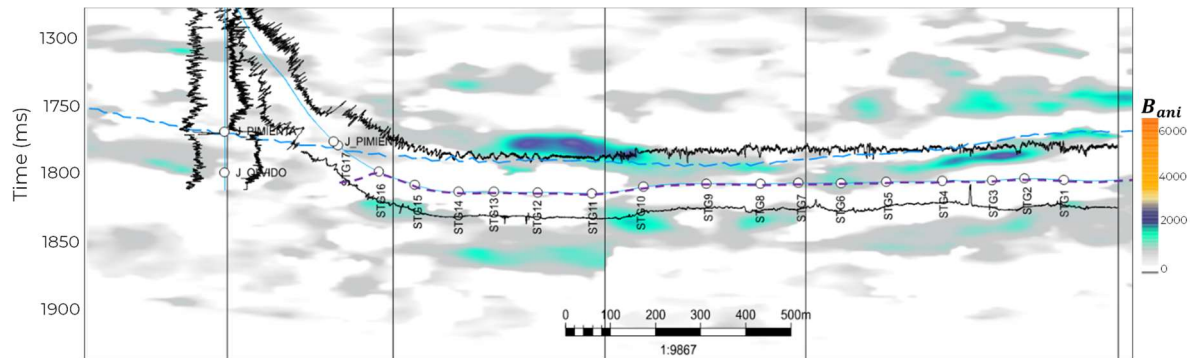


Figure 5.52. Arbitrary line of anisotropic gradient B_{ani} along with the horizontal survey well path in Serbal-1H, colour code represents the fracture density. The well-path navigation is within the Pimienta Formation.

Using the mapped surface of the Pimienta Formation, I extracted the attribute of fracture density from the volume of B_{ani} for both wells around the surrounding areas (Figures 5.53 and 5.54). The extraction used a 12ms time window centred within the Pimienta Formation.

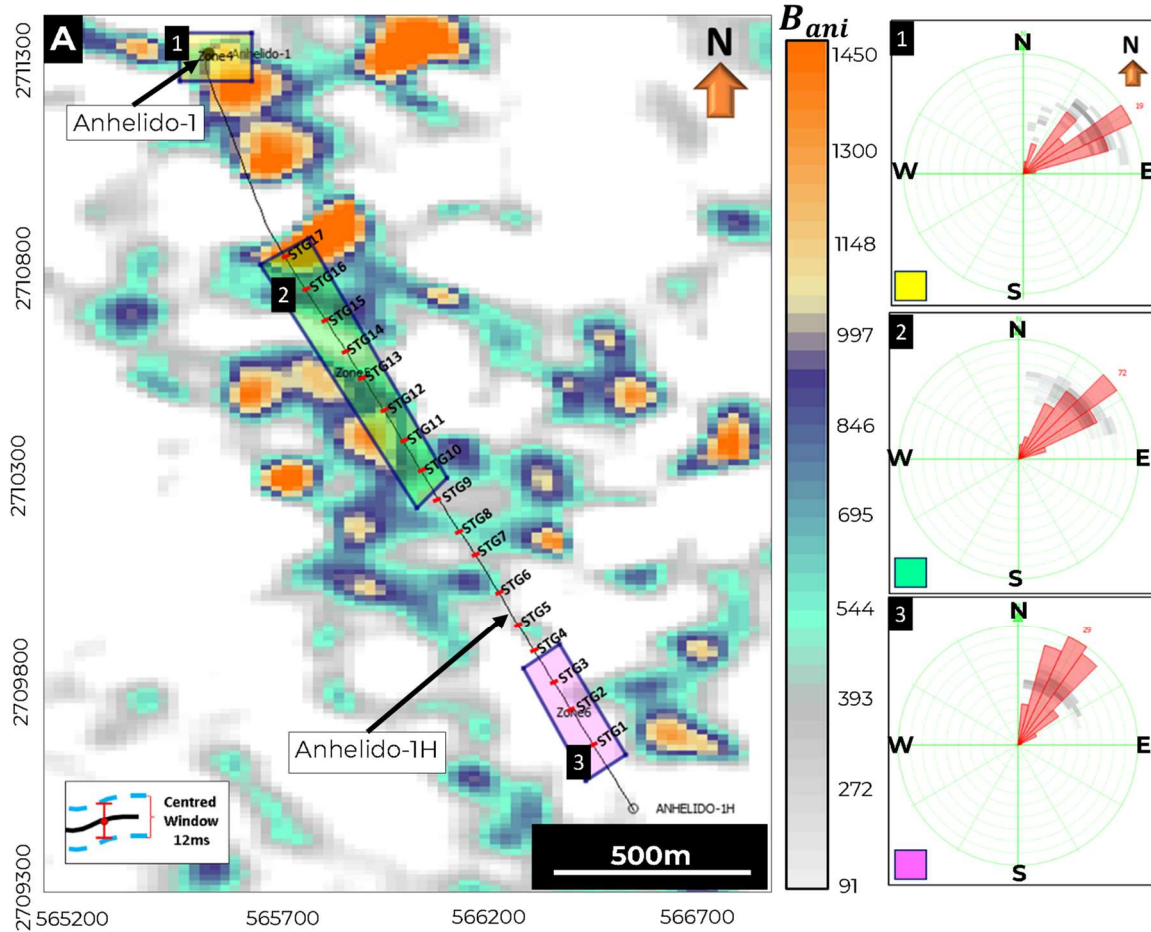


Figure 5.53 (A) Attribute extraction from anisotropic gradient B_{ani} using 12ms centred window using the Pimienta Formation surface within the target zone along the horizontal wellbore side Anhelido-1H; (1) Yellow polygon enclose zone around Anhelido-1 and its correspond rose diagram of fast velocity related to fracture orientation; (2) It is noticed how the attribute is high quantitatively in fracture density from the stage 10 to stage 17 in colour green polygon and its correspond rose diagram of fast velocity related to fracture orientation; (3) From stage 1 to stage 3 in magenta polygon low fracture density is shown. The rose diagram of fracture count (red) in the well shows a dominant direction striking N30 degrees.

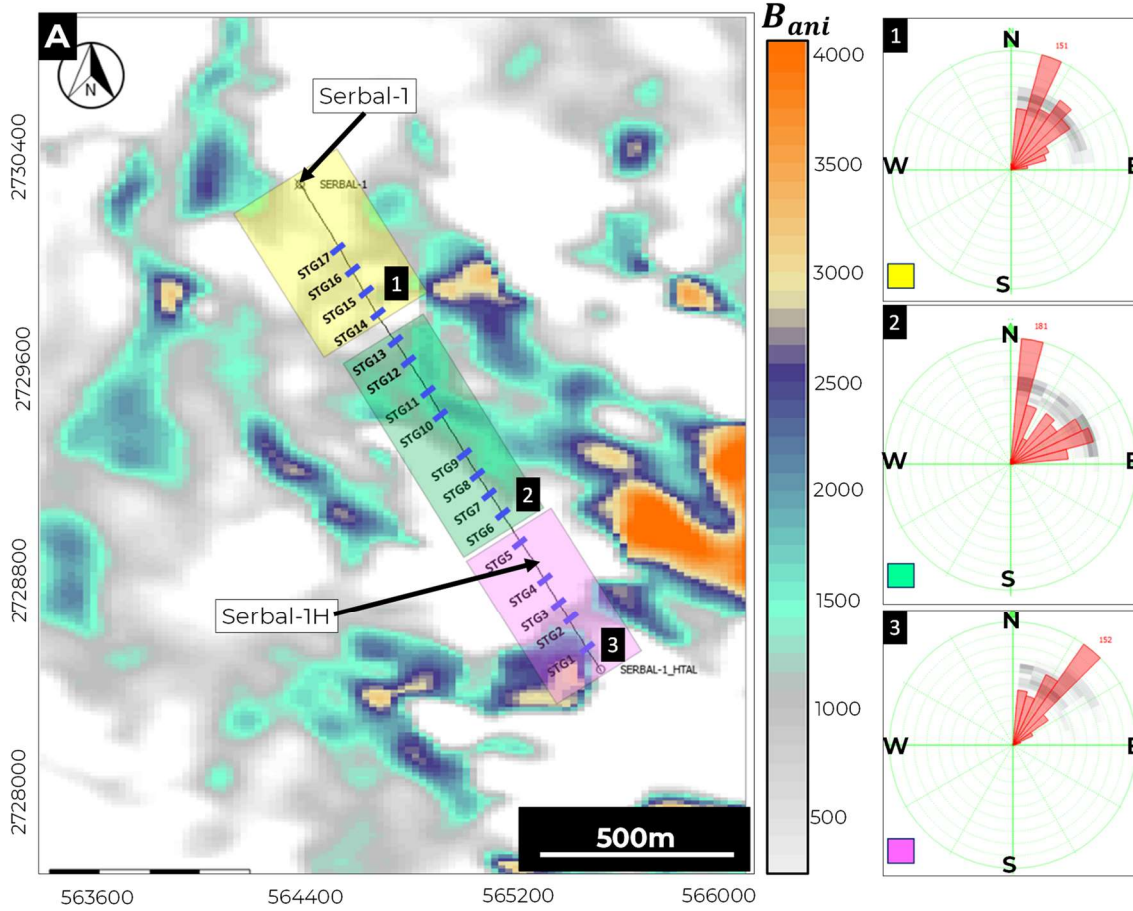


Figure 5.54 (A) Attribute extraction from anisotropic gradient B_{ani} using 12ms centred window using Pimienta formation surface within the target zone along the horizontal wellbore side Anhelido-1H; (1) Yellow polygon enclose zone around Serbal-1 and stage 14 to stage 17 and its correspond rose diagram of fast velocity related to fracture orientation; (2) It is noticed how the attribute is high quantitatively in fracture density from the stage 6 to stage 13 in colour green polygon and its correspond rose diagram of fast velocity related to fracture orientation; (3) From stage 1 and stage 2 in magenta polygon high fracture density is shown. The rose diagram of fracture count (red) in the well corresponding to positions in the horizontal segment are shown labelled 1-3.

5.3.2 Fracture modelling and AVAz comparison

For this procedure I took values derived in Chapter 4 from the crack model from Hudson's theory, and the fractured medium (linear-slip) models where the Thomsen's parameters were used for dry rock, crack density and pore aspect ratio. These same values in (Table 5.8) were used as input data to calculate a model of the azimuthal AVO gather using the Ruger formulation for the HTI medium handled in Hampson and Russell software. The calculation was made for both wells only in the vertical part within the Pimienta Formation (Figures 5.55, and 5.56).

Well	Model	e <i>Crack density</i>	α <i>Aspect ratio</i>	ϕ <i>Crack Porosity</i>	ε	γ	δ	Azimuth(°)
Anhelido-1	Hudson	0.03	0.1	0.02	-0.08	-0.04	-0.07	45
	Linear-slip	-----	0.1	-----	-0.01	-0.05	-0.13	45

Table 5.8: Parameters for modelling in Hampson & Russell software at Anhelido-1.

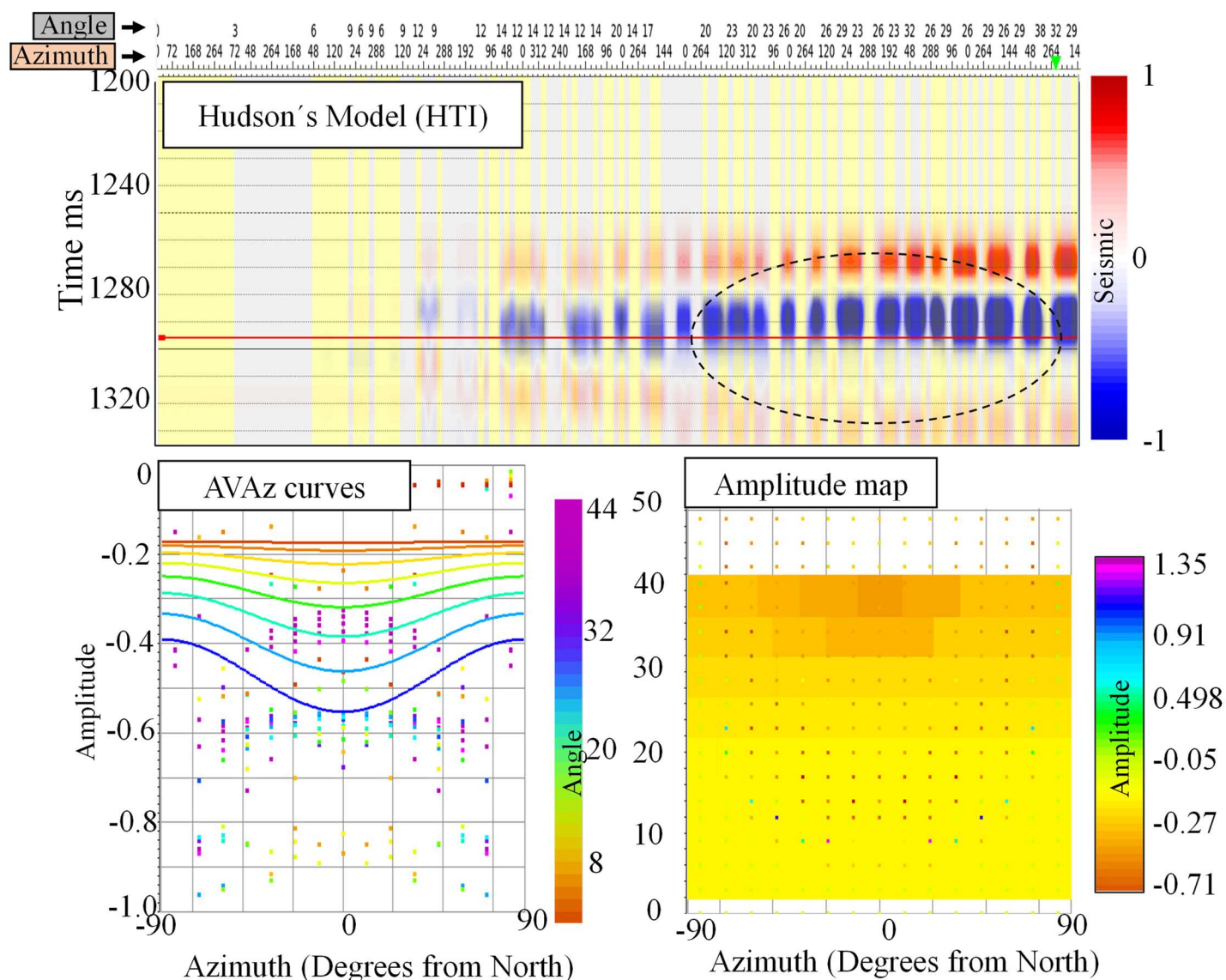


Figure 5.55. (A) Synthetic azimuthal gather at Anhelido-1 depth 2113m generated using the Hudson model based on fracture models listed in table 5.7 it is observed amplitude distortion in far angle incidence (dashed black polygon); (B) Azimuthal AVO curves are created with this model color-coded with incidence angle; (C) Amplitude map variations with azimuth to emphasize the azimuthal changes within the common angles common azimuth gather (COCA).

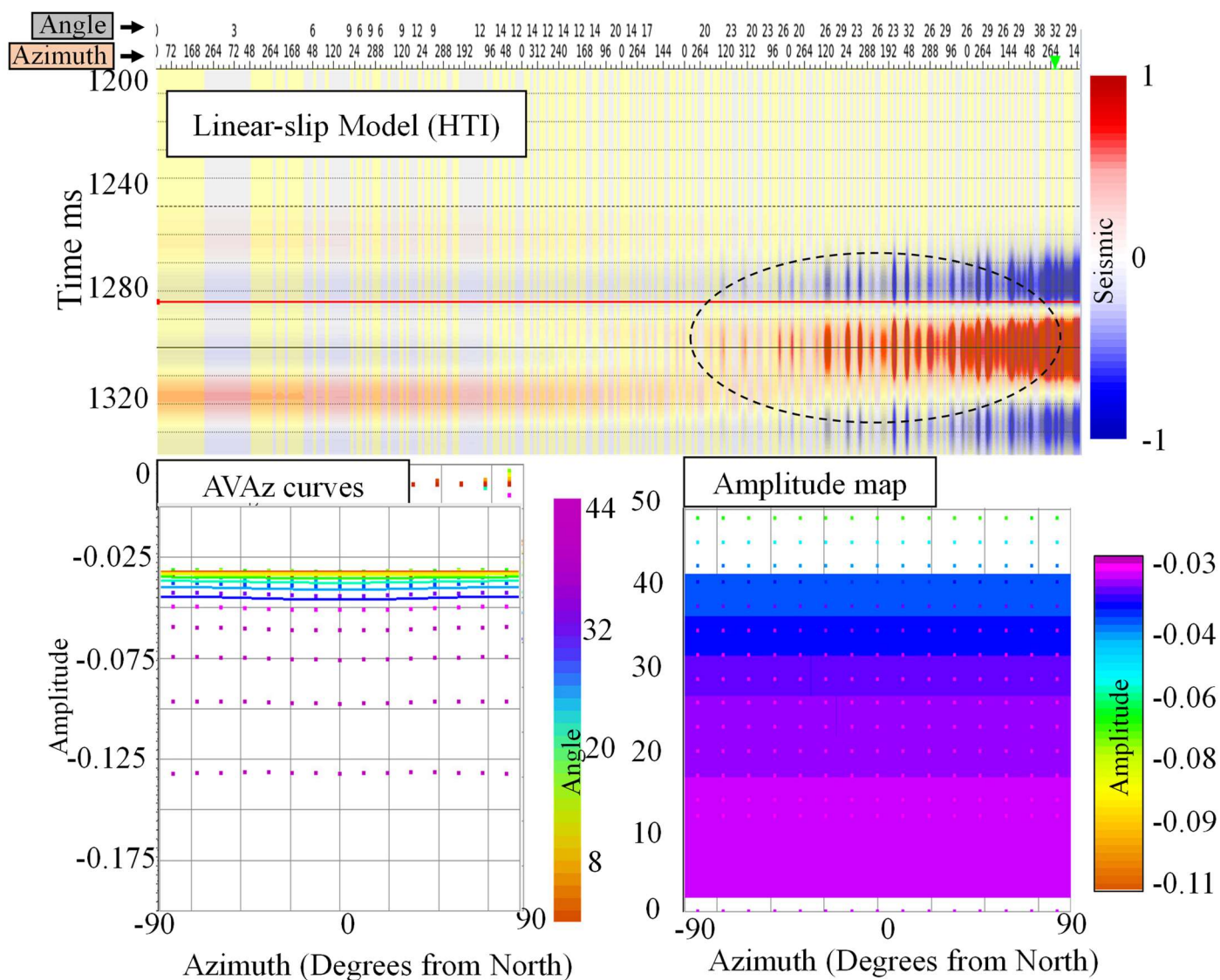


Figure 5.56. (A) Synthetic azimuthal gather at Anhelido-1 depth 2113m generated using the Linear-slip model based on fracture models listed in table 5.7. Amplitude distortion is observed in far angle incidence (dashed black polygon); (B) Azimuthal AVO curves are created with this model color-coded with incidence angle; (C) Amplitude map variations with azimuth to emphasize the azimuthal changes within the common angles common azimuth (COCA).

5.3.3 Microseismic, structural attribute and AVAz combination

The combination of data from different data sources such as microseismic, structural attributes and AVAZ was analysed in the study area of the analogue well (Well-1) to verify the efficacy of the B_{ani} fracture density.

This combination of attributes shows an apparent correlation of preferential direction of possible faults detected by a structural attribute of edge detection (e.g., Ant-tracker), and microseismic data (possible fault planes according to analysis of the microseismic events resulting from the hydraulic treatment). The AVAz attribute or fracture density also exhibits a possible fracture swarm extracted within the Pimienta Formation (reservoir zone ~ 80m) above top of Pimienta Formation (depth 2398m).

For the quantification of fracture patterns, I performed the edge enhancement attribute Ant-Tracker depth slice 25m above the top of Pimienta Formation in well-1 where I converted the depth slice into an image handled in FracPaQ, a new open-source cross-platform toolbox of MATLAB to quantify fracture patterns and compute the fracture orientation (developed by Dave Healy as part of a NERC New Investigator award NE/I001743/1, 2010-2012) (Figure 5.57).

Analysis of the Ant-tracker attribute at different depths was performed and compared with the FMI log (fracture density) within the Pimienta and Taraises Formations for example at 2500m, 2525m (Taraises Formation (Lower Cretaceous)), and 2725m (Pimienta Formation).

For each depth value, a slice was extracted around the vertical Well-1 to see the fracture orientation and its corresponding value in fracture density of the FMI log (Figure 5.58).

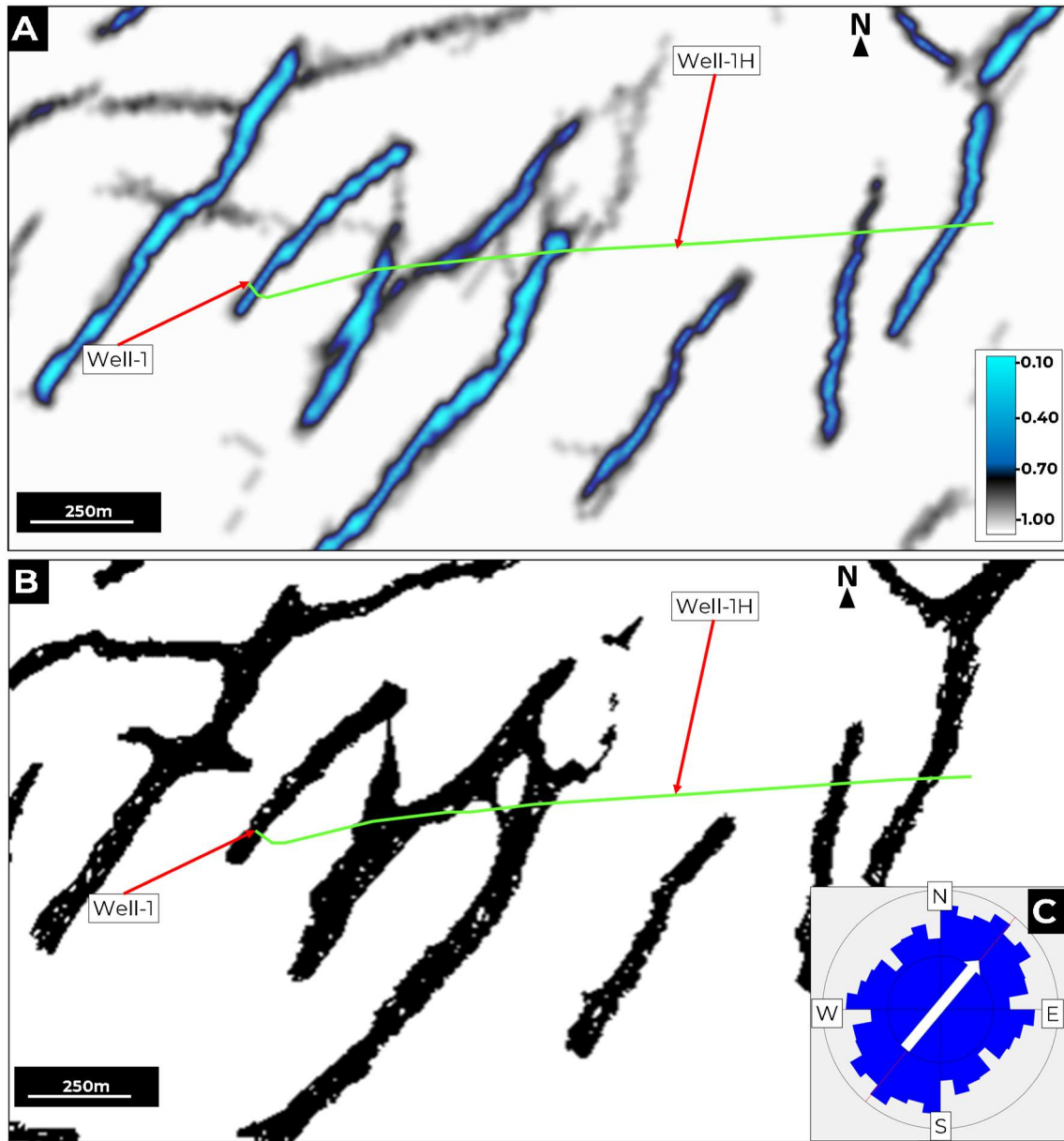


Figure 5.57 (A) Ant-tracker depth slice at top of Pimienta formation (25m above); (B) Image of fracture segments processed and handled in FracPaQ; (C) Rose diagram estimated from ant-tracker attribute and processed in FracPaQ with mean vector fracture orientation (white arrow) (Healy, 2012).

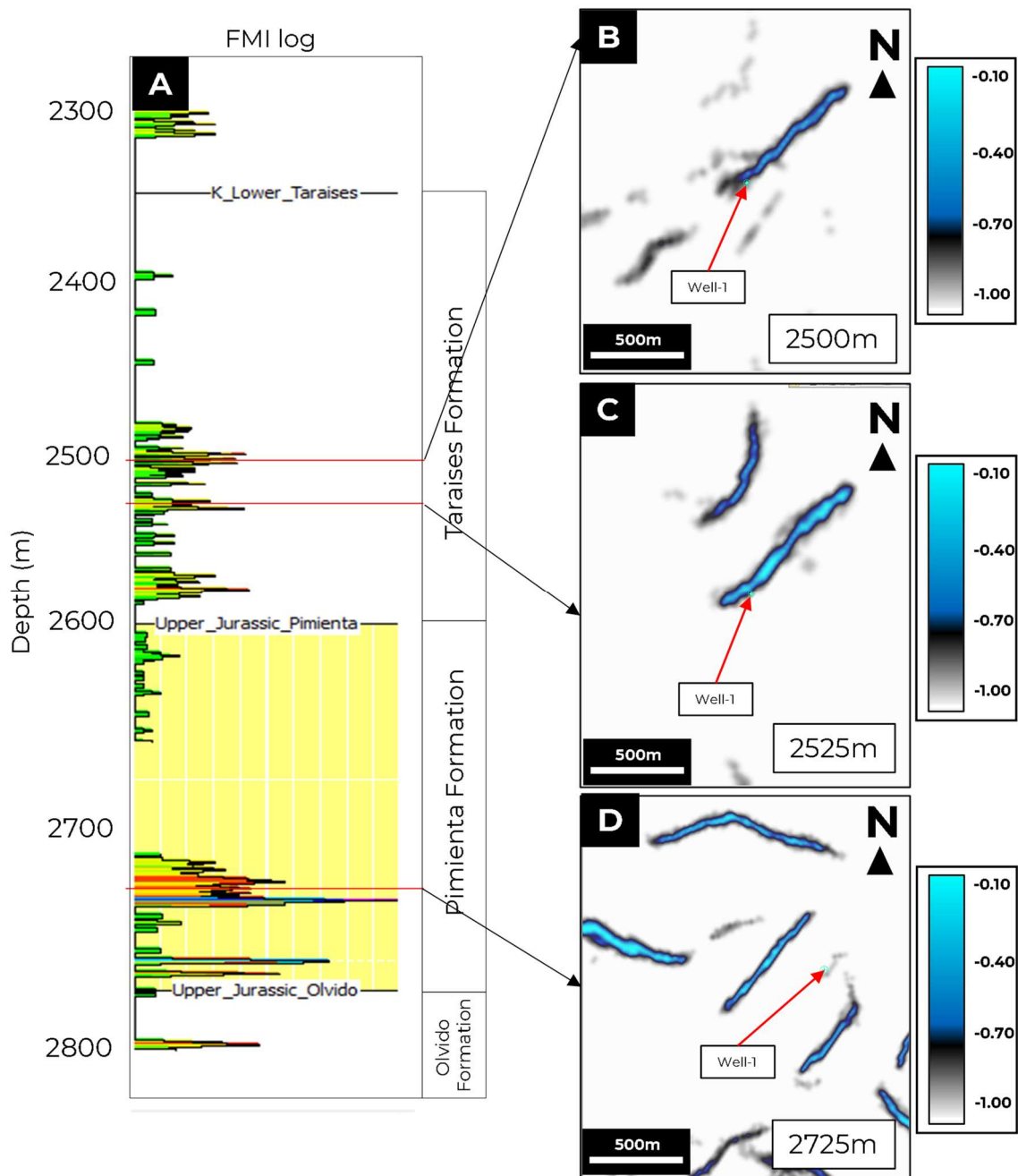


Figure 5.58 (A) FMI log (Fracture Density) at Well-1; (B) Ant-tracker slice at 2500 m within the Taraises Formation; (C) Ant-tracker slice at 2525 m within the Taraises Formation; (D) Ant-tracker slice at 2725 m within the Pimienta Formation.

The dominant fault direction of the Ant-tracker attribute, microseismic events and AVAz within the Pimienta Formation is consistent with the same fault orientation around Well-1 and Well-1H, as seen on the depth slice at 2398m positioned just above the Pimienta Formation (Figure 5.57). This depth

was selected for analysis due to the fact that event locations of microseismic activity were more clustered at this level.

The fracture vector orientation from the azimuthal AVO B_{ani} was overlain on the Ant-tracker attribute display and microseismic event map. From the correspondence in positions it is evident that the fracture vector (glyphs) orientation derived from these three attributes is consistent with the NE dominant fracture orientation obtained from the FMI log (Figure 5.59).

Finally, the Fracture density log (interpreted from the FMI log) is compared with the extracted trace of the anisotropic gradient B_{ani} suggesting a good match and consistency with the breakout evidence from the caliper log (ovality) (Figure 5.60), which again suggests a dominant NE direction.

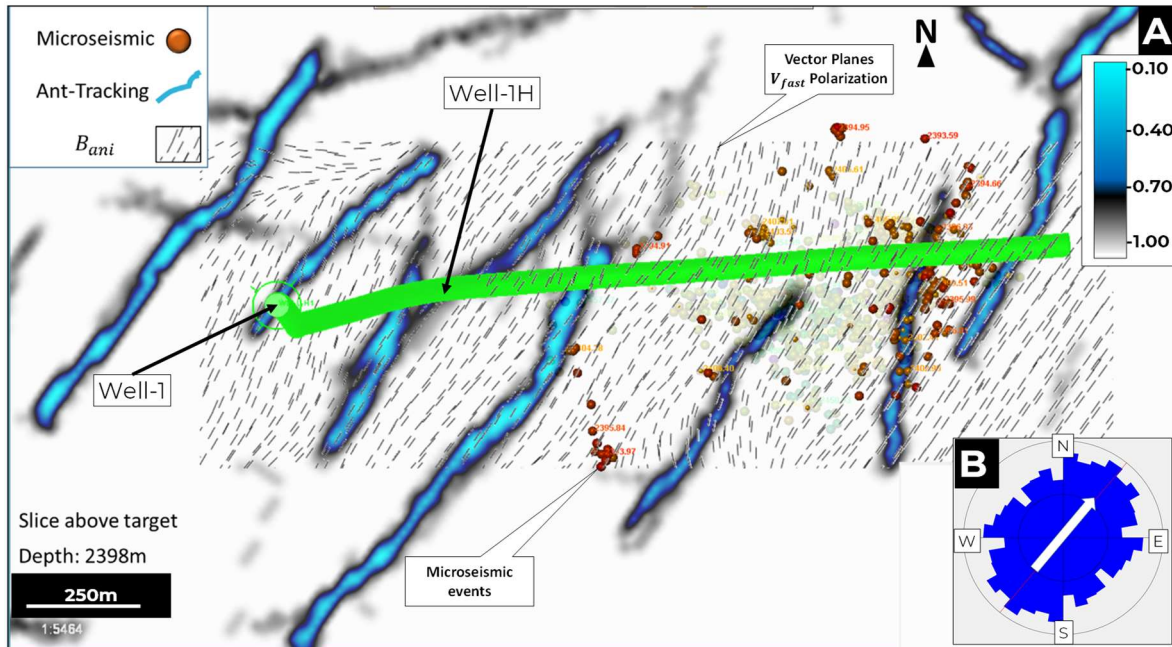


Figure 5.59. (A) Combination of microseismic data at horizontal analogue Well-1H overlain with the AVAz attribute B_{ani} , and ant-tracker attribute. (B) The fault strike data from the ant-tracker attribute, microseismic events, and fracture swarm vectors from AVAz suggest that orientation of faults are mainly NE striking, as displayed in the rose plot derived using FracPaQ open-source MATLAB code (Healy, 2012).

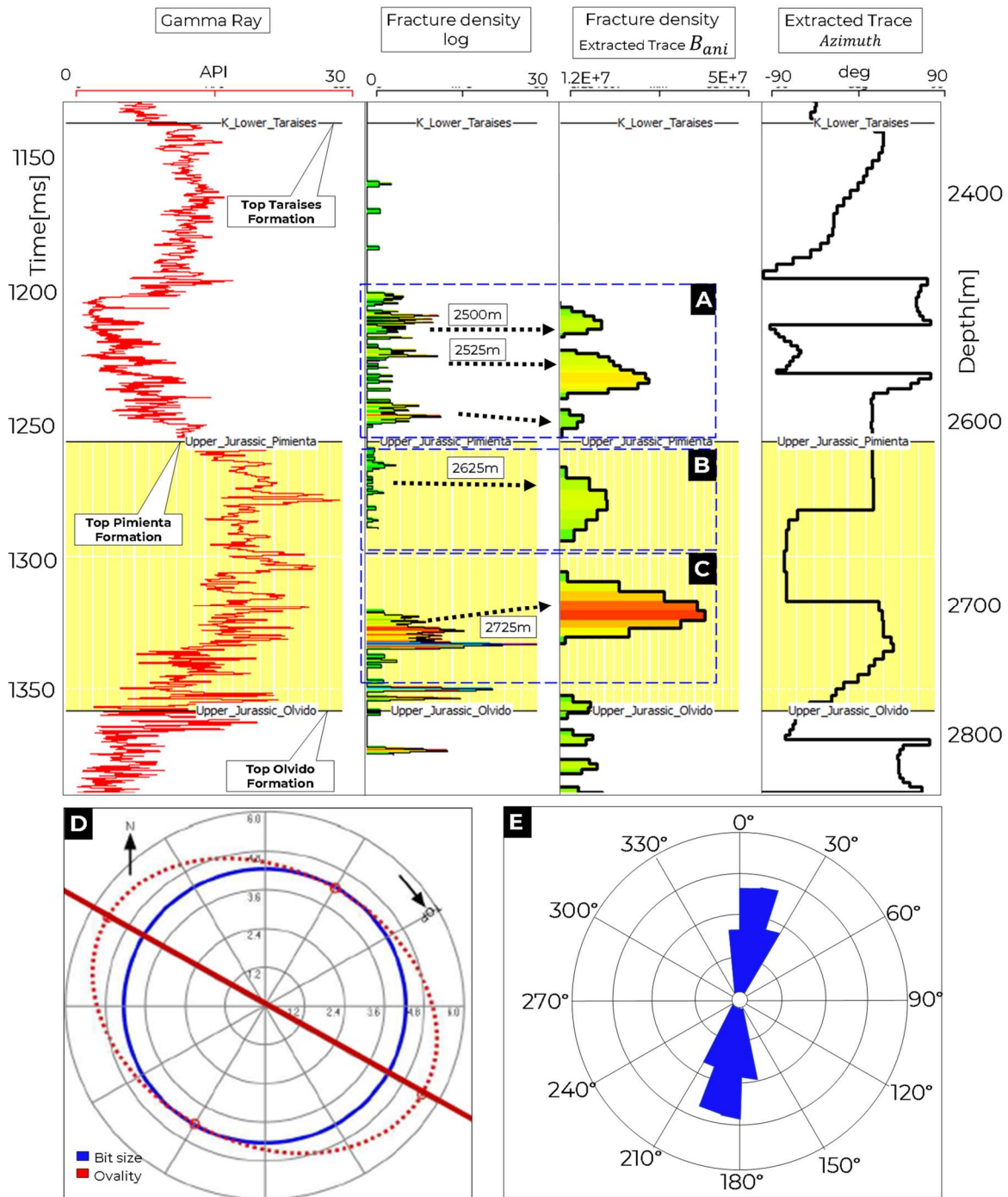


Figure 5.60. FMI log fracture density comparison with extracted trace of B_{ani} at Well-1 within the Pimienta Formation and the Taraises Formation; (A) Fracture density log/Extracted Trace B_{ani} comparison depth (2500m and 2525m Taraises Formation); (B) Fracture density log/Extracted Trace B_{ani} comparison depth (2625m Pimienta Formation); (C) Fracture density log/Extracted Trace B_{ani} comparison depth (2725m Pimienta Formation); (D) Caliper used for measuring borehole ovality within the Pimienta Formation; (E) Natural fractures occur preferentially oriented N-S, with average angles of 67.60 degrees classified as subvertical.

5.3.4 Fluid effect in anisotropic rocks

Studying the existence of fractures in unconventional reservoirs plays a vital role in reservoir productivity and horizontal wellbore drilling design. The seismic velocity is affected by many factors such as temperature, fluid, pressure, porosity, clay content, kerogen, and the degree of anisotropy which can causes errors in the analysis AVO. In this case, the HTI due to fractures may induce anisotropy phenomena.

Based on this background, I have modelled the wave propagation through fractured reservoir as amplitude changes and their elastic constants due to the fluid saturation in a dry model based on the theoretical treatments of Brown and Korringa, (1975). These workers generalized the Gassmann (1951) equation for materials with a heterogeneous solid matrix.

The formulation of Brown and Korringa (1975) contains four elastic bulk parameters which characterize the solid matrix, compared with two parameters (bulk modulus of solid grains and dry matrix) for Gassmann's equation.

For the anisotropic case, Brown and Korringa (1975) proposed an extension of Gassmann's formulation for anisotropy in wet conditions expressed by the equation:

$$C_{ij}^{sat} = \begin{bmatrix} \frac{1}{\frac{1}{C_{11}} - \frac{a^2}{\zeta}} & \frac{1}{\frac{1}{C_{12}} - \frac{ab}{\zeta}} & \frac{1}{\frac{1}{C_{13}} - \frac{ab}{\zeta}} & 0 & 0 & 0 \\ \frac{1}{\frac{1}{C_{12}} - \frac{ab}{\zeta}} & \frac{1}{\frac{1}{C_{22}} - \frac{a^2}{\zeta}} & \frac{1}{\frac{1}{C_{13}} - \frac{ab}{\zeta}} & 0 & 0 & 0 \\ \frac{1}{\frac{1}{C_{13}} - \frac{ab}{\zeta}} & \frac{1}{\frac{1}{C_{13}} - \frac{ab}{\zeta}} & \frac{1}{\frac{1}{C_{33}} - \frac{b^2}{\zeta}} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{66} \end{bmatrix} \quad (5.23)$$

Where

$$\zeta = \left(\frac{1}{K_{dry}} - \frac{1}{K_o} \right) + \left(\frac{1}{K_f} - \frac{1}{K_o} \right) \quad (5.24a)$$

$$a = \left(\frac{1}{C_{11}} + \frac{1}{C_{11} - 2C_{66}} + \frac{1}{C_{33}} \right) - \frac{1}{3K_o} \quad (5.24b)$$

In horizontal isotropy medium the terms a, b are expressed as:

$$b = \left(\frac{2}{C_{13}} + \frac{1}{C_{33}} \right) - \frac{1}{3K_o} \quad (5.24c)$$

The presence of fluid in a horizontal transverse isotropic (HTI) fracture medium results in velocity increasing linearly with the fluid content of the fracture. In theory, the change in velocity is due to the sensitivity of Thomsen's parameter ε to fluid saturation. At same time γ is not sensitive to the fluid saturation because of the C_{55} stiffness variable.

I modelled an azimuthal gather for fluid substitution in Anhelido-1 at the same depth (2113m) for the dry case and for the fluid replacement case (oil/brine) to investigate the amplitude perturbation through the fractures.

Using the Brown and Korrington equation, I estimated the influence of fluid in the fracture compliance or stiffness value which produce changes in the seismic velocity and the Thomsen's parameters, especially in ε and δ . The value of γ does not have any influence during the fluid replacement as it can be seen in (Figure 5.61).

The input data used for the model is:

Anhelido-1

Depth=2113m

V_p (Dry) = 4742 m/s

V_s (Dry) = 3292 m/s

ρ (Dry) = 2.59 gr/cc Moduli

$\phi_{ie} = 0.10$ $K_f = 1.16 \text{ GPa} - \text{Bulk Modulus Oil}$

$K_f = 2.2 \text{ GPa} - \text{Bulk Modulus Water}$

Thomsen's Parameters (dry)

$\varepsilon = 0.06$

$\gamma = 0.02$

$\delta = -0.24$

Reservoir data within Pimienta formation

Pressure = 4809 psi

Temperature = 112.4 °C

API = 37.8 (light oil)

In the resulting synthetic azimuthal model, I chose the far incidence angle at 28° (see Chapter 4) to model the azimuthal amplitude reflection in the dry case and for the fluid substitution case (brine/oil/dry) by applying the Brown and Korrington formulation (Figure 5.61). To implement this computation, I developed a novel graphical user interface for this purpose which is referred to as FluidAnisoMod (Figure 5.64) (Appendix B.2).

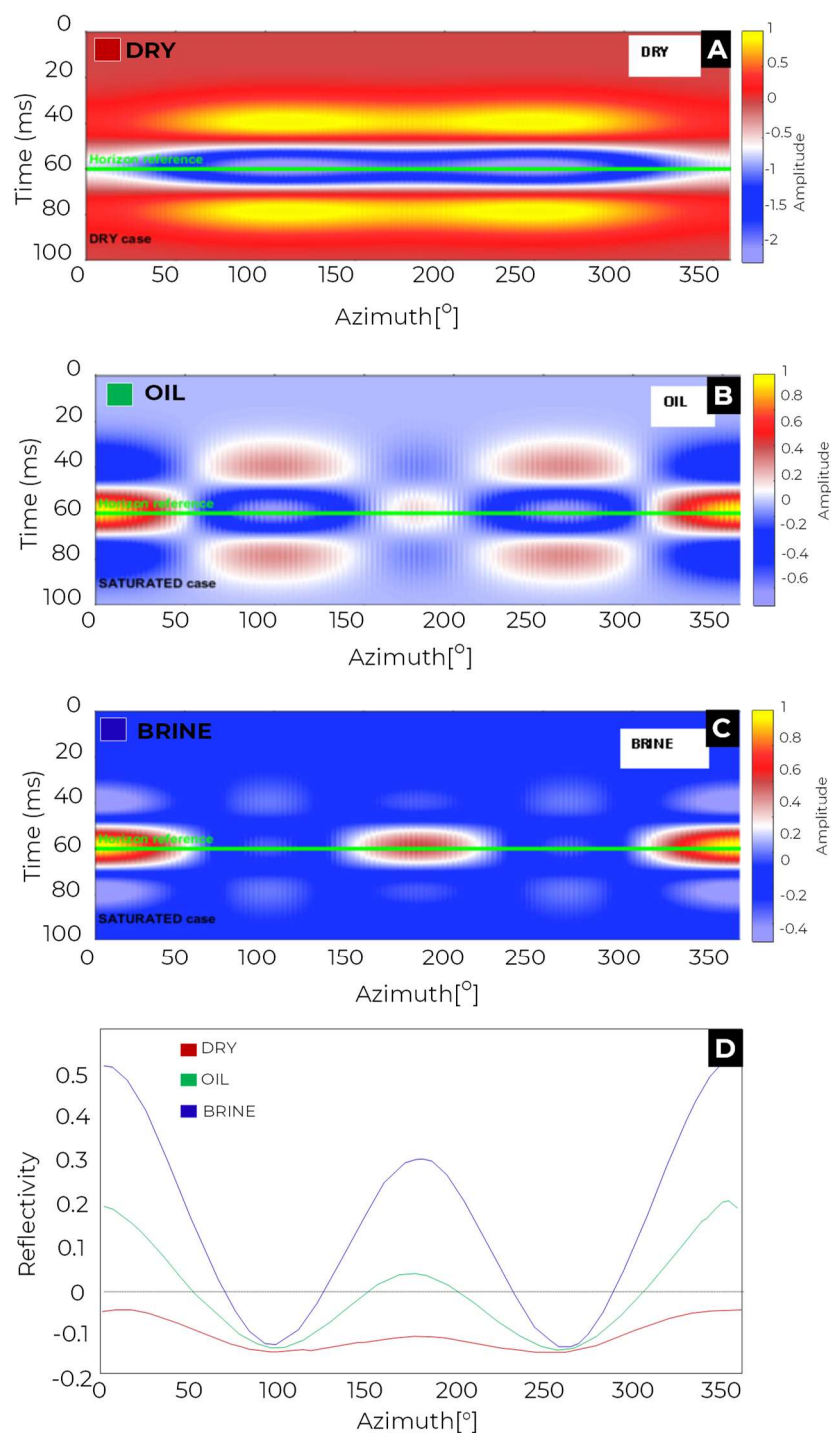


Figure 5.61. Fluid substitution modelling in fracture model as a synthetic azimuthal gather using the Brown-Korringa (Brown and Korringa, 1975) formulation at Anhelido-1 at a depth of 2113m. The green line in the synthetic azimuthal gather indicates the top of the Pimienta formation; (A) Azimuthal gather in the dry case; (B) Azimuthal gather in the oil substitution case; (C) Azimuthal gather in the (wet) brine case; (D) Reflectivity curves as a function of azimuth showing results from all the cases combined.

I performed the analysis at different azimuths to see the response of AVA amplitude vs angle of incidence for oil and water cases. The azimuthal variation can be observed for both cases using this technique. I chose seven azimuths ($10^\circ, 50^\circ, 100^\circ, 175^\circ, 230^\circ, 275^\circ$, and 350°) where I plotted the gradients curves for the Oil and Brine cases. It can be noticed how the oil gradient curve decreases in reflectivity value relative to the brine case (Figure 5.62).

Using the evidence of fracture orientation inferred from the study area (Section 5.3.3) and azimuthal AVO from the seismic data (Section 5.3.1), I compared the response of a real seismic gather at 50° in azimuth and the models carried out by applying the Brown Korrington formulation at the same azimuth. A good match was obtained between the oil and gas case (Figure 5.63) with this method. This modelling was performed through a GUI (FluidAnisoMod) that was developed in MATLAB for this section chapter (Figure 5.64).

However, when comparing this result to those of earlier studies (Guo et al., 2015) offers a method for the characterisation of a naturally fractured system in a reservoir incorporating the squirt-flow model for the prediction of velocity dispersion and attenuation with azimuthal reflectivity method for the calculation of frequency-dependent seismic responses of a fractured poroelastic sandstone layer encased within shale.

It must be pointed out that even better results are achieved using this algorithm since visually, we have the evidence compared to real azimuthal seismic data and shale fluid replacement modelling is addressed in this section.

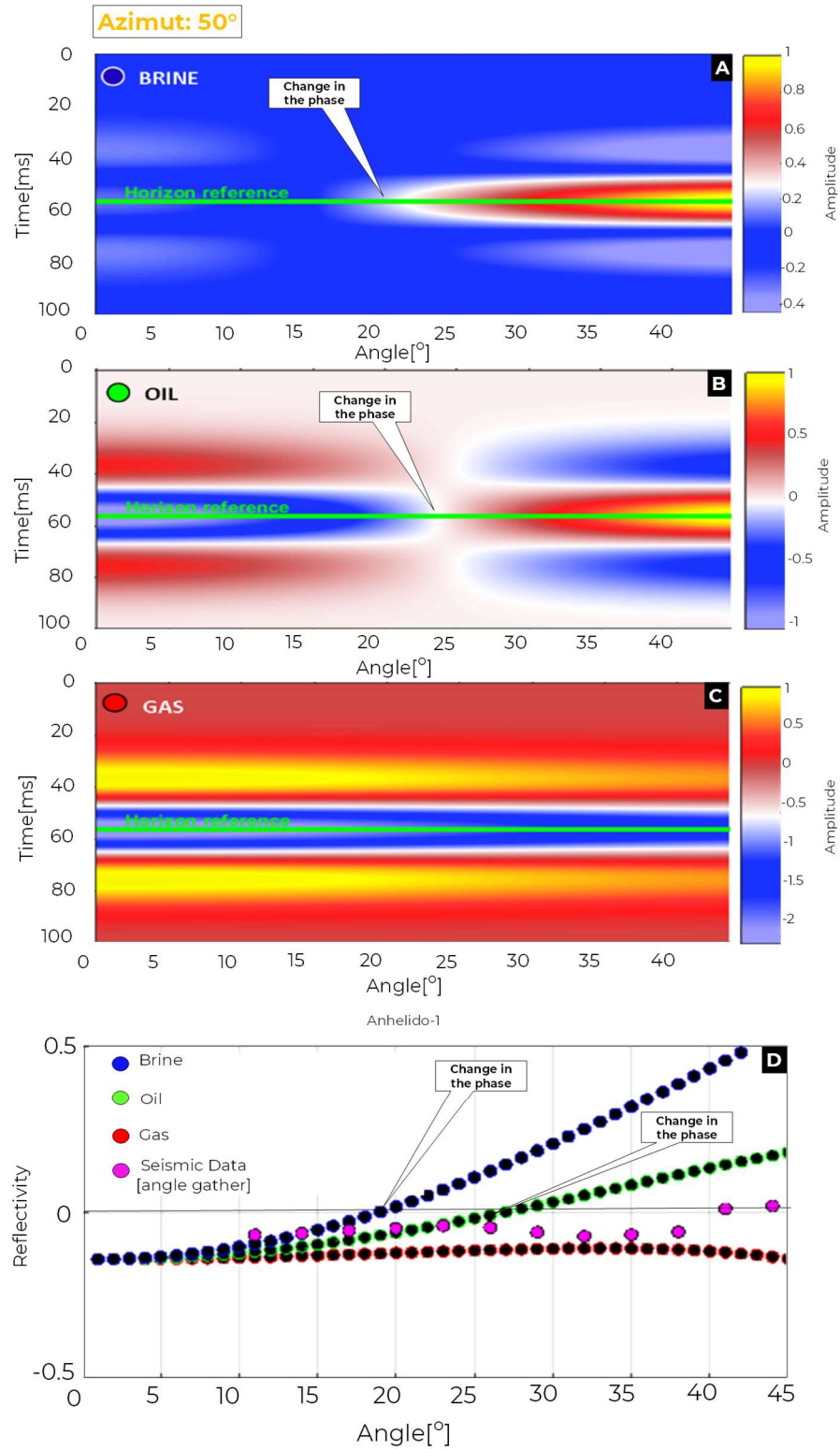


Figure 5.63 AVA Modelling at azimuth 50° ;(A) Brine case; (B)Oil case; (C)Gas case using fluid substitution by Brown and Korringa, 1975; (D) Real angle seismic trace (magenta) displayed over the model values.

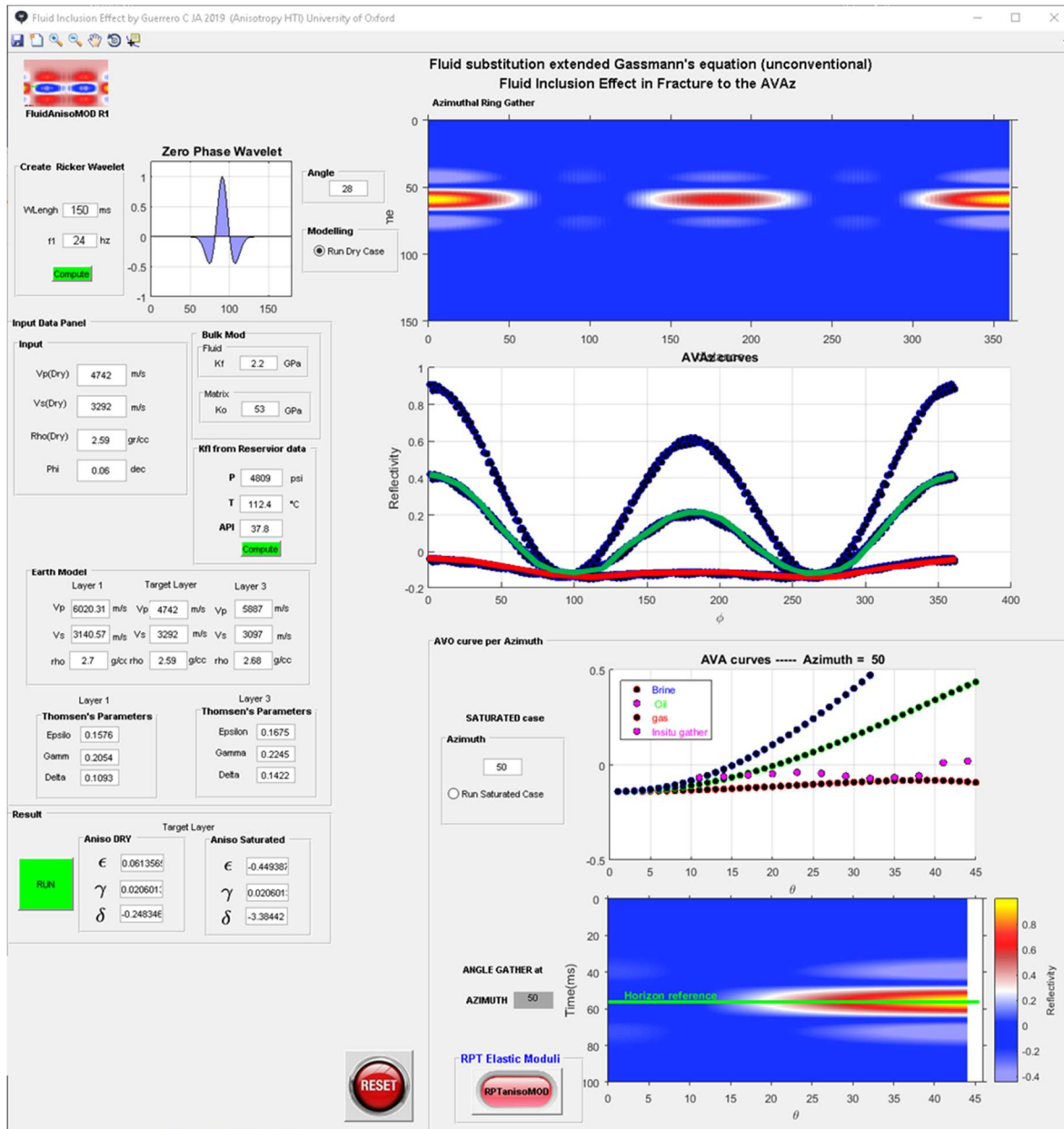


Figure 5.64 Graphical user interface FluidAnisoMod using MATLAB to perform fluid replacement modelling in shale rocks.

5.4. Discussion

In the previous sections different methods for fracture detection within the Pimienta Formation have been applied and anisotropic rock physics analysis undertaken that may potentially explain the intrinsic anisotropy in this shale rock of the Pimienta Formation through AVAz, microseismic observation and the structural attributes used in this chapter. In this discussion, all methods used will be assessed critically in order to build up a strong case to explain the implications of anisotropy in the seismic image for potential hydrocarbon accumulation in shale rocks.

5.4.1 Fracture detection using AVAz within shale Pimienta Formation

The characterisation of fractures in the evaluation of these reservoirs is crucial for the development and design of future drilling wells and it is therefore vital to establish the role that anisotropy plays which should be considered in rock physics templates. With the help of fractured models of effective medium and structural attributes combined, we may be able to explore the impact of anisotropy on the azimuthal seismic image.

The implication of anisotropy in the azimuthal AVO analysis and the synthetic azimuthal seismic image when the fluid replacement modelling is applied on shale rocks is discussed below.

5.4.1.1 Fracture detection AVAz

From the short review in section 5.2, summary of the main observations and key findings emerge:

1. General strong negative seismic reflection response on the top of the Pimienta Formation is seen in the azimuthal seismic gathers according to the different individual CDP seismic

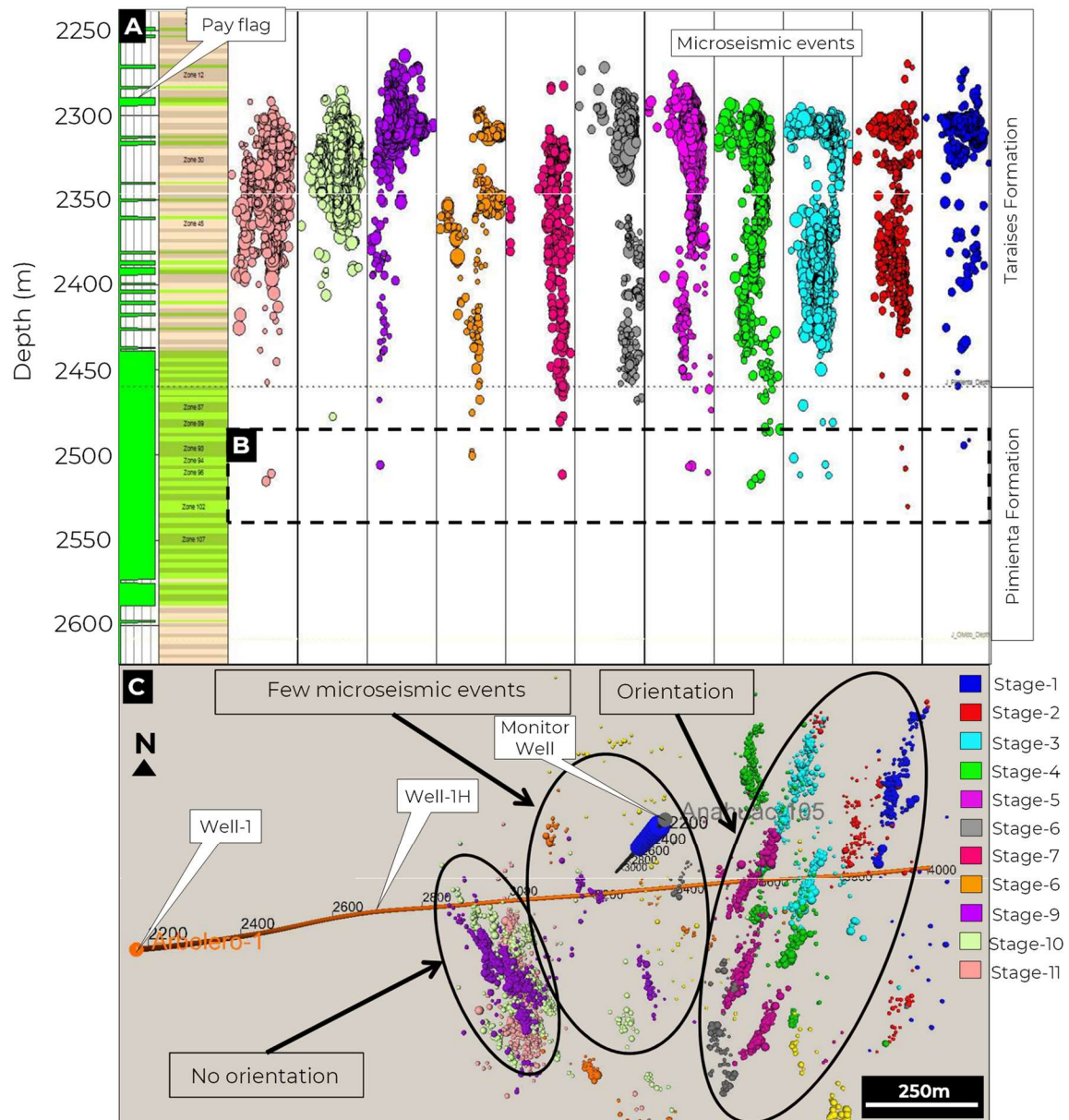
gathers in the wells of the area of study. The wobbling effect seen in every azimuthal gather (section 5.1.2) is consistent and similar responses with previous work that have been described by Rüger and Tsvankin (1997) and Sharma and Chopra (2019) for AVAz analysis. The wobbling effect on seismic gathers (Figures 5.6, 5.7, 5.8, 5.9, 5.10) could be linked with the presence of a set of fractures that may be grouped according with the fracture density maps extracted from the B_{ani} attribute along the horizontal side at Anhelido-1H and Serbal-1H within the Pimienta Formation (Figures 5.53, 5.54). As has been previously reported in the literature, previous research showed similar azimuthal response on seismic gathers (Gray, 2009) that led the to the visualization of anisotropy on prestack seismic data.

2. The present findings confirm that the azimuthal analysis on seismic data carried out in the study area demonstrates the possible existence and distribution of fractures associated with the the Pimienta Formation. The anomalies of fracture density are presented with an irregular shape and the vector planes of the V_{fast} polarization exhibit a preferential NE orientation in the vertical wells (e.g., Anhelido-1 and Serbal-1). The V_{fast} polarization may be due to two key factors: one associated with a population of vertical aligned fractures (macro-fractures) or second, associated with (stress-aligned micro-cracks) caused by the difference in horizontal stresses similar to previous research findings reported on azimuthal anisotropy and the importance of fracture toughness in the estimation of seismic anisotropy and stress orientation in shale formations (Lynn, 2020; Sharma and Chopra, 2020). However, the present-day stress orientation differs from the stress orientation associated with the structural deformation in the geological past (creation of fractures).

3. If the subsurface vertically aligned fractures are filled with fluid, or weakly cemented, the P-wave velocity perpendicular to the set of fractures will exhibit a slow P-wave velocity and fast when its parallel to the set of fractures.

5.4.1.2 Structural attributes and AVAz

1. The computation of structural attributes carried out on stacked seismic data (e.g., edge detection and edge enhancement) variance and Ant-tracker from the analogue study area at Well-1/Well-1H within the Pimienta Formation (Upper Jurassic) and the Taraises Formation (Lower Jurassic) helped the delineation of faults and large fractures presented here which were co-plotted with data from microseismic events and the fracture vectors planes from the V_{fast} polarization. This corroborated the effectiveness of fracture detection using AVAz analysis. The FMI log in the vertical well-1 was then used to validate the fracture density from the extracted AVAz trace (Figure 5.58) and structural attribute Ant-tracker and confirmed a good match at depths of 2500m and 2525m within the Taraises Formation. The sudden jumps in the distribution of microseismic events from the Pimienta Formation to the Taraises Formation may suggest the presence of a possible aseismic fault that is confirmed with the Ant-tracker attribute. A good match was also obtained at 2725m within the Pimienta Formation (Figure 5.58D) (Table 5.9). Because of the interaction of hydraulic fractures and faults according to Maxwell et. al. (2008) when faults interact with microseismic activity, the magnitudes of microseismic events tend to be larger. In contrast when it is small magnitudes suggest a pure hydraulic fracture without fault interaction.



Figures 5.65 (A) Microseismic events along horizontal side of Well-1H; (B) Microseismic events along the landing zone of Well-1H; (C) Top view of the microseismic activity, the color-code represents every hydraulic stage stimulation and the size of the microseismic event is the magnitude.

	Total Events	Post Frac Events	Percentage (%)
Stage 1	926	262	28
Stage 2	1479	209	14
Stage 3	2977	613	21
Stage 4	1601	556	35
Stage 5	3175	838	26
Stage 6	1053	143	14
Stage 7	553	147	27
Stage 8	435	147	34
Stage 9	3510	1218	35
Stage 10	5151	1133	22
Stage 11	3547	1051	30
Total	24407	6317	26

Table 5.9 Information of microseismic events along the 11 stages at the horizontal side of Well-1H

2. The combination of structural attributes, AVAz and microseismic events correlations with these seismic attributes demonstrated the presence of faults and fractures (macro fractures) associated with the Pimienta Formation and part of the Taraises Formation (section 5.3.3). The result of this analysis shows similar results compared with the previous research work by Downton and Chopra, (2010). Analysis of Azimuthal AVO and structural attributes in combination with microseismic events has been applied within the Pimienta Formation for the first time in this research work thesis. This implies that this combination is very important for a better understanding of anisotropy and evaluation in shale rock for unconventional reservoirs assessment.

5.4.1.3 Anisotropic rock physics (anisotropic brittleness)

1. The present study confirmed the findings about the results in rock physics suggest that the kerogen may also induce anisotropy. When I estimated the Voigt and Reuss average bounds there was a dramatic change in the Reuss bound when the kerogen is included that was not

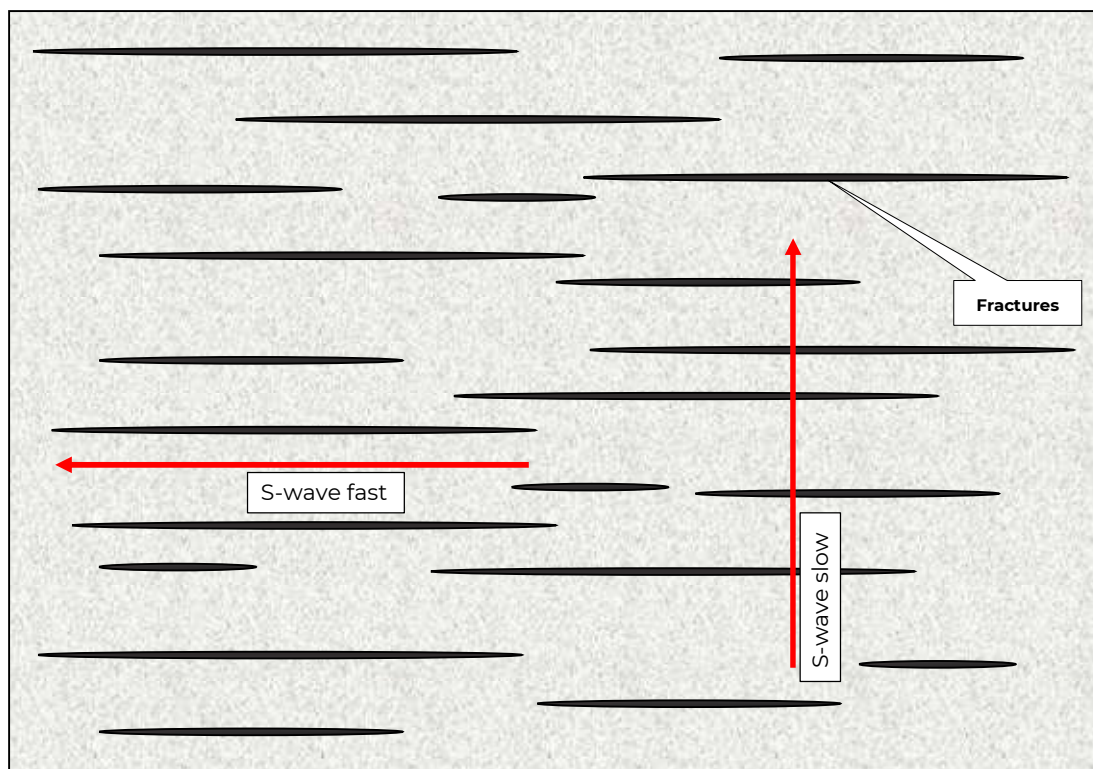
evident by using the mineral components alone. The results also demonstrated the existence of anisotropy within the Pimienta Formation.

2. Several rock physics templates (RPT) were applied to Anhelido-1 and Serbal-1 within the Pimienta Formation. Nevertheless, the best fit was the Friable-Sand Model or “unconsolidated line” from Dvorkin & Nur, (1996) handled in RokDoc software. This model assumes that the diagenetic process leading to the final porosity distribution may correspond to deteriorating grain size reduction but it is unclear whether this is applicable for the Pimienta Formation. In the rock physics template from Mavko et.al. (2009), the Pimienta Formation fits best with the clay-bearing sandstone line (Figure 5.29).
3. The mineral components from X-Ray Diffraction (XRD) are mostly quartz and calcite and not purely dark shale. That may well explain why there is no clear correspondence with the Friable-Shale line (Figure 5.31 and Figure 5.32), and it can be claimed that the calculation is correct even if it does not fit in with the Friable-Shale line.
4. A further novel finding is that the anisotropic brittleness was calculated by adding an extra dimension to the Rickman equation in two directions (vertical BI (0°) /horizontal BI (90°)). The Young's Modulus and Poisson's Ratio were estimated from log data, the results show a notable difference with other research publications (Rickman, 2008), (Wang and Gale, 2009), (Sharma and Chopra, 2013). The applicability of these new results was then tested in this research thesis study using well log data from Anhelido-1 and Serbal-1 within the Pimienta Formation.
5. This result was compared with core samples (Wang, 2009) which are well-matched with the horizontal anisotropic brittleness calculated with this novel approach in this research study. It is worth discussing these interesting points revealed by the results that brittleness might be underestimated or overestimated in shale rock types and go beyond previous reports as shown with the brittleness estimation by other researchers (Rickman, 2008; Wang, 2009; Sharma and Chopra, 2012) using the log data within the Pimienta Formation where there were also

some important differences in the estimation of the brittleness. This novel property of rock has been calculated for the first time within the Pimienta Formation becoming in a new contribution within this geological formation of northern Mexico.

5.4.2 AVAz and rock physics limitations

1. The anisotropic gradient B_{ani} inverted from the seismic data set of the study area can't be proportional to crack density by reason of the band-limited and complexity of seismic/phase data. Rüger, 1997 eq. (5.1) assumes vertical fractures planes in HTI media.
2. Data quality is very important for AVAz analysis amplitude preservation during processing strongly depends on it for better estimation of B_{ani} due to, AVAz analysis is even more sensitive than conventional AVO analysis (Canning and Malkin, 2015). Migration swipes and aliasing noise can be presented in 3D survey wide-azimuth which can create artifacts on seismic image.
3. The limitation of the moduli estimation in the Voigt and Reuss equation is that which assumes isotropic rock, and it is a strict approach.
4. Like any geophysical method, azimuthal AVO has its advantages and limitations. The main advantage is that it uses P waves recorded in a 3D stream to indirectly measure variations in S waves which are those that contain the information on fractures.
5. The methodology of azimuthal AVO is not seismic processing aimed to improve the quality of the seismic information, therefore it is essential conditioning the data by controlling the applied velocities thus reducing the residual NMO problems, eliminate random noises including multiple arrivals and source noise this technology is robust for fracture detection (Gray et.al., 2003). Other confusing aspect is that the azimuthal AVO can only detect seismic anisotropy, (Figure 5.66) that is the fractures are oriented in a preferential direction.



Figures 5.66 Fractures with a preferential orientation produce anisotropy in the velocity of the S waves.

6. AVAz inversion can be extended from conventional AVO inversion methodologies, however, inclusion of anisotropy and azimuthal dimension introduces uncertainties. Approximations and assumptions simplify the problem but hurt the accuracy of inversion. Further studies are conducting to reduce the errors from the uncertainties.

5.4.3 Discussion of the concept of anisotropic brittleness- what does this really mean and the limitations of the brittleness index

Young's modulus, Poisson's ratio, and fracture excess compliances, which are related to rock brittleness and natural fractures, can be used to evaluate the hydraulic fracturing potential of a prospect or area and help identification of the optimized sweet spots in unconventional reservoirs. I aim to characterize the elastic properties of rock brittleness and compliance from the observable wide-azimuth seismic data via the inversion of Young's modulus, Poisson's ratio. Using the linear slip

model, we first derive the perturbations in stiffness components in terms of Young's modulus, Poisson's ratio, and excess compliances for the case of weak anisotropy and small contrasts in elastic properties across the interface. Based on the relationship between scattering function and reflection coefficient in weakly anisotropic media, we then derive a linearized PP-wave reflection coefficient and an azimuthal impedance equation as a function of Young's modulus, Poisson's ratio, density, and excess compliances. Finally, I develop an impedance variation with incident angle and azimuth inversion method to estimate the Young's modulus, Poisson's ratio, and excess compliances in a Bayesian framework. The approach is implemented in a two-step inversion: azimuthal inversion and estimation of model parameters. A synthetic test demonstrates that the model parameter can be reasonably estimated even when containing moderate noise. A field data set test reveals that the inversion results agree well with the well log interpretation.

The anisotropic brittleness refers to the quality of brittleness with different values when measured along axes in different directions in 3D azimuthal seismic interpretation. The presence of structures such as cleavage, schistosity, foliation, joints, or lamination, and bedding planes can cause such anisotropy of brittleness in the rocks. On the whole, the anisotropy of brittleness is seldom investigated. Hou et al. (2016) investigated the brittleness anisotropy of Longmaxi shale with the bedding angle of 0° , 30° , 60° , and 90° under triaxial compression conditions. Two kinds of stress-strain curve approaches were used to assess the anisotropic brittleness index of Longmaxi shale.

The concept of anisotropic brittleness is related to the calculation of brittleness in two principal directions from Young's modulus (E), Poisson's ratio (ν) addressed in sub chapter 5.2.3.2. For this case the velocities P and S in these two main directions were taken into account.

Two symmetry axes of the shale formation were used in this project e.g ($\theta = (0^\circ, 90^\circ)$) for the estimation of anisotropic brittleness. Here the brittleness $Brit_V$ is in the symmetry axis equal to 0° and $Brit_H$ is in the symmetry axis equal to 90° based on the renormalized Young's Modulus $E(\theta)$ and Poisson's Ratio $\nu(\theta)$ (Figure 5.67).

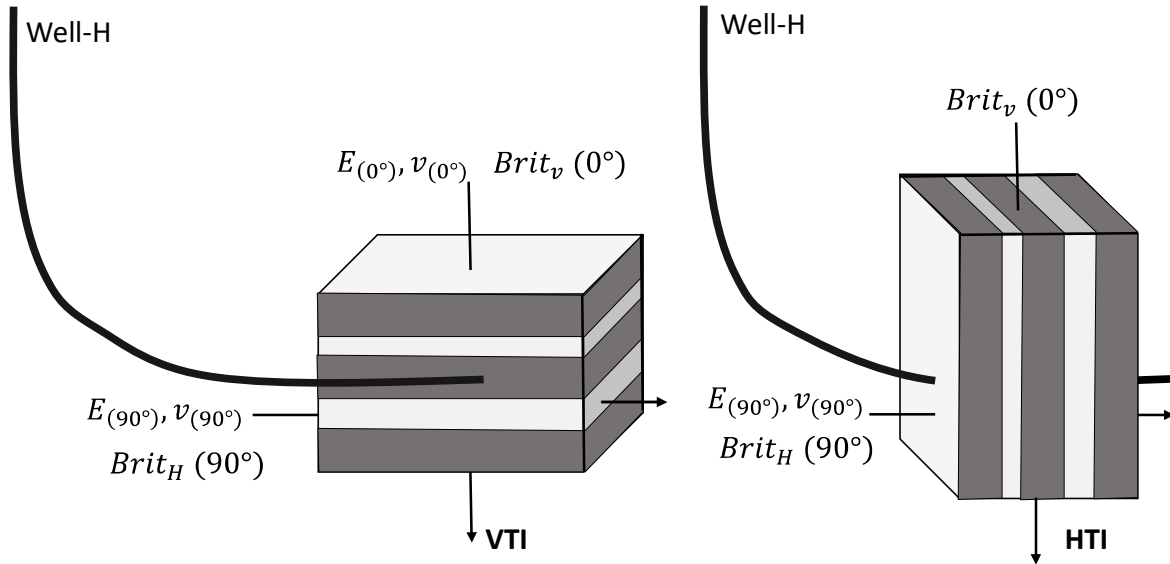


Figure 5.67. Scheme of brittleness calculation ($Brit_v (0^\circ)$) is in the symmetry axis equal to 0° and ($Brit_H (90^\circ)$) is in the symmetry axis equal to 90° .

In unconventional reservoirs brittleness is a significant parameter for the definition of a shale sweetspot and is critical in the hydraulic fracture technology and the design of horizontal well trajectories (Jarvie, et al. 2007). There are several equations in the literature to estimate this property one of the most accurate is the laboratory measurements. However, to acquire measurements are expensive and limited in samples that is why the use of 3D seismic data or logging data are more likely alternative to be used for the calculation of brittleness (Goodway et al. 1999, 2010). This property cannot be measured directly from seismic or well log data (Li et al. 2012).

Two types of brittleness index are in the literature, the mineralogy-based method, and the elastic parameter-based method. Both methods are predictive and are widely used in the oil industry. The one preferred in this project is the elastic-parameter-based method using Young's modulus, Poisson's ratio, Lamé constants. This method seems to give better results for brittleness estimation because it contains information pertaining to both pore fluid and mineralogy. In contrast the prediction of brittleness based on mineral composition alone is still widely used since the parameters are easy to obtain directly from core, albeit at a high cost.

Young's modulus and Poisson's ratio, related to mineral, porosity, total organic carbon (TOC) content, and rock strength, are treated as an indicator of rock brittleness, which play significant roles in seismic reservoir characterization to evaluate hydraulic fracturing and infer sweet spots of unconventional reservoirs (Harris et al. 2011; Sena et al. 2011). Young's modulus and Poisson's ratio are usually estimated from surface seismic data indirectly with the computation of P- and S-wave velocities and density to perform the "sweet spot" discrimination and optimization of horizontal well placement (Sena et al. 2011). There are, however, two difficulties. Firstly, when computing the Young's modulus, the density needed is more problematic than the inversion of P-wave and S-wave velocities even with the seismic data containing the information of large incident angles or offsets (de Nicolao et al. 1993; Debski and Tarantola 1995; Downton 2005; Kabir et al. 2006). Secondly, the indirect computation of Young's modulus and Poisson's ratio accumulates errors and causes much more bias in parameter estimation (Zong et al. 2013a, b; Yin and Zhang 2014). In this paper, we demonstrate an approach of direct inversion for Young's modulus, Poisson's ratio, and density from surface seismic data to avoid the indirect estimation and accumulated errors.

The first process of azimuthal simultaneous inversion from partial angle-stack seismic data is generally implemented incorporating the seismic wavelets at different incident angles and azimuths convoluted with the normal-incidence reflection coefficient, in which the inversion algorithm used in this process is the same as that of post-stack seismic inversion (Russel and Hampson 1991). Here I implement the process of azimuthal simultaneous inversion for Young's modulus, Poisson's ratio, elastic parameters to use in Rickman equation in four azimuthal inversion.

5.4.3.1 Limitations of Brittleness Index

The Brittleness Index (BI) is a widely used tool in the oil and gas industry to characterize the mechanical properties of rocks in unconventional reservoirs. The index is defined as the ratio of Young's modulus (E) to the Poisson's ratio (ν), which is used to describe the elastic behavior of a material. The BI is an indicator of the rock's brittleness, which is an important factor in determining the production potential of unconventional reservoirs. However, despite its widespread use, the BI has several limitations that must be considered when interpreting its results.

One of the major limitations of the BI is that it does not account for the influence of pore pressure on the mechanical properties of rocks. In unconventional reservoirs, pore pressure is often high, which can result in a reduction of rock strength and an increase in rock deformability. This can lead to inaccurate results when using the BI to assess the brittleness of these rocks. For example, a rock with a low BI may be considered brittle, while in reality, it may be much more deformable due to high pore pressure. This can result in incorrect predictions of the production potential of a reservoir and can lead to significant economic losses.

Another limitation of the BI is that it does not account for the effects of stress anisotropy. In unconventional reservoirs, the stress state can be highly anisotropic, which can result in different mechanical behavior in different directions, and these can be difficult to capture using the BI. In these cases, more sophisticated techniques, such as multiaxial testing or numerical simulations, may be required to accurately characterize the mechanical properties of the rock. For example, for this thesis, The BI was computed in different directions based on the results of the seismic inversion in 4 azimuthal sectors (Chapter 6 section 6.2.3).

The BI is also subject to the usual measurement errors of the data used to calculate this parameter. In order to calculate the BI, accurate measurements of both Young's modulus and Poisson's ratio are required. However, obtaining these measurements can be challenging in unconventional reservoirs, particularly in the case of low permeability rocks. In these cases, the measurement of mechanical properties can be influenced by the presence of fluid and by the rock's microstructure, making it difficult to obtain accurate results.

Finally, the BI is limited by its simplicity. The BI is a single parameter that is used to describe the mechanical properties of rocks, and it does not account for the complex interactions between the various rock properties that can impact the production potential of an unconventional reservoir. For example, it does not account for the effects of rock grain size, mineralogy, or fluid saturation on the mechanical properties of the rock. To overcome these limitations, more comprehensive and sophisticated techniques, such as rock physics models, may be required.

In conclusion, the Brittleness Index is a widely used tool in the oil and gas industry to characterize the mechanical properties of rocks in unconventional reservoirs. However, it has several limitations that must be considered when interpreting its results. These limitations include its lack of consideration for the influence of pore pressure, stress anisotropy, data accuracy, and its simplicity. Therefore, it is important to consider these limitations and to use additional techniques when necessary to accurately assess the production potential of unconventional reservoirs.

5.4.3.2 Anisotropic brittleness concept using azimuthal Inversion

Anisotropy refers to the property of a material that exhibits different physical and mechanical characteristics in different directions. This concept is of particular importance in the field of rock physics, where it is used to describe the behavior of rocks under stress and strain. Anisotropy in rock can be attributed to a number of factors, including mineral orientation, layering, and pore orientation. One important manifestation of anisotropy in rock is anisotropic brittleness. This term refers to the observation that rocks can exhibit different levels of brittleness depending on the direction of loading. For example, a rock may be relatively brittle in one direction, but more ductile in another.

The degree of anisotropic brittleness in a rock is dependent on a number of factors, including mineral composition, texture, and structure. For example, rocks that contain minerals that have a preferred orientation, such as shale, tend to be more anisotropically brittle than rocks with random mineral orientation, such as sandstone. Additionally, the presence of layering or bedding can also contribute to anisotropic brittleness, as the layers may have different mechanical properties and respond differently to stress.

The study of anisotropic brittleness in rock physics has important implications for a number of fields, including geology, mining. For example, a better understanding of the brittleness of rocks can help geologists to predict potential failure mechanisms that may have impact in the wellbore design for fracking technology.

Anisotropic brittleness is an important concept in the field of anisotropic seismic inversion, as it can affect the seismic wave propagation and, therefore, impact the results of seismic data analysis. Anisotropic seismic inversion refers to the process of inferring the subsurface velocity structure of a rock mass from seismic data, considering the anisotropic nature of the rock (Chapter 6, section 6.2.3). The anisotropic brittleness of rocks can cause variations in seismic wave velocities and amplitudes, which can result in distorted images of the subsurface structure. This can impact the accuracy of the inversion results and lead to misinterpretation of the subsurface properties. For example, anisotropic

brittleness can cause differences in the wave velocities in different directions, which can lead to errors in the estimated subsurface velocity structure.

To account for the effects of anisotropic brittleness in seismic inversion, it is necessary to consider the anisotropy of the rock. This can be done by using anisotropic seismic inversion volumes addressed in Chapter 6 and incorporating anisotropic parameters, such as the Thomsen parameters, into the inversion process used to describe the degree of anisotropy in terms of the relative wave velocities and attenuation in different directions as shown in chapter 6 where the seismic was divided into several sectors ordered by azimuth and angle of incidence to obtain P-S impedances in four main directions.

In conclusion, the concept of anisotropic brittleness is important in the field of anisotropic seismic inversion, as it can impact the seismic wave propagation and, therefore, the accuracy of the inversion results. To account for the effects of anisotropic brittleness, it is necessary to consider the anisotropy of the rock mass and incorporate anisotropic parameters into the inversion process. This can lead to more accurate images of the subsurface velocity structure and a better understanding of the subsurface properties.

5.4.4 Differential effective medium (DEM)

One interesting point made in this thesis is the impact of the volume fraction of kerogen on the seismic properties of shale due to its low density. This highlights the importance of accurately modeling the complex composition of porous rocks like shale to accurately predict their elastic properties and seismic response.

The use of DEM theory and Li and Zhang's formula for analyzing scatter data in the Pimienta Formation. By comparing the results to experimental data, better understanding of the relationship between bulk modulus and porosity in this formation is gain, as well as the potential impact of factors such as pore shape and aspect ratio.

5.4.5 Effective field method (EFM)

The EFM has been used in the estimation of elastic wave propagation velocities in cracked rocks. The method has been employed to model the crack density for sub-vertical fractures and their orientation angles using data from DSI cross-dipole measurements from well-log at Anhelido-1 within the Tamaulipas and Pimienta Formation. The EFM produces explicit equations for the effective characteristics for composites with ellipsoidal inclusions.

The resulting velocities measured and calculated V_{sv} and V_{SH} have an excellent correlation using (EFM) showing differences in V_{fast} and V_{slow} modes suggesting the anisotropy within the Tamaulipas and Pimienta formation, in this case, Tamaulipas formation has higher degree of anisotropy based on the difference in the slow and fast velocities.

5.5. Conclusion

The analysis leads to the following conclusions:

1. The application of AVAz allowed the estimation of both fracture density and fracture orientation within the Pimienta Formation.
2. The combination of different data source (e.g., Microseismic, Structural Attributes, AVAz and FMI log data) provide an insight to better understand the anisotropy within the Pimienta Formation.
3. Fracture modelling in effective medium comparison with AVAz performed in Hampson and Russell software confirm similar response with the models addressed in Chapter 4 (sections 4.3.1, 4.3.2, 4.3.3) (e.g., Hudson, and Linear-slip).
4. Microseismic data, structural attributes (e.g., Edge detection and Edge enhancement), and AVAz (V_{fast} polarization vector planes) exhibit a preferential orientation of (macro fractures)

and possible groups of fractures detected by AVAZ NE which have a relative agreement with the natural fractures from FMI information and caliper log data.

5. An approach for the estimation of brittleness in two different modes 0° and 90° has been developed in this Chapter and applied for the first time within the Pimienta Formation in the north of Mexico and can be widely applied for other shale rock groups.
6. The concept of Differential Effective Medium theory (DEM) and a formula developed by Li and Zhang (2010) for analyzing the relationship between bulk modulus and porosity in scatter data analysis within the Pimienta Formation has been analyzed in this thesis.
7. Importantly, I found that the Pimienta Formation in the rock physics templates displayed in RokDoc software better fit with the Friable-Sand Model instead of the Friable-Shale Model of Dvorkin & Nur (1996). This may be considered a promising aspect of the behaviour of this Formation as this is a shale rock suggesting that we still have a long way to go to better understand the shale rock mineral composition in a rock physics template.
8. In this chapter insights into the complex problem of estimating the effective physical qualities of heterogeneous random media and highlights the importance of employing self-consistent schemes to solve the homogenization problem has been addressed using the Effective Field Method (EFM) to estimate elastic properties within Tamaulipas and Pimienta formations.

6. A novel approach to estimate TOC/Brittleness and stress field using seismic inversion based on azimuthal data

6.1 Introduction

Total organic carbon (TOC) and brittleness are two important parameters used in the oil industry to characterise the quality of sweet-spots and define the best locations for hydraulic fracturing (Caeiro, M. H., Al Kobaisi, A., & Neves, F. (2017)). TOC is the amount of organic carbon present in the source rock and is important to quantify in order to build petroleum systems models for conventional exploration (e.g., Wang, 2017; Selley, 2005). The TOC distribution in stratigraphic successions is also important as a constraint in paleoclimate studies (Jenkyns, 2010).

TOC and Brittleness are readily measured using well information (Passey et al., 1990; Rickman et.al., 2008), although the areal coverage this provides is limited to the sampling positions of the wells, and interpolation between wells is then required, with its inherent uncertainty. This may be sufficient for conventional exploration, where the gross distribution of source rocks is the objective but is insufficient as an input into unconventional exploration where sweet spot identification is key, often at spatial scales that are aliased by the well distribution. For this reason, several techniques have been developed to estimate the lateral variation of these two parameters. Amongst others, seismic inversion provides a good geophysical tool to complete this task, particularly for TOC.

Seismic inversion is an essential tool in reservoir characterization that enables well and seismic information to be combined to predict lithology and fluid content far from the well position. The main objective of this technique is to transform reflectivity into quantitative information of rocks that allow the description of the formation in terms of elastic properties (Bosch et. al, 2017). The inversion can be performed using stacked angle volumes or using the seismic pre-stacked gathers directly, which allow the estimation of P impedance, S impedance and density (Russell et. al, 2006).

In a shale formation, any anisotropy affects most of the elastic properties of rocks and renders the seismic inversion result less reliable (Bayuk et al. 2007, Ortega et al. 2009). Azimuthal seismic data can be used to perform an anisotropic inversion (Chen et. al, 2018). Anisotropic inversion using

azimuthal seismic data, however, has not previously been used to estimate the variation of TOC and Brittleness in an unconventional shale formation target in different azimuths. This gap in techniques has hitherto precluded the prospect of properly defining sweet spots where high spatial resolution of these two key parameters is required (Tobi M.O. 2020).

6.1.1 Aims

In order to characterize the parameters of TOC and brittleness through azimuthal seismic inversion, the main aim is to use equations 5.22, 5.23, and 6.17 by adding an extra dimension in both properties for example the TOC in four azimuth sectors of the seismic gathers (ϕ) and the Brittleness Index $BI(0^\circ)/BI(90^\circ)$ in four azimuth sectors of the seismic gathers (ϕ). The azimuthal inversion with these two parameters previously described (TOC/Brittleness) will be tested in a chapter specific study area of 9.2 Km² around Anhelido-1 and Anhelido-1H (Figure 6.1).

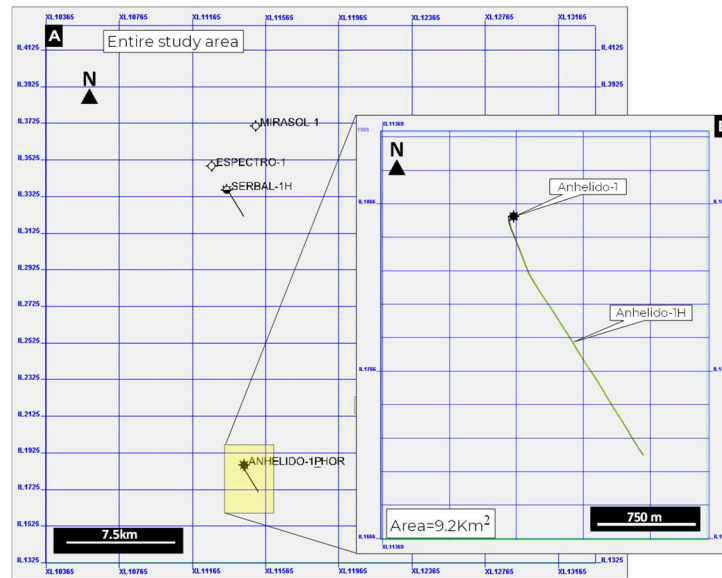


Figure 6.1 (A) Entire study area; (B) Selected area 9.2 Km² around Anhelido-1 and Anhelido-1H for the azimuthal seismic inversion.

6.1.2 Phase of a seismic wavelet (seismic inversion)

The seismic wavelet is the important link between seismic data and stratigraphy as well as rock properties of the subsurface. Seismic wavelet estimation is done to deconvolve the seismic trace, tie the well log to the seismic data, and design inversion operators.

In the stationary case, the seismic trace $s(t)$ can be modeled by the convolution of the seismic wavelet $w(t)$ and the reflectivity $r(t)$ plus noise $n(t)$ (Sheriff and Geldart, 1995)

$$s(t) = w(t) * r(t) + n(t)$$

Here we ignore all the other physical effects of wave propagation such as wavefront spreading, transmission loss, multiples, attenuation, and anything else conceivable. Noise $n(t)$ is assumed to be white and stationary.

Two kinds of idealized wavelets are most common in geophysics. One is the minimum phase wavelet, which models the recorded seismic wavelet. It has no energy before time zero and has most of its energy concentrated at the front. The other is the constant-phase wavelet, which models the residual wavelet after deconvolution. It has energy before time zero and has a constant-phase across dominant frequencies. Among constant-phase wavelets, the zero-phase wavelet, which is symmetrical about time zero, is the best for interpretation (Simm and Bacon, 2014). Figure 6.2 shows a minimum-phase wavelet and a 100-degree phase wavelet in both time and frequency domains. The statistical wavelet method estimates the wavelet from the seismic data alone. Take the seismic trace $s(t)$ and calculate its autocorrelation so no well data is considered in this method.

Perhaps the most common type of wavelet used for seismic data is the zero-phase wavelet. When compared to minimum phase wavelets, these zero phase wavelets are symmetrical and are very broad band in the frequency domain. That being the case, an investigation into the changes that may occur when a zero-phase wavelet is used in the reflectivity analysis is done.

The full wavelet method uses both the seismic and reflectivity to determine the amplitude and phase spectra of the wavelet by applying a least-square filter which shapes the reflectivity to the seismic. An exact wavelet can be extracted without assumption about its amplitude or phase. However, this method is very sensitive to the quality of seismic-to-well ties (Hampson-Russell Software, 2013).

Wavelets are transient waveforms with a finite duration. They can be minimum, maximum, or mixed phase. A minimum phase wavelet has most of its energy at the onset of the time series, while a maximum phase wavelet has most of its energy at the end of the time series. Mixed phase wavelets have their energy distributed throughout the time series. In addition, a wavelet is realizable if it is finite in length (i.e., a finite time series) and is causal if it is zero for all negative times. Hence, a minimum phase wavelet is one that is minimum phase, realizable, and causal. These kinds of wavelets have the least energy delay. Mathematically, a stable inverse means that the filter coefficients make a convergent series. That is, they decrease with increasing time and vanish at infinity. This means that a stable inverse filter has finite energy. Minimum phase wavelets have stable inverses, but maximum and mixed phase wavelets do not.

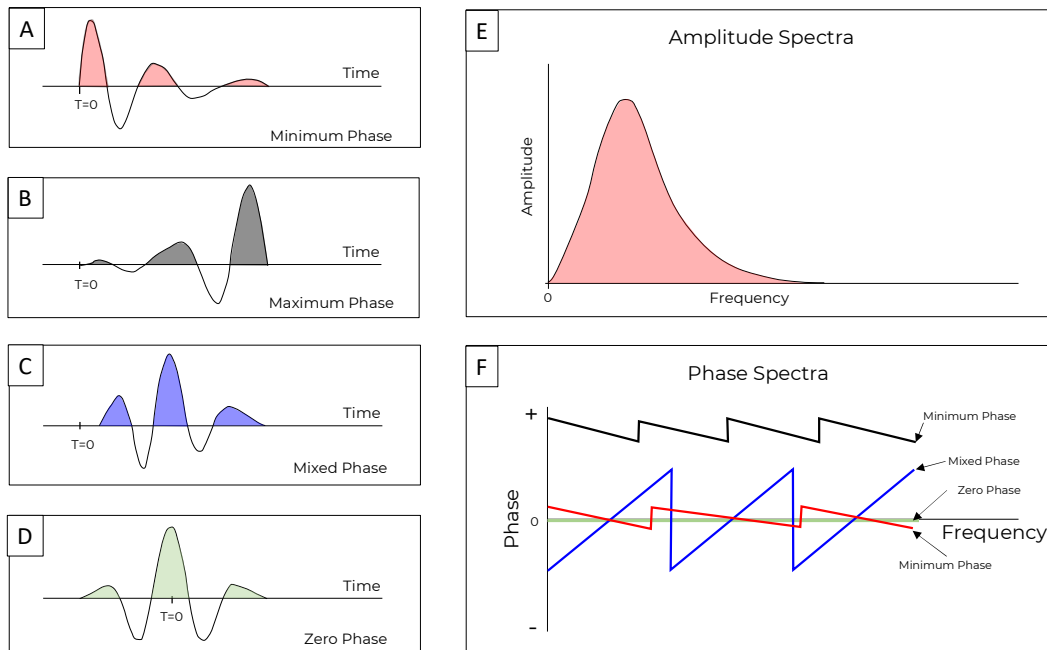


Figure 6.2 Phase wavelet examples and amplitude spectra.

Wavelet estimation process

Wavelet estimation lies at the heart of any seismic inversion project. The inferred shape of the seismic wavelet will strongly influence the assessment of the reservoir quality. I used Hampson and Russell software to generate an estimated wavelet. This exercise will go through the model driven wavelet estimation process (known as the Roy White estimation), which is the most common wavelet estimation technique for reservoir characterization.

The Roy White methodology (White, 1980) allows us to quantify how good a well tie is, and hence, demonstrate improvement after log editing or seismic conditioning. It allows us to analyze error bars on the seismic wavelet spectrum so we can see whether the wavelet is well determined.

The Roy White method is essentially a coherence matching technique. The workflow can be summarized as follows:

1. From well log data we estimate the earth reflectivity.
2. A volume of seismic data around the well is scanned for the best statistical fit to the synthetic trace, and a wavelet is estimated at that trace.
3. The filter providing the best match between the earth reflectivity and the seismic is our best estimate of the original seismic wavelet.

In an inversion, we are attempting to remove this wavelet from the seismic, so clearly, it's vital to know what it looks like. Figure 6.3 shows the schematized Roy White methodology and Figure 6.4 the wavelets used in this project.

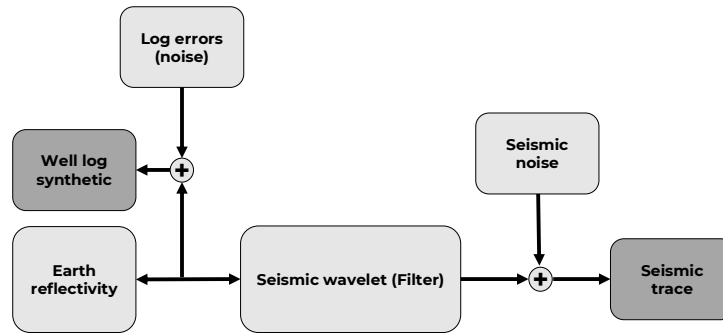


Figure.6.3 The Roy White methodology.

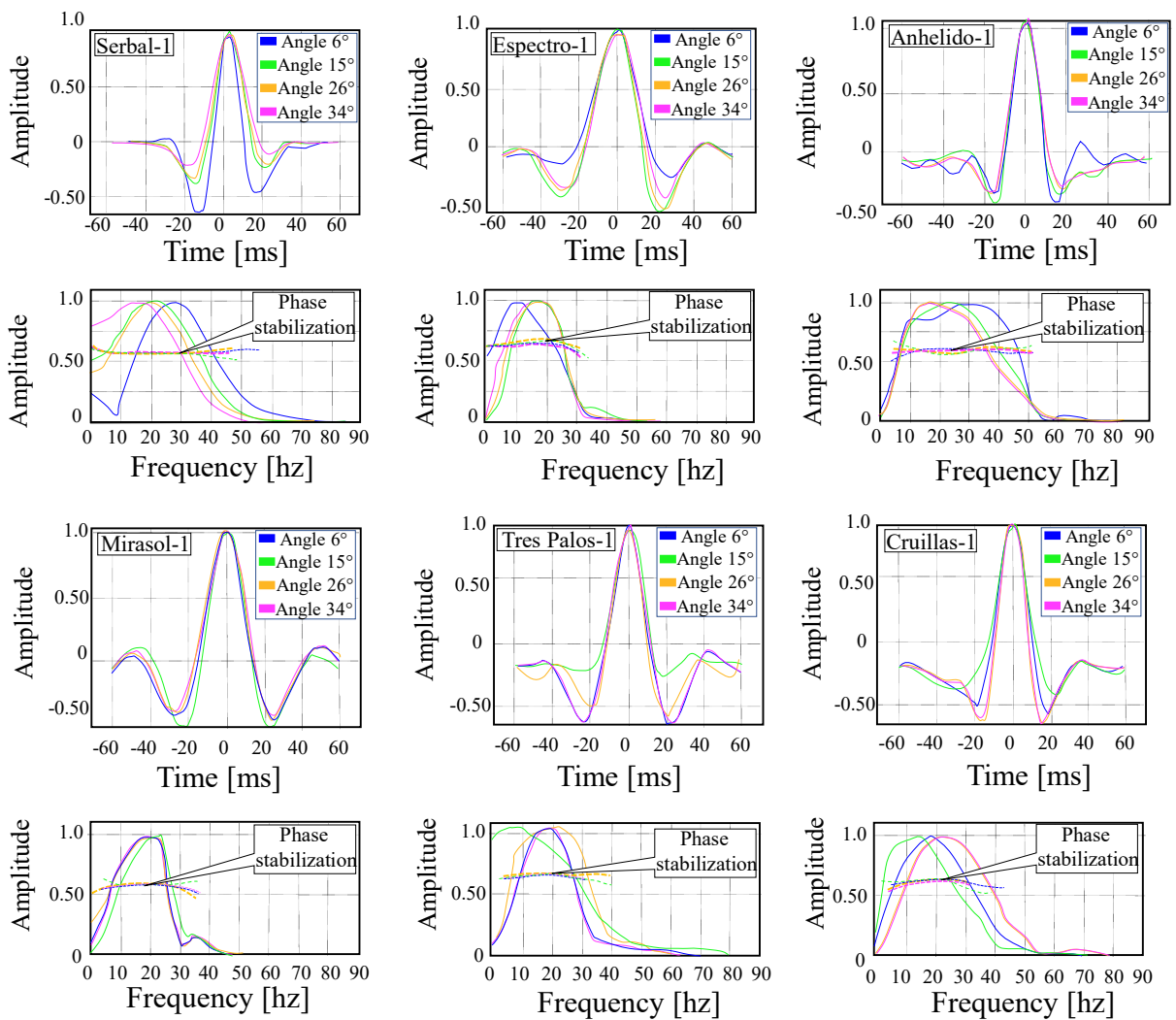


Figure 6.4. Wavelets time response used in the project using Roy White approach near zero wavelet for the inversion process (6 wells in total in the study area); then in Anhelido-1 more wavelets estimation will be calculated in for azimuthal sectors in this chapter (Figure 6.7).

When estimating a wavelet, the chosen method depends on the data availability. If there is well data available, a wavelet can be estimated with the model-driven technique in estimate wavelet amplitude and phase spectra. The algorithm uses the well log data and the seismic to find the wavelet that produces the best synthetic match to the seismic data. Use of multiple wells and multiple traces per well reduces the likelihood that noise in the seismic will be incorporated into the wavelet.

Roy White defined two important concepts useful to quantify the quality of a well tie: the goodness of fit, and the wavelet accuracy. Maximizing these two measures should deliver the best wavelet, with the smallest error bars.

The goodness of fit measurement is called PEP, the proportion of energy predicted from the synthetic. Numerically, it's approximately the square of the cross-correlation, and a value greater than 0.7 is considered good.

Goodness of fit is not a measure of the accuracy of the wavelet. The cross-correlation increases with increase in wavelet length, but the longer the wavelet is, the more chance that noise is also being matched.

If a value of one is achieved, it implies a perfect match between the seismic and the synthetic, using the estimated wavelet (i.e., the residual is zero).

The goodness of fit is defined by equation [1]:

$$PEP = 1 - (energy\ in\ \frac{residuals}{trace\ energy})$$

The maximum PEP value is not necessarily found at the well location or along a composite trace along the well trajectory. In practice, a seismic cube is scanned around the well location in order to find a maximum PEP. This approach is preferable since positioning of seismic energy during migration carries uncertainty, well positioning itself may be uncertain, and lateral stability of the estimation may be better understood with PEP maps.

The wavelet accuracy is given by NMSE, the normal mean squared error, that is calculated using equation [2]:

$$NMSE = \frac{0.59L}{T} * \frac{1 - PEP}{PEP}$$

Where L is the wavelet length and T is the length of the time window from which the wavelet is estimated. A good well tie has NMSE less than 0.2.

The window T we choose is a function of the frequency content of the seismic or the bandwidth. The higher the bandwidth, the smaller the time window.

The wavelet length is then simply calculated from the time window. Usually, L is a value between a 1/3 and a 1/7 of the time windows used.

The relationship between the Goodness of Fit and Wavelet Estimation error as a function of the ratio $\frac{\text{Wavelet Length}(L)}{\text{Time Window}(T)}$ can be seen in Figure 6.5.

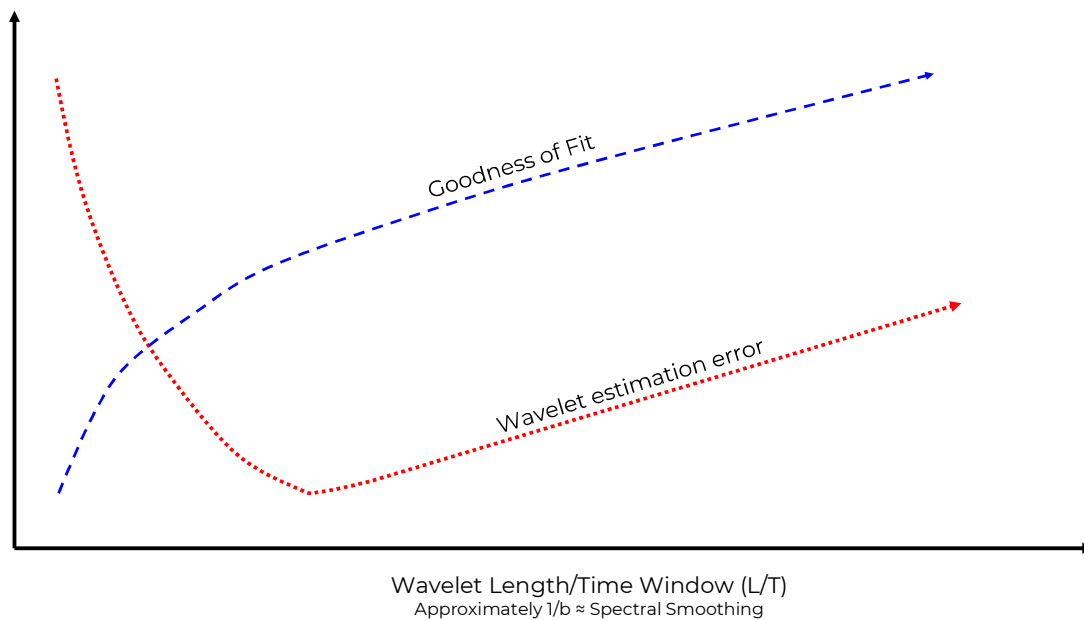


Figure 6.5. Goodness of Fit and Wavelet Estimation Error vs. L/T ratio. As the (L/T) ratio goes up, or the wavelet length to window length goes up, the goodness of fit, or PEP always increases.

The longer the ratio L/T is, the better it can fit everything in the time window. But as the wavelet gets longer, the wavelet begins to also fit noise, and the wavelet estimation error goes up. At the opposite end of the axis, the goodness of fit is poor, as we are over-smoothing in the spectral domain. The idea is to find the optimum zone, where the error is low and the goodness of fit is high.

Without well control, the wavelet estimation is based on statistical techniques. This process is done in two steps: estimation of the wavelet amplitude spectrum, followed by the estimation of its phase spectrum. When estimating the amplitude spectrum without wells, the basic inputs are the seismic traces and a time gate. The estimate wavelet amplitude spectrum option produces a zero-phase wavelet. The phase of the seismic wavelet can be estimated with the estimate wavelet constant phase spectrum option. In this case, the operator assumes a constant wavelet phase and models the data using a range of phase rotations. The correct phase shift is assumed to be that which produces the spikiest model. Knowledge of the wavelet polarity is necessary, however, since this algorithm is insensitive to polarity.

Some projects can benefit from the use of the two methodologies together. One example of this is in areas where the well control is only available shallower than the zone of interest. In this case, a shallow wavelet can be estimated using the model-driven technique in estimate wavelet amplitude and phase spectra. The amplitude spectrum of the deeper zone of interest can be derived using an estimated wavelet amplitude spectrum. With merged wavelet amplitude and phase spectra the deeper amplitude spectrum is then merged with the shallower phase spectrum to create a composite wavelet. Another example of where combining the techniques can be beneficial is when the model-driven technique cannot adequately capture the seismic amplitude spectrum. In such case, a wavelet with the amplitude spectrum of the seismic data, derived with estimate wavelet amplitude spectrum, can be used as an *a priori* wavelet to influence the results of the model-based estimate wavelet amplitude and phase spectra.

In the case when positioning problems with the well or the seismic data are suspected, the estimated wavelet amplitude spectrum and estimated wavelet constant phase spectrum can be used with the well at the initial position. This wavelet can then be used with the well to find the optimum location for wavelet estimation using the end optimal well position (vertically and laterally) option in wavelets. Once an improved location is found, the model-driven technique in estimate wavelet amplitude and phase spectra can be used to obtain an improved wavelet.

When using the model-driven wavelet estimation scheme, it is recommended that wavelets modules are used to find the best wavelet and well tie. The wavelet is applied and the synthetic to seismic comparison can be used to judge the quality of the wavelet. Moreover, adjustments to the well logs can be made and immediately saved for use in wavelets. In turn, in wavelets, the edited wells are used to improve the estimate of the wavelet. Here is the suggested workflow:

Within the wavelets module I created a synthetic wavelet to obtain an initial wavelet used to start the process of tying the well. Then I created and edit the time/depth relationship by bulk shifting and stretch/squeezing as necessary. When an initial tie is performed, the well is saved as first version.

Following this, I return to the embedded wavelets and calculate a new wavelet using the estimate wavelet amplitude and phase spectra option. The process of editing the time/depth relationship and estimating a new wavelet is repeated as necessary until a satisfactory wavelet and well tie is obtained.

6.2 Data and methods

The seismic data set used in this part of the project is a sub-volume of the entire area shown in Figure 6.1. The azimuthal seismic gathers were conditioned and subdivided in different azimuthal sectors (e.g., sector 1 (0° - 90°), sector 2 (90° - 180°), sector 3 (180° - 270°), sector 4 (270° - 360°)) (Table 6.1). the seismic processing is addressed in section 3.2.1 and Figure 3.6.

Data set	Near-angle stack	Mid-angle stack	Far-angle stack	Ultra-far-angle stack
Sector 1	(0°-90°)	(0°-90°)	(0°-90°)	(0°-90°)
Sector 2	(90°-180°)	(90°-180°)	(90°-180°)	(90°-180°)
Sector 3	(180°-270°)	(180°-270°)	(180°-270°)	(180°-270°)
Sector 4	(270°-360°)	(270°-360°)	(270°-360°)	(270°-360°)

Table 6.1 Dataset subdivided in four azimuth sectors and the incidence angle for each sector. (e.g., near, mid, far, and Ultra-Far)).

Anhelido-1 and Anhelido1H were the wells used in this Chapter. These wells drilled through the Pimienta Formation over a depth range of 2040-2170 m (vertical pilot well) then a horizontal well was drilled targeting the Pimienta Formation horizontally with a trajectory over a range of depth (2422m–3857m) in measured depth (Figure 6.6). The horizontal well was subjected to several geophysical measurements and cores were cut at specific intervals for further petrophysical and lithological analysis.

The data provided by Pemex comprise borehole logs, check-shot, and data from the hydraulic treatments (stimulation and pressure history) in the horizontal trajectory of the wellbore. The dataset also includes triaxial test data (Anhelido-1) which were used to calculate the static Young's Modulus. This information will be addressed as part of the brittleness estimation in section 6.2.3 of this Chapter.

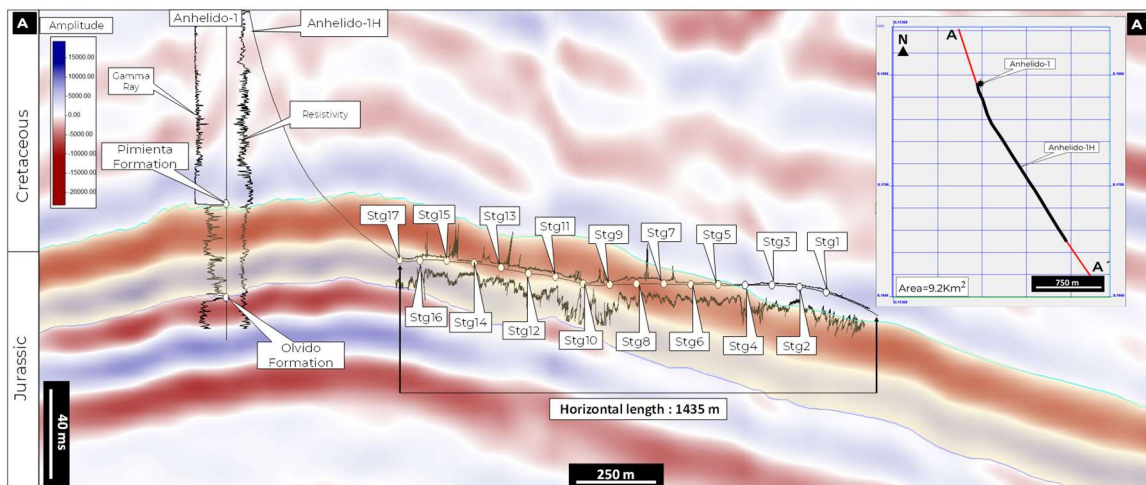


Figure 6.6. Arbitrary line along trajectory of well Anhelido-1H and vertical well Anhelido-1 displaying Gamma-ray and Resistivity logs with a total length in horizontal side of 1435m; A total of 17 treatment stages set in the horizontal section.

The TOC estimation previously documented in Chapter 3 (see Chapter 3.2) was used as an input to calculate the volume of upscaled TOC through seismic inverted data for each azimuth sector.

The well logs of Young's Modulus and Poisson's Ratio (Vertical (0°)/Horizontal (90°)) calculated in section 5.2.4.2 Chapter 5 are used in this chapter to estimate the same elastic parameter in the azimuthal inversion for the four sectors mentioned in Table 6.1.

Each azimuth sector was subdivided into four partial angles which were then stacked (e.g., Near, Mid, Far, and UltraFar) (Figure 6.7)

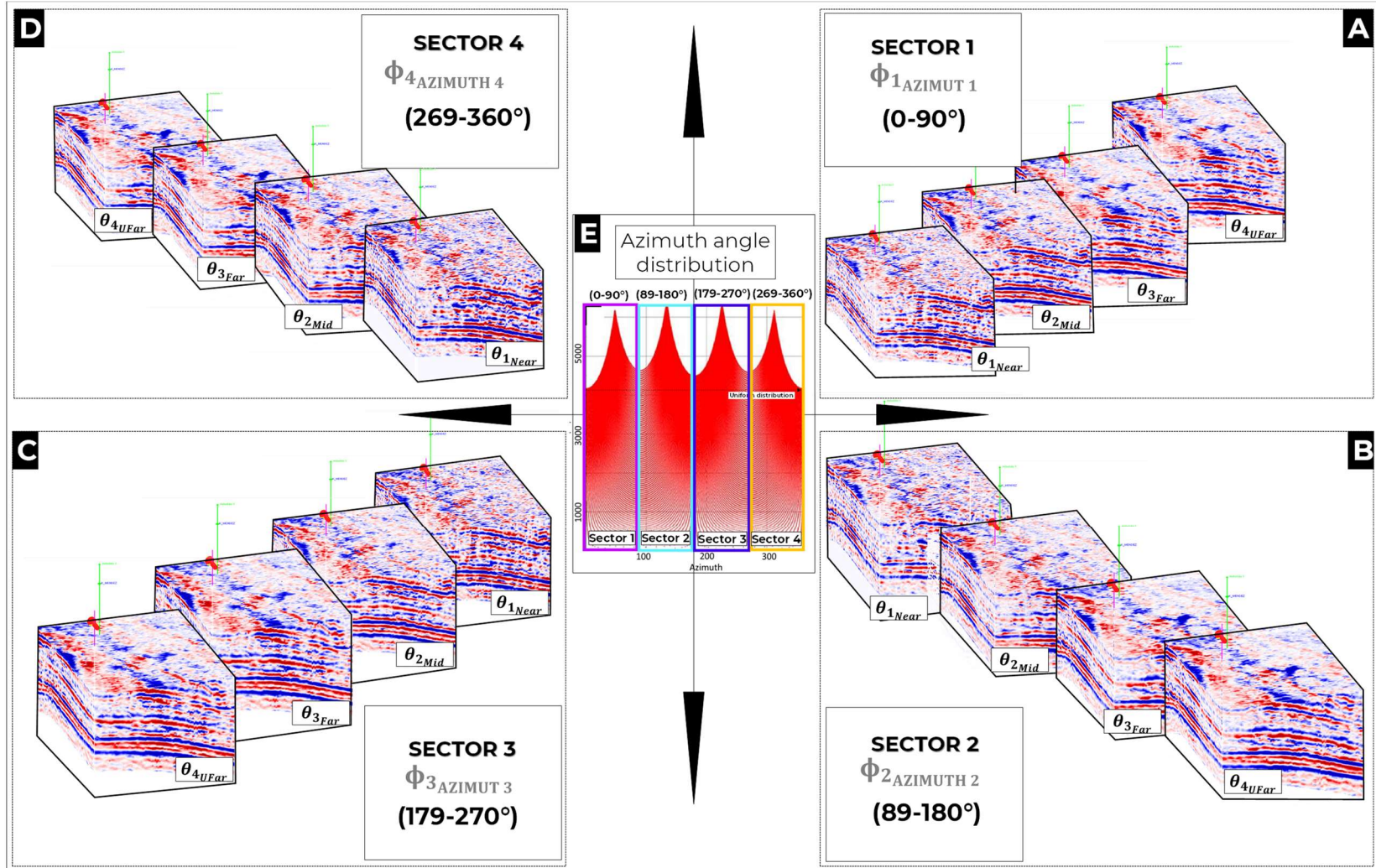


Figure 6.7. (A) Azimuthal sector 1 (0° - 90°) and four angle stacked volumes (Near, Mid, Far, and Ufar); (B) Azimuthal sector 2 (89° - 180°) and four angle stacked volumes (Near, Mid, Far, and Ufar); (C) Azimuthal sector 3 (179° - 270°) and four angle stacked volumes (Near, Mid, Far, and Ufar); (D) Azimuthal sector 4 (269° - 360°) and four angle stacked volumes (Near, Mid, Far, and Ufar); (E) Azimuth angle distribution of the seismic gathers; These volumes correspond to a small area around the horizontal wellbore Anhelido-1H including Anhelido-1.

The data listed above has been manipulated and used following standard and advanced geophysical techniques. These comprise seismic inversion, anisotropic upscaled TOC based on inverted Impedances, anisotropic Young's modulus/Poisson's Ratio, and anisotropic brittleness.

In order to correctly invert seismic data, estimation of the initial wavelet needs to be made. The wavelet estimation was performed using procedures outlined by White, (1997). This was necessary to improve the shape of the reflection coefficient of the P-impedance of the well log for the selection of traces in the input seismic volumes used for the inversion. The phase of the wavelet is known to vary with frequency (Levy and Oldenburg, 1987; Arons and Yennie, 1950; Van der Baan, 2008).

Hence the workflow to estimate the wavelet fundamentally begins with the establishment of the optimal time-depth relation in the well, by comparing the synthetic seismic traces with the real seismic of the project at the well location. The following step is to produce the optimal wavelet for each azimuth individually using the sub angle stack volumes presented in Figure 6.7. These processes were performed using the Hampson&Russell software package.

Seismic inversion was carried out after the wavelet estimation and to perform this operation, the seismic data were deconvolved using a wavelet extracted from the seismic data at the well location. Then an initial low-frequency model was applied to invert the seismic information. Because the inversion is anisotropic this operation was performed in four individual azimuth stacks sectors [0-90°, 90-180°, 180-270°, and 270-360°]. An independent wavelet was used for each stack angle and azimuth and used in the inversion algorithm (Figure 6.8).

Each wavelet was specially calibrated for its specific seismic volume, in terms of amplitude, frequency, and phase. In this way, each of the seismic volumes of partial angles was directly calibrated with the well-logs, and the final inversion volumes of properties of the rocks were normalized to find a solution to the real earth model. The resulting data were then converted from acoustic amplitude to acoustic impedance shown in the result section of this chapter (Figure 6.19).

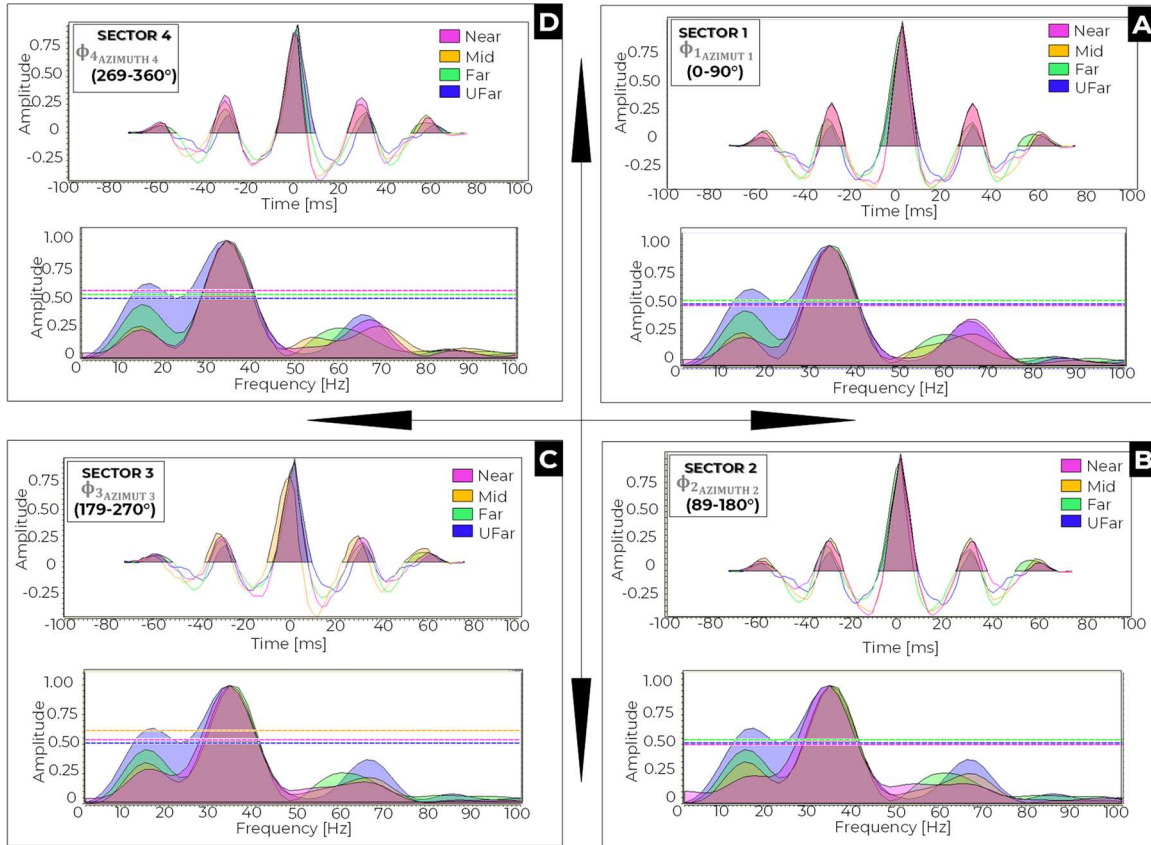


Figure 6.8. Wavelets (Near, Mid, Far, and Ultrafar) for every sector within reservoir zone (Pimienta Formation); A) Wavelets at Sector1 (0°-90°); B) Wavelets at Sector2 (90°-180°); C) Wavelets at Sector3 (180°-270°); D) Wavelets at Sector4 (270°-360°).

6.2.1 TOC

In Chapter 3, I calculated the TOC log through application of Passey's method using the resistivity and density logs. The TOC values were presented in section 3.4 of Chapter 3. This data was taken as a starting point to be used in the seismic inversion data for each azimuthal sector to estimate the TOC as a function of the Impedances, for this purpose I applied the Vernik equation (2002) to which I modified by adding an extra variable (see Section 6.2.3.).

6.2.2 Static Young's Modulus

The determination of the anisotropic Young's Modulus is an essential component to estimate the brittleness of rocks. Stress-strain curves were plotted from the triaxial test data to determine the value of Young's Modulus. Figure 6.8 shows the relative stiffness, strength, and brittleness I derived from the stress-strain relationship as a standard method in rock mechanics.

The triaxial test data were provided by PEMEX and performed by Weatherford applying different confining pressures at different depths within the Pimienta Formation. This was used to model the in-situ stress conditions with a total of 5 samples provided. This study was designed to obtain the static values of the Young's Modulus.

There are two standard methods to estimate Young's Modulus (Małkowski, Piotr & Ostrowski, Łukasz & Brodny, Jarosław. (2018)). The first uses the tangent of Young's Modulus, E_T , which is the slope of the axial stress-strain curve, usually at 50% of the peak strength. The second is based on the secant Young's Modulus, E_S , as the slope joining the origin of the axial stress-strain curve to a value on the curve at some fixed percentage of peak strength (Figure 6.9).

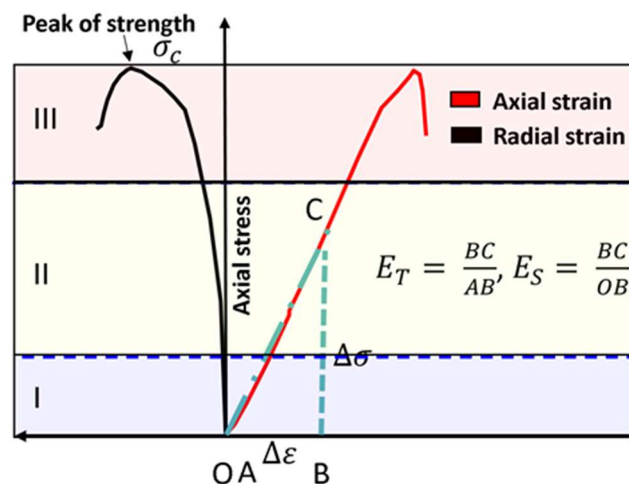


Figure 6.9. Static Young's Modulus from uniaxial stress-strain profile REF PEMEX E&P (modified from Keaton, 2018. The static Young's Modulus is measured from the slope of the loading line in the stress-strain region II highlighted in light yellow.

6.2.3 Anisotropic brittleness (0° and 90°) in four different azimuths

In order to calculate the brittleness, it was necessary to undertake a number of intermediate computational steps, including the estimation of the vertical (0°) and horizontal (90°) normalized Poisson's ratio e.q. (6.4, 6.5) and the vertical (0°) and horizontal (90°) normalized Young's Modulus e.q. (6.8, 6.9). The target interval within the reservoir zone of the Pimienta Formation is about 80 m thick and the measurements were applied to this interval using the Thomsen parameters using the Ryan-Grigor approach using the well log data within Pimienta Formation which are as follows:

- $\varepsilon = 0.12$
- $\gamma = 0.14$
- $\delta = -0.02$

$$g = \left(\frac{V_s}{V_p} \right)^2 \quad (6.1)$$

$v = GP_{PR}$ Geomechanical volume of Poisson's Ratio from inversion per azimuthal sector in Hampson & Russell software.

V_p, V_s – From inverted volumes per azimuthal sector

Vertical Poisson's Ratio (0°)

$$v_{(0^\circ)} = v \left[1 + \left(\frac{\delta}{1 - 2g} \right) + \left(2 \left(\frac{\varepsilon - g^2 \gamma}{1 - g^2} \right) \right) \right] \quad (6.2)$$

Horizontal Poisson's Ratio (90°)

$$v_{(90^\circ)} = v \left[1 + \left(\frac{\varepsilon}{2g^2(1 - 2g^2)(1 - g^2)} \right) - \left(\frac{2\gamma}{1 - 2g^2} \right) - \left(\frac{\delta}{1 - g} \right) \right] \quad (6.3)$$

The normalized Poisson's Ratio (0°)

$$v_{(0^\circ)Normalized} = \left[\left(\frac{v_{(0^\circ)max} - v_{(0^\circ)}}{v_{(0^\circ)max} - v_{(0^\circ)min}} \right) \right] \quad (6.4)$$

The normalized Poisson's Ratio (90°)

$$v_{(90^\circ)Normalized} = \left[\left(\frac{v_{(90^\circ)max} - v_{(90^\circ)}}{v_{(90^\circ)max} - v_{(90^\circ)min}} \right) \right] \quad (6.5)$$

For the Young's modulus, I used the same values of Thomsen parameters and the background velocity g . I took the average Young's Modulus volume estimated in each azimuth sector using the seismic inversion volumes and the typical Poisson's ratio performed in STRATA of Hampson & Russell package.

Which gives the next equations by Luan et.al., (2014) in terms of Thomsen's parameters and elastic properties:

Vertical Young's Modulus:

$$E_{(0^\circ)} = E - (4v\gamma) + ((4v^2)(\varepsilon - g\gamma)) \quad (6.6)$$

Horizontal Young's Modulus:

$$E_{(90^\circ)} = E \left[1 - \left(\frac{\varepsilon(1 - 2g)\gamma}{2g(3 - 4g)(1 - g)} \right) + \left(\frac{4(1 - 2g)\gamma}{(3 - 4g)} \right) \right] \quad (6.7)$$

Moreover, these values were normalized as follows:

Normalized vertical Young's Modulus:

$$E_{(0^\circ)Normalized} = \left[\left(\frac{E_{(0^\circ)} - E_{(0^\circ)min}}{E_{(0^\circ)max} - E_{(0^\circ)min}} \right) \right] \quad (6.8)$$

Normalized horizontal Young's Modulus

$$E_{(90^\circ)Normalized} = \left[\left(\frac{E_{(90^\circ)} - E_{(90^\circ)min}}{E_{(90^\circ)max} - E_{(90^\circ)min}} \right) \right] \quad (6.9)$$

And finally, the anisotropic brittleness following the formulation of Rickman et. al., 2008:

$$BI(\theta) = \left[\left(\frac{E(\theta)_{Normalized} + \nu(\theta)_{Normalized}}{2} \right) \right] \quad (6.10)$$

6.2.4 Stress field

Mechanical compaction is often considered paramount for the understanding of disequilibrium overpressures (Osborne and Swarbrick, 1998?). Overpressure prediction for fine-grained clastic sedimentary successions is typically made by basin modelling using standard relationships between effective stress and porosity (e.g. Goult, 1998). Claystones, mudstones, marls and shales typically have low permeability from initial deposition that restrict the rate at which fluid pressure can be dissipated under an increasing burial load of the overburden, meaning that effective stress is anomalously low and hence seismic velocities (Magara, 1978) are also anomalously low where the system is 'undercompacted.'. The classical relationship identified by Magara (1978) between overpressure and low seismic velocity only truly applies for fine grained clastic sediments where the porosity reduction is by mechanical compaction (consolidation) and not by chemical compaction (grain dissolution, reprecipitation and cementation) (Giles, 1997).

The velocity and density variation with depth obtained from wireline logs can provide useful constraints on the likely presence of overpressure in a basin fill, and moreover, what the possible

mechanism is for the occurrence of this overpressure (Flemmings, 2020). Different overpressure mechanisms that can be identified from the crossplot of Velocity vs Density are shown in Figure 6.10 and described in Table 6.2:

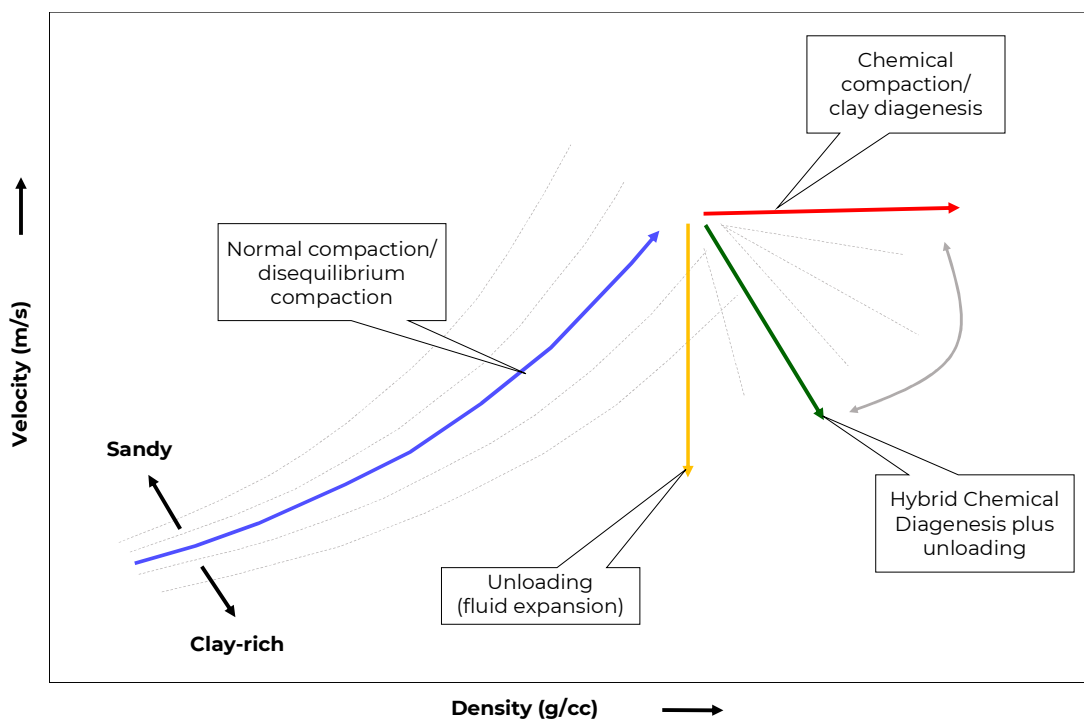


Figure 6.10. Mechanism of the overpressure for the Pore pressure estimation (after Hoesni 2004).

Mechanism	Description
Undercompaction	Velocity-Density remain on normal tren (increasing Velocity with increasing density).
Hydrocarbon-generation	Decreasing velocity with almost same density (unloading)
Diagenesis of clay	Constant Velocity with increment in density
The combination/ fluid expansion and clay diagenesis	Increment in density with decreasing velocity

Table 6.2 Mechanism of the overpressure and description.

6.2.4.1 Pore pressure in carbonate and shale rocks

Overpressure prediction is vital for unconventional hydrocarbon development to predict and adjust to wellbore drilling challenges related to the instability arising from anomalously high formation pressures such as blowout and kicks. Overpressure is an essential component in the producibility of shale gas, since it directly impacts flow into the fracture network.

Several empirical approaches have been developed among the subsurface geoscience community to elucidate and predict the overpressure where the mechanism is the primary consequence of undercompaction. These approaches have all been related to the effective stress sensitivity to the porosity (Fertl, 1976).

Most pore pressure methods make a comparison between a normal trend between velocity and porosity measured from the sonic log, resistivity log, or d-exponent 1 (Flemings, 2021). Shale formations show a direct relationship between porosity and pore pressure as a function of depth in many youthful, rapidly subsiding basins where there are high sedimentation rates (Osborne and Swarbrick, Flemings). Most empirical methods for pressure prediction are based on shale behaviour where there is a high clay mineral fraction. However, carbonates have a totally different set of behaviours during burial. They may have greater bulk stiffness and compressibility and may differ in their relationship between porosity and overpressure (Morales et al. 2018).

A pore pressure estimation at Anhelido-1 was made previously in 2012 using the Eaton method (Eaton, 1975). However, Eaton's method does not effectively correct pore pressure for carbonate and highly cemented shale lithologies, since it was designed for application on unconsolidated clastic sediments typical of Tertiary deltas such as the Mississippi Delta (Eaton, 1975).

The law of effective stress describes the relationship between the total stress (S_v), pore pressure and effective stress and was presented by Terzaghi in 1943 (eq. 6.1). This equation is fundamental for our

understanding of the relationship between velocities, porosity, and stresses during the burial of sediments.

$$S_v - P_p = \sigma \quad (6.11)$$

According to the stress map of the study area (see section 4.3.4.2 in Chapter 4 Figure 4.22), the maximum stress orientation is approximately NE-SW. From the fault regime for the area, we can assume that the maximum principal compressive stress is vertical (Figure 6.31). This vertical stress can be computed integrating the density log over depth and using the average velocity obtained to derive the vertical stress at any depth:

$$S_v = \rho g z \quad (6.12)$$

Where ρ = *bulk density*

g = *9.8 acceleration due to gravity*

In this project I adopt the Atashbari et al., (2012) approach that has been used in carbonate rocks by virtue of the predominantly carbonate facies that characterise the intervals of main interest for shale gas exploitation (see section 5.2.3 in Chapter 5 Table 5.1).

Atashbari et al., (2012) developed the compressibility method which starts with an analysis of pore fluid and rock compressibilities and enumerated a list of pore pressure mechanisms (Table 6.3).

Pore Pressure is very important parameter for the well control in terms of reservoir fluid properties. In this new method, the pore pressure was obtained using the compressibility attribute of reservoir rock.

In most of overpressure mechanisms may generate a detectable amount of overpressure are in the favour (seal and time). During burying the deposition of overlaying formation increment its rate an excess pressure on the reservoir which leads its compaction.

This new technique could be used to validate the pore pressure prediction methods or as a diagnostic analysis for compaction trend. In this development the compressibility tests were done on the core samples in the lab which is a kind of limitation due to the stresses have been removed already. In this work it was applied within Pimienta Formation where; thus, permanent rock deformation is probable in this condition.

Four types of compressibility for two independent volumes and pressures were introduced by Zimmerman in 1991.

1	Loading
2	Hydrology
3	Clay diagenesis
4	Tectonics
5	Chemical reactions
6	Kerogen transformation
7	Osmosis

Table 6.3 Pore pressure mechanisms.

Based on the Zimmerman (1991) theory all the independent variables (Pore Pressure and confining pressure) can assume infinitesimally small and equal size and it is represented as follow:

$$dP_p = \frac{C_{bc}}{C_{bp}} dP_c \quad (6.13)$$

Pore pressure is proportional to the change in confining pressure times the compressibility ratio.

Using the Pore pressure approach from Morales, (2014) applied to Anhelido-1 where the minimum logs required for that estimation were density-porosity log (DPHI) and bulk density (RHOB), the

interval depth of the formation (carbonate-limestone) and mineral proportion XRD), finally the equations demonstrated by Van Golf-Racht (1982) are proposed:

$$C_b = (1 - \phi)C_r \quad (6.14)$$

$$C_p = \frac{(1 - \phi)}{\phi} C_r \quad (6.15)$$

Compressibility of pore space can be written assuming absence of horizontal compaction as:

$$C_p = \frac{1}{2} \frac{(1 - \phi)}{\phi} C_r \quad (6.16)$$

To calculate the compressibility of the rock matrix C_r the bulk modulus (K_r) of the matrix rock should be estimated from mineral proportions XRD data.

$$C_r = \frac{1}{K_r} \quad (6.17)$$

Finally pore pressure in carbonate formations can be derived by the next equation:

$$P_p = \left(\frac{(1 - \phi)C_b}{(1 - \phi)C_b - \phi C_p} \sigma_{eff} \right)^\gamma \quad (6.18)$$

The empirical constant γ varies from 0.9 to 1 using psi of pressure and it was proposed by Atashbari et.al., (2012).

Assuming a tectonically passive state of stress (maximum stress is vertical), the magnitude of horizontal stresses can be estimated using P_p and the vertical stress using the Poisson's Ratio and Biot's coefficient (α) and is expressed by:

$$S_{hmin} = \left(\frac{v}{(1 - v)} \right) (S_v - \alpha P_p) + \alpha P_p \quad (6.19)$$

$$S_{Hmax} = 3S_{hmin} - \left(S_v \frac{v}{(1 - v)} \right) + P_p + UCS \quad (6.20)$$

The static Uniaxial Compressive Strength (UCS) has been taken from the triaxial analysis and corrected using Neutron-Porosity) NPHI log. This correction is used for more accurate SHmax calculation (Figure 6.11). Biot's coefficient was estimated using permeability and porosity from core and log data using Kief's approach (Kief et.al., 1990) to estimate the skeleton (dry) bulk modulus from the effective porosity and the solid bulk modulus from the e.q. (6.21) (Figure 6.12).

$$\alpha = 1 - \frac{K_{skeleton}}{K_{solid}} = 1 - (1 - \phi)^{\frac{3}{1-\phi}} \quad (6.21)$$

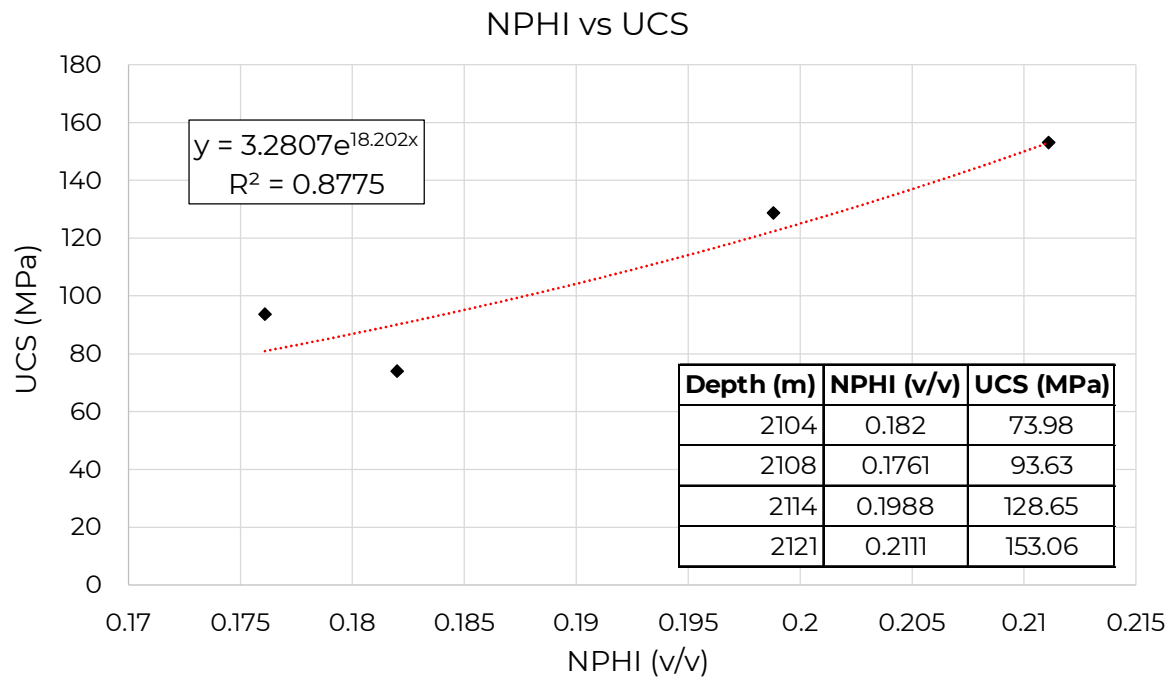


Figure 6.11. Static UCS from triaxial analysis and its correction using NPHI log at Anhleido-1 within Pimienta Formation.

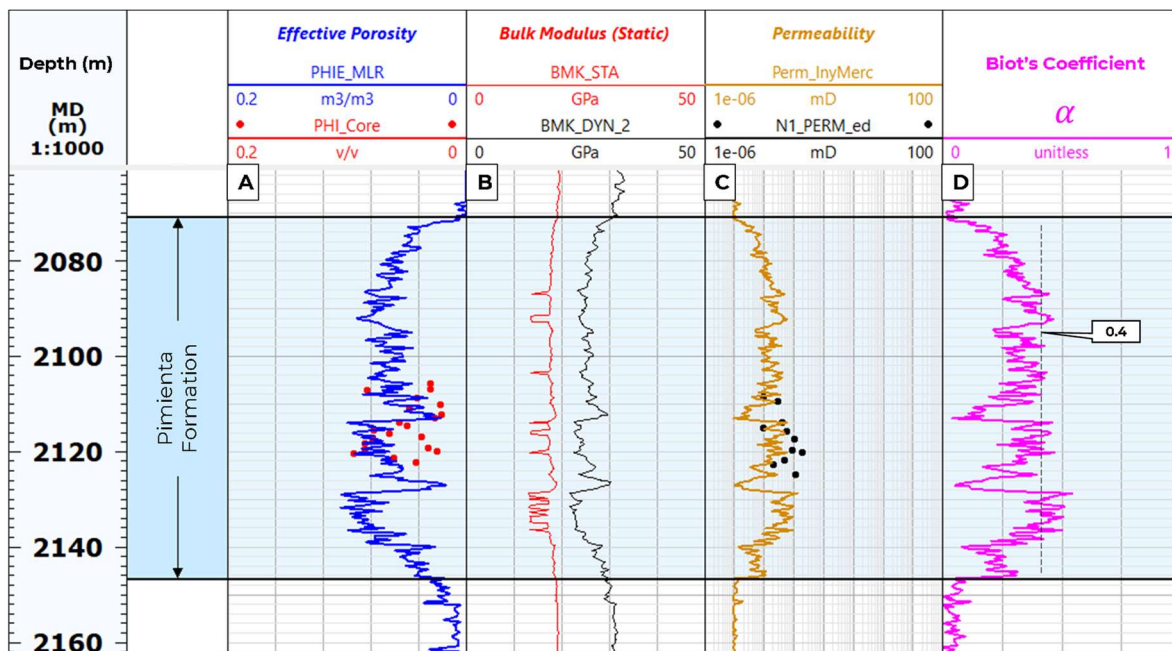


Figure 6.12. Biot's coefficient estimation within Pimienta Formation; (A) Effective porosity from log and CORE; (B) Static and dynamic Bulk Modulus; (C) Permeability log and mercury injection samples; (D) Biot's coefficient with 0.4 average (black dashed line).

6.2.4.2 Differential horizontal stress ratio

The stress results have been used to calculate the differential horizontal stress ratio DHSR (stress variations) (Gray et.al., 2012) (Tables 6.4 and 6.5), the workflow for DHSR is shown in Figure 6.13 and 6.14. This attribute is used to assess optimal hydraulic fracturing locations through seismic data.

$\sigma_H > \sigma_h > \sigma_z$	Thrust= Horizontal fractures that move horizontally, much overburden allows them to go up
$\sigma_H > \sigma_z > \sigma_h$	Shear=Vertical fractures that move horizontally
$\sigma_z > \sigma_H > \sigma_h$	Normal=Vertical fractures that move vertically

Table 6.4 Stress variations with depth (after Zoback)

If $S_{Hmax} \approx S_{hmin}$ ($DHSR \approx 0$) (Figure 6.10A)	Tensile cracks in any directions will form
	• Parallel to rock weakness • Fracture network might occur
If $S_{Hmax} \gg S_{hmin}$ (Figure 6.10B)	• Fractures will be parallel to the direction of maximum stress
	• Shear fractures • Tensile fractures • It might connect to existing fracture network for production • Tensile cracks in any directions will form

Table 6.5 Parameters for DHSR to assess optimal hydraulic fracturing locations through seismic data (Gillot, 2014 (Baker Hughes & CGG alliance))

Where

$$DHSR = \frac{S_{Hmax} - S_{hmin}}{S_{Hmax}} \quad (6.22)$$

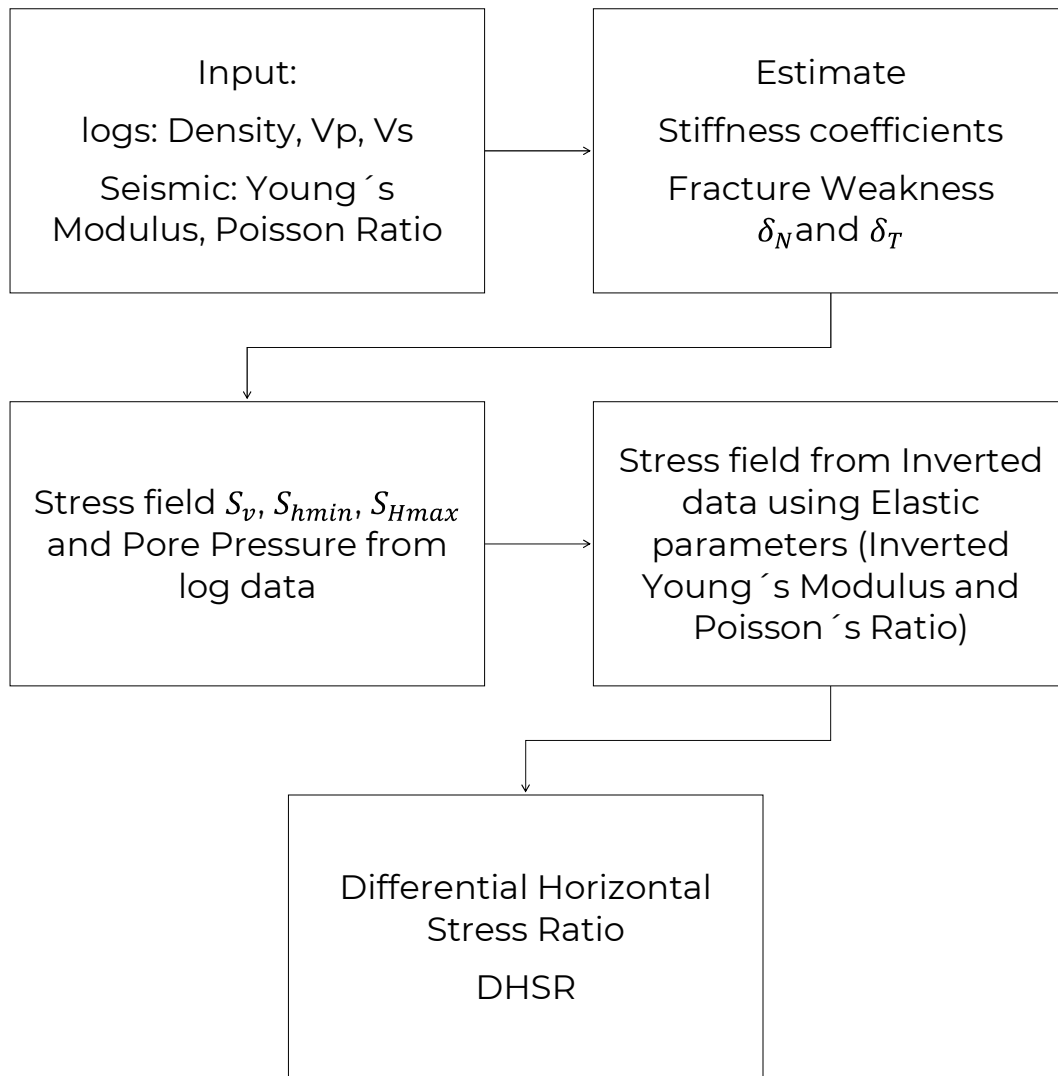


Figure 6.13. Workflow to estimate DHSR

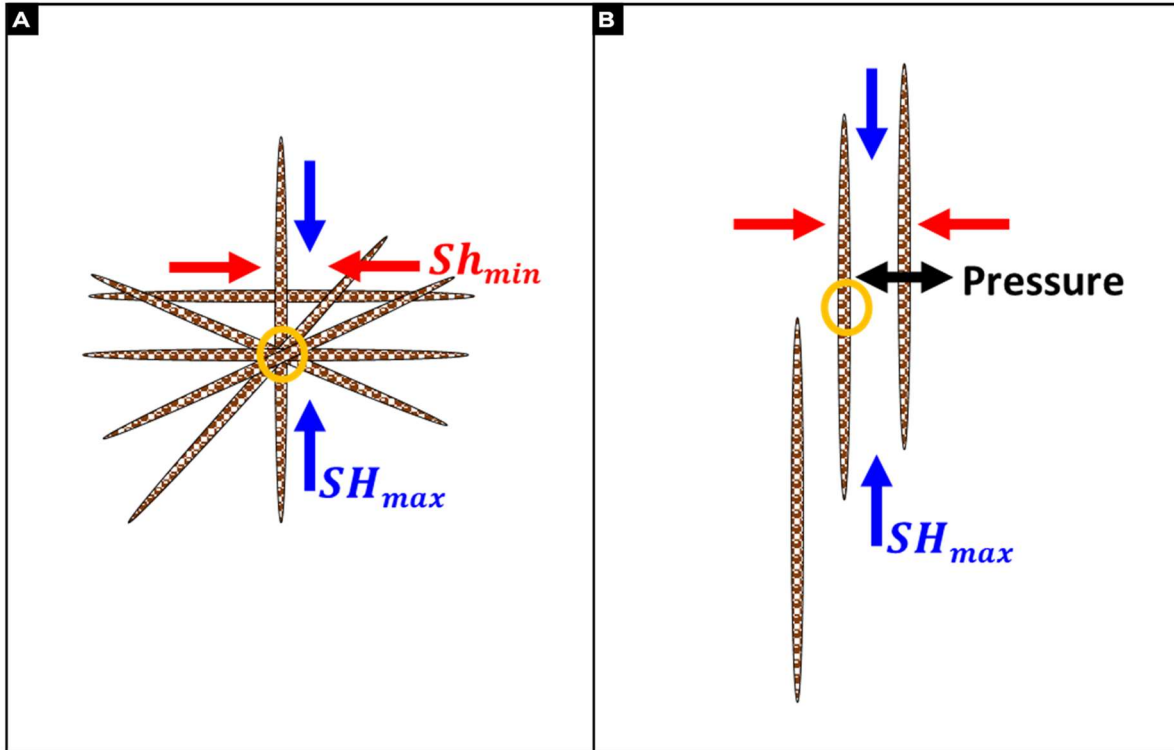


Figure 6.14. (A) Tensile cracks will form in omnidirectional way; (B) Fractures parallel to the maximum horizontal stress will form (Gillot, 2014; Baker Hughes & CGG alliance).

6.3 Results

The inversion along the Anhelido-1 well was performed at each azimuth sector 50ms above the top of the reservoir and 50ms below the bottom of the reservoir. The depth of the Pimienta Formation is between 2070m and 2140m (highlighted yellow, Figure 6.15). This interval is characterised by relative decrease in both P and S impedance. This change is due to the overlying and underlying layers being carbonate rocks, with sonic log measurements of P wave velocities about 6100 m/s.

For the four angle sectors 16 wavelets have been used. The resulting correlation coefficient is an average of 0.95. This correlation suggests that the inverted traces and the estimation of the wavelet is correct and that the inversion from this well can be further expanded to the entire volume.

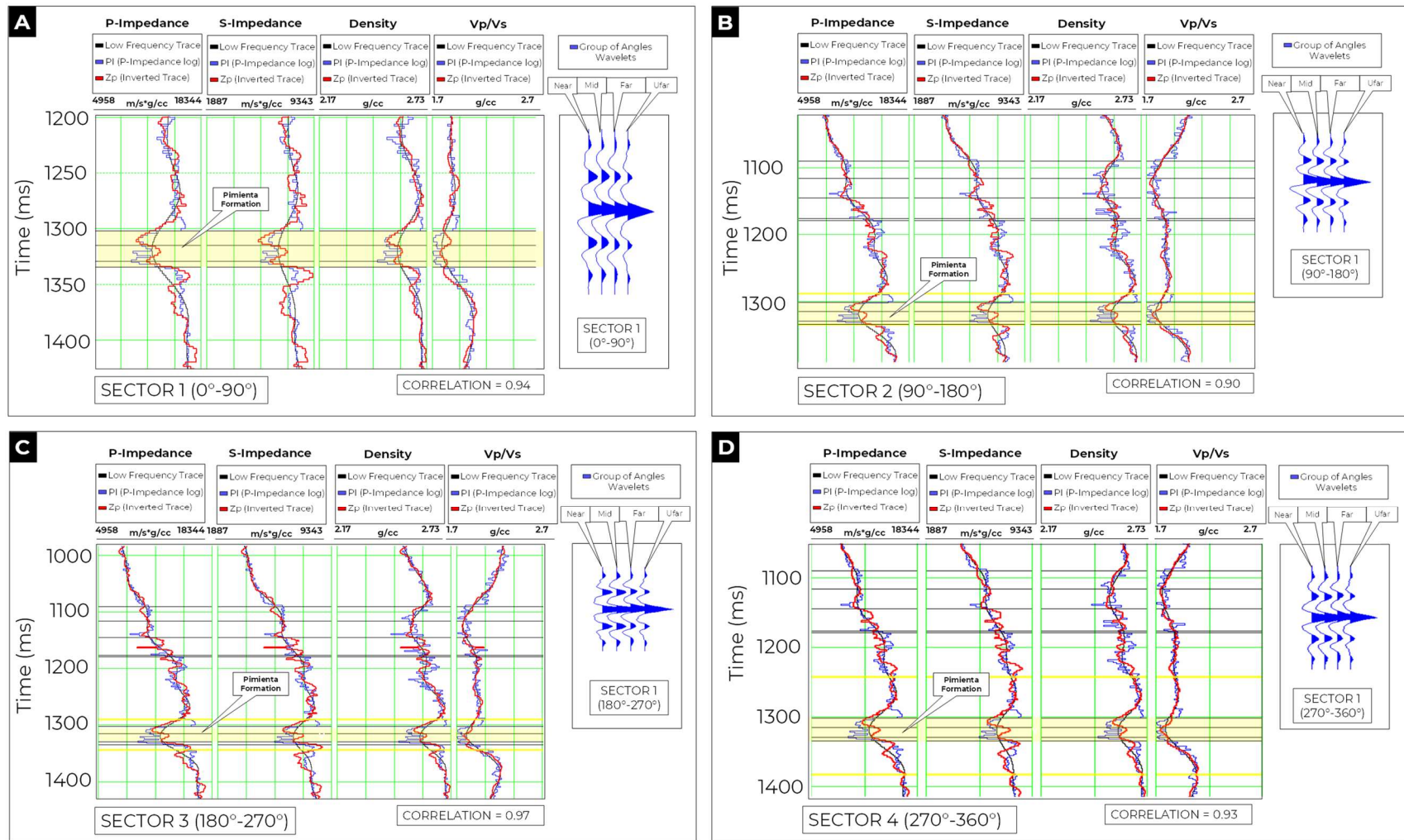


Figure 6.15. Inversion results in azimuthal sectors (e.g., P-Impedance, S-Impedance, Density and VpVs ratio) at well location Anhelido-1. In each sector it is shown the low-frequency curve (black), log response (blue) and the inverted trace (red), the correlation for all azimuth sectors are above >90% and four angle dependent wavelets are shown in blue colour from near to far incidence angle; (A) Inverted result at Sector 1 (0°-90°); (B) Inverted result at Sector 2 (90°-180°); (C) Inverted result at Sector 3 (180°-270°) and finally; (D) Inverted result at Sector 4 (270°-360°)

6.3.1 Well trace inversion

In order to better assess the quality of the results of inversion along the initial well traces the scattering plot of P-Impedance (log) is compared with the resulting inverted P-Impedance and $\frac{V_p}{V_s}$ Ratio. The correlation results are presented in Figure 6.16. The linear regression shows an excellent result in all the tested sectors.

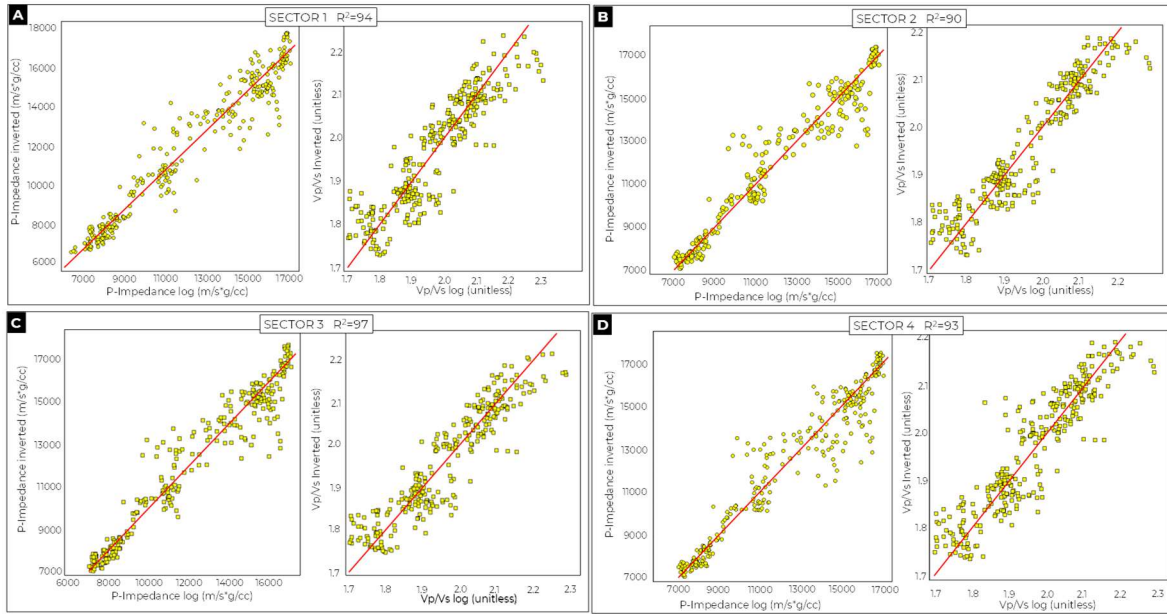


Figure 6.16. Regression lines and its correlation in linear behaviour between P-impedance inverted vs. P-impedance log and $\frac{V_p}{V_s}$ log vs. $\frac{V_p}{V_s}$ inverted data per azimuth sector; (A) Crossplot in Sector 1 (0°-90°) (R²=94); (B) Crossplot in Sector 2 (90°-180°) (R²=90); (C) Crossplot in Sector 3 (180°-270°) (R²=97); (D) Crossplot in Sector 4 (270°-360°) (R²=93); The impedance volumes P-S for each azimuthal sector were obtained with an excellent correlation these volumes will be of great importance to be used in the TOC upscaled equation since the aim is derive impedance attribute maps (Z_p , Z_s), per azimuth within the Pimienta Formation.

The azimuthal seismic inversion along the Anhelido-1 well was performed at each azimuth sector 50ms above the top of the reservoir and 50ms below the bottom of the reservoir. The depth of the Pimienta Formation is between 2070m and 2140m (yellow polygon, Figure 6.15). This interval is characterised by relative decrease in both P and S Impedance due to Pimienta Formation is encased between two high velocity formation (Tamaulipas Formation and Olvido Formation respectively).

6.2.3 Azimuthal estimation of TOC from inverted seismic data

In order to estimate the TOC for each sector I have introduced the azimuth as an extra dimension into the well-known Vernik's (2002) equation for TOC estimation. This novel method will be referred to here as Upscaled Anisotropic TOC. This equation will use as input S-Impedance (Z_s) and P-Impedance (Z_p) from entire azimuthal sectors, and b and a_0 which were taken from the scattering regression line along the P-Impedance & S-Impedance from well log in the reservoir zone (Figure 6.17). TOC_{ref} and a_{ref} comes from the values of the study area shown in Figure 6.18. The new equation for upscaled anisotropic TOC as a function of azimuths is:

$$TOC(\phi) = \left[\frac{(Z_s(\phi) - bZ_p(\phi)) - a_0}{a_{ref} - a_0} \right] TOC_{ref} \quad (6.23)$$

Z_s – Inverted S – impedance

Z_p – Inverted P – impedance

ϕ – Azimuth

TOC_{ref} – TOC reference of project area

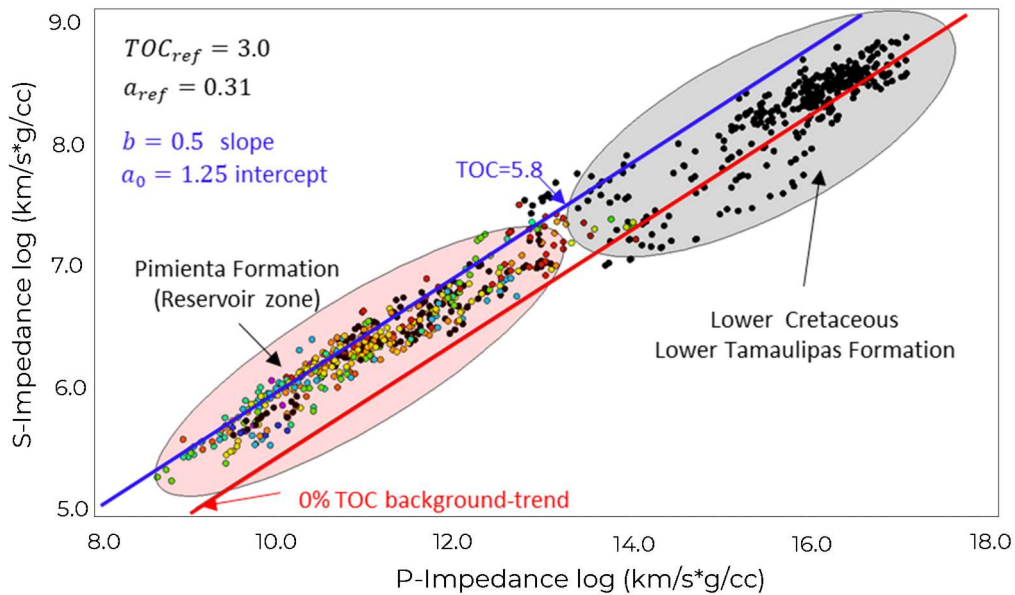


Figure 6.17. PI-SI scattering template, showing log derived impedances and TOC values in Anhelido-1. Superposed are: (1) zero-TOC background-trend red line regression and 5.8% TOC (blue line).

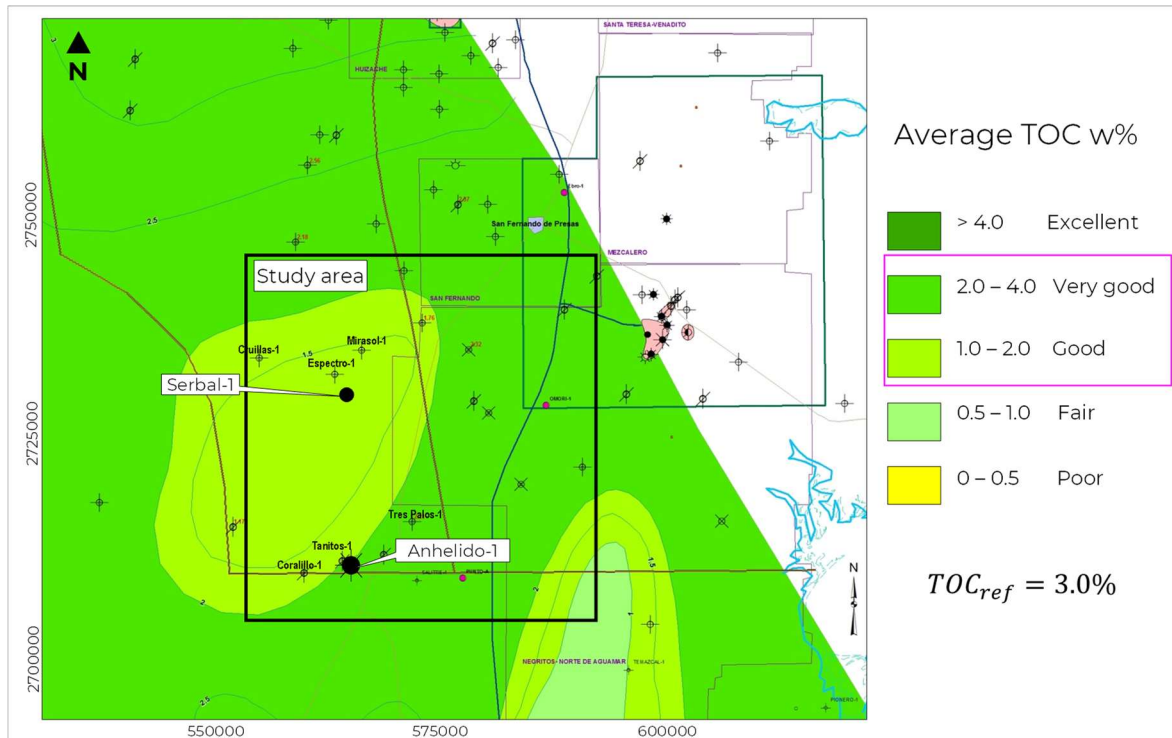


Figure 6.18. TOC regional Map from study area, source (PEMEX E&P, 2015) The map was obtained from the results of pyrolysis performed on the well samples of the study area. For Regional area, it was observed that it is found with average values in the range of >3% within the study area.

Using the inverted azimuthal impedances of the inversion process, as shown in Figure 6.19, the impedances are then compared with the logs of Impedances with a frequency filter (10Hz-50Hz). An excellent agreement is observed between the inversion from the logs (Anelido-1) and the inverted seismic volumes. The impedances values within Pimienta Formation exhibit P-Impedances in the range of 9000-11000 (m/s*g/cc) and the S-Impedances in the range of 4500-6500 (m/s*g/cc).

These results have been used as input for the estimation of upscaled TOC eq. (6.23).

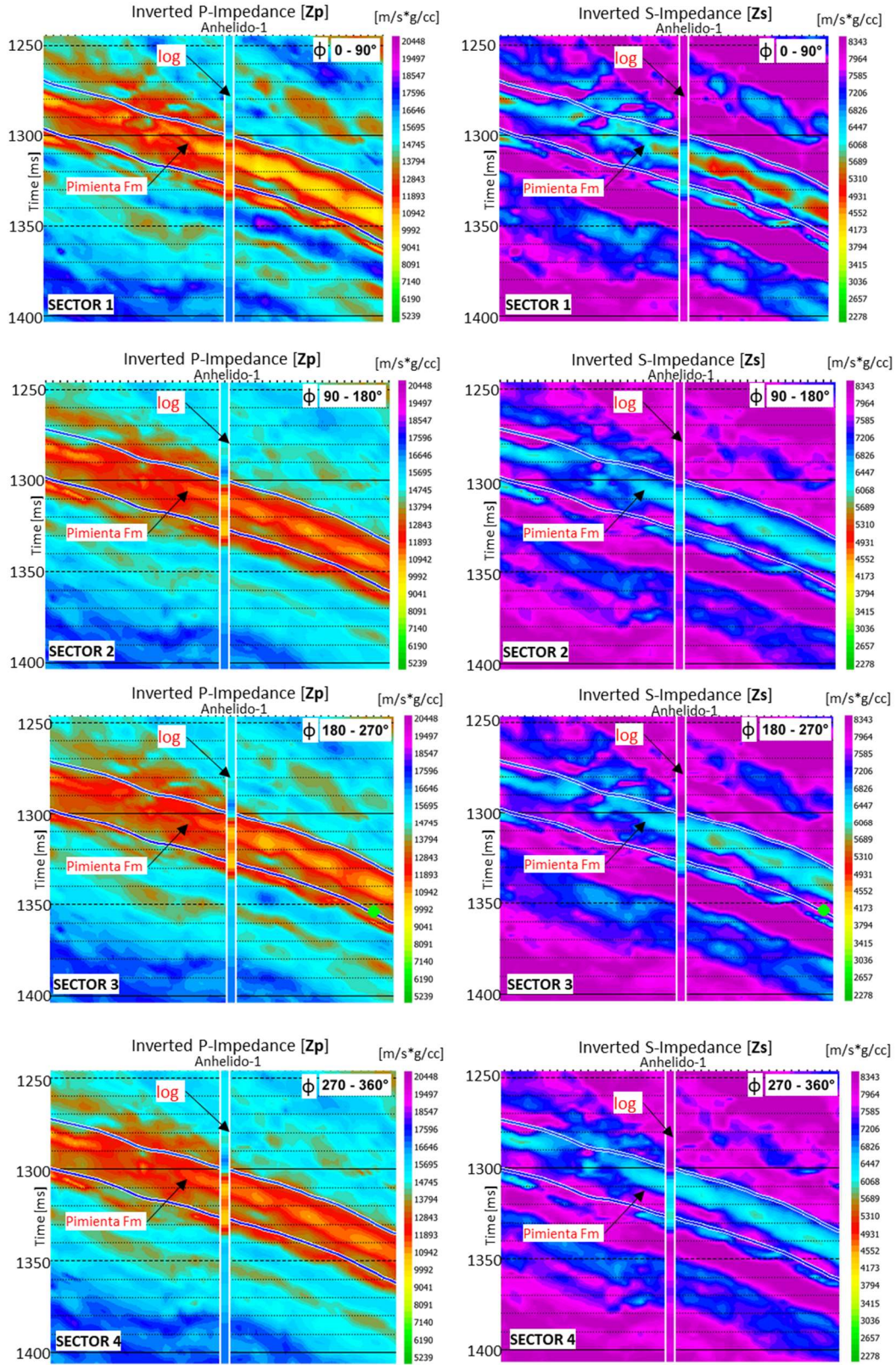


Figure 6.19. The Inverted P-Impedance (Z_p) & S-Impedance (Z_p) results for each sector where ϕ is the azimuth and the Impedances logs P and S overlapped in the seismic image with excellent agreement between P-S Impedance logs and inverted traces.

The results show notable changes for each azimuth sector. The TOC increases systematically from 0°-90° to 270°-360° degrees azimuth with a variation from 5.5% TOC percentage points observed towards the eastern portion of the analysed volume to around 6%. It is worth mentioning that these results were estimated, considering the geochemical information of the study area (Figure 6.18).

These results are taken to suggest that the TOC content may induce anisotropy as a function of impedances in inverted volumes. This important point is addressed further in the discussion section.

For example, in SECTOR 1 (0°-90°) low values in TOC between (5-5.5) may be noted in the eastern part of the horizontal well navigation. For SECTOR 2 (90°-180°) the TOC values increase in a range of 5.7% to 6.9% mostly. In SECTOR 3 (180 ° -270 °) the TOC ranges are in the order of 5.5 to 6.5 and finally in SECTOR 4 (270 ° -360 °) TOC exhibits similar values to Sector 3 of between 5.5 and 6.5.

On average for the Pimienta Formation the TOC values are in the order of 5% to 7% mostly, according to the TOC maps extracted at each azimuth shown in Figure 6.20. These values are corroborated with the histogram of TOC values in the well Anhelido-1, where the values go from 1% to 7% within the Pimienta Formation (depth range 2072-2146m) (Figures 6.21 and 6.22).

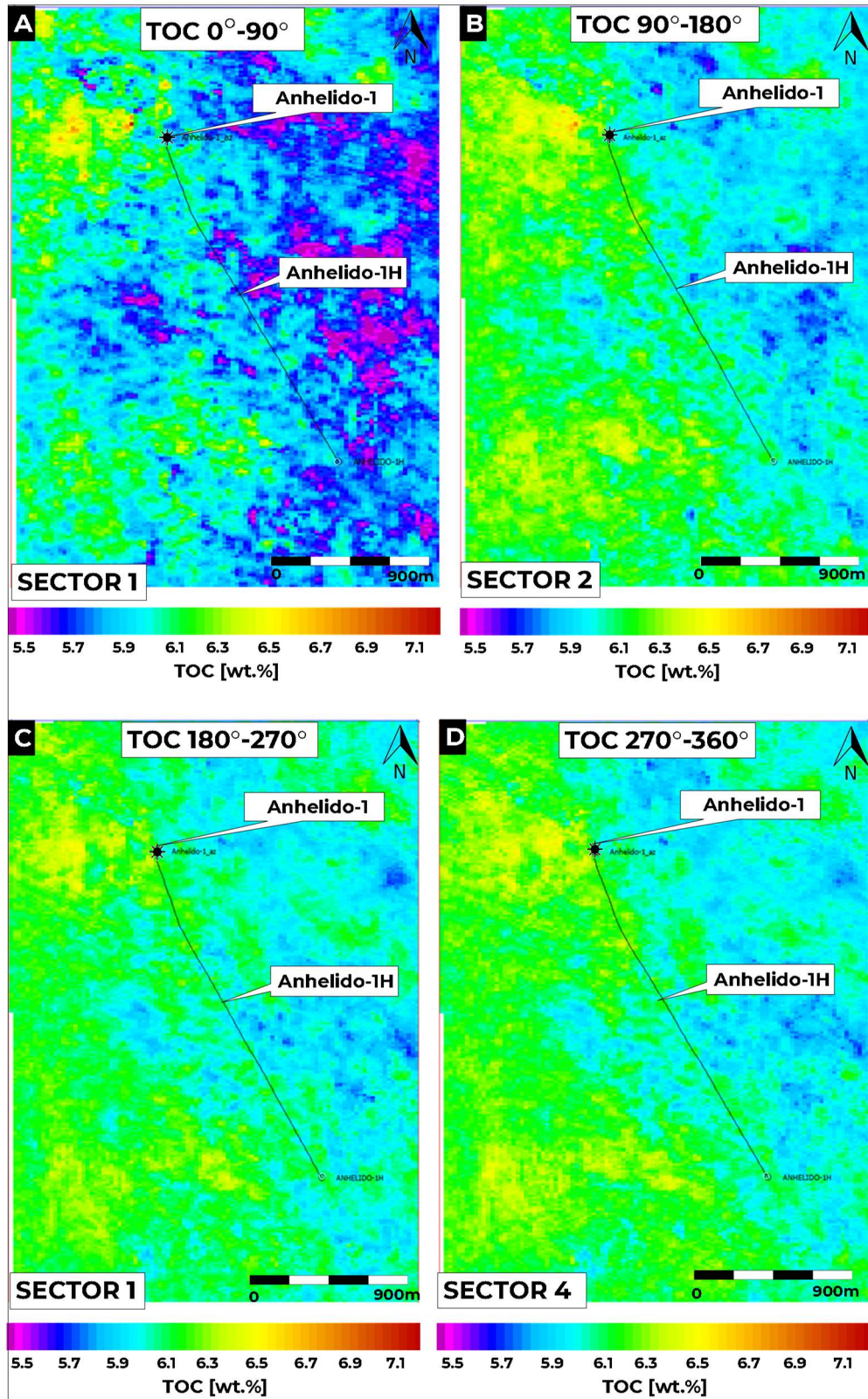


Figure 6.20. Azimuthal upscaled TOC in sub seismic volumes per sector around Anhelido-1 and Anhelido-1H; (A) TOC at Sector 1 (0 ° -90 °); (B) TOC at Sector 2 (90 ° -180 °); (C) TOC at Sector (180 ° -270 °); (D) TOC at Sector 4 (270 ° -360 °).

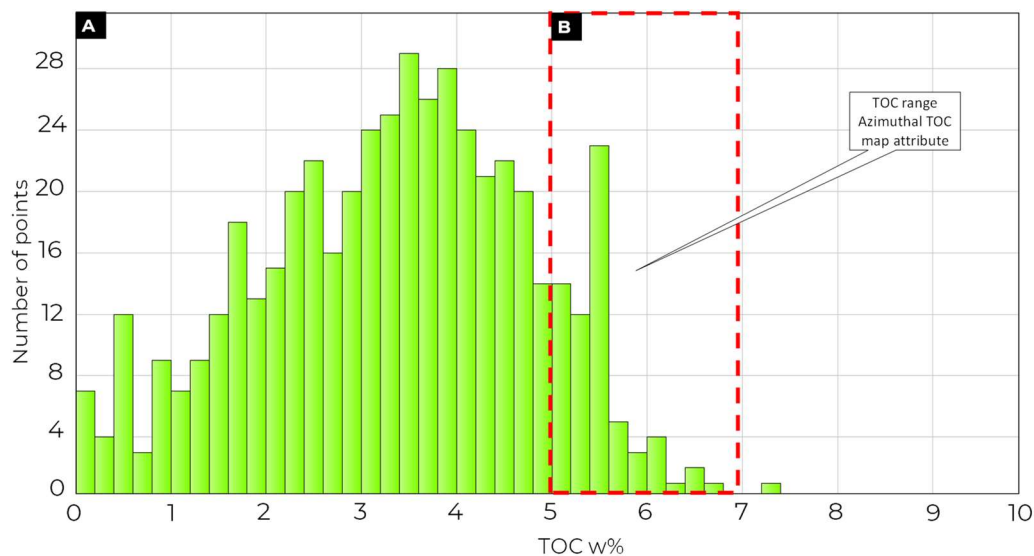


Figure 6.21. (A) histogram of TOC content within Pimienta Formation from well log information and RockEval; (B) Range of TOC found within the inverted TOC data in four azimuth sectors, the range between 5% and 6.5% in average (Figure 6.21).

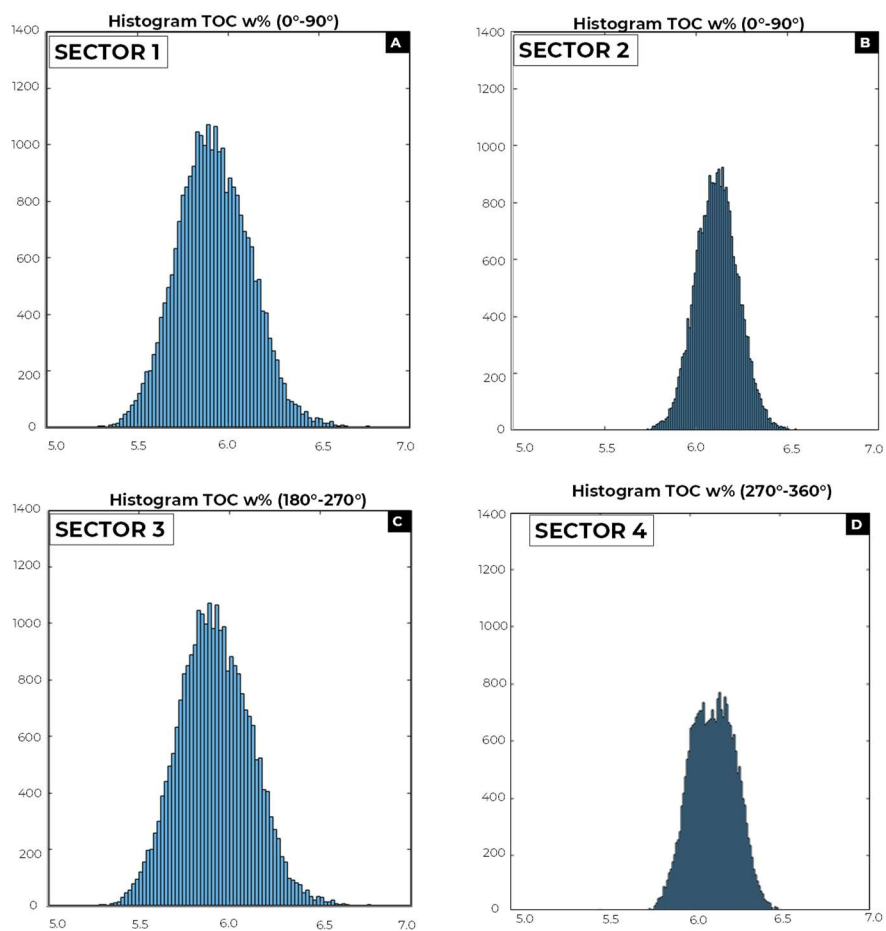


Figure 6.22 (A) TOC surface attribute histograms at Sector 1 (0°-90°); (B) TOC surface attribute histogram at Sector 2 (90°-180°); (C) TOC surface attribute histogram at Sector 3 (180°-270°); (D) TOC surface attribute histogram at Sector 4 (270°-360°).

6.2.3 Anisotropic Young's Modulus and Poisson's Ratio

The triaxial tests provided by Pemex conducted on the Pimienta Formation have been used to calculate the static Young's Modulus. The method explained in the method section (6.2.2), was applied to tests on four samples within the Pimienta Formation (Depth: 2104m, 2108m, 2114m, and 2121m) (Figure 6.23). To determine the cut-off from the brittle/ductile line to constraint the average Young's Modulus from the inverted data, the average value of the static and dynamic Young's Modulus was found to be approximately 19GPa which is the average value estimated between triaxial analysis and dynamic values shown in table 6.6 on the four samples within the Pimienta Formation.

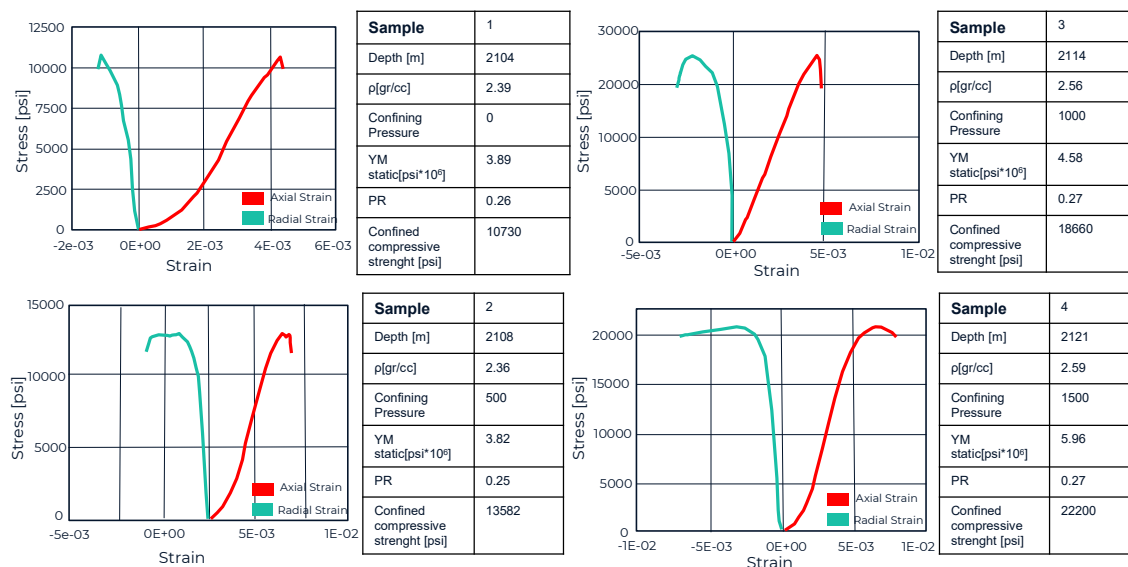


Figure 6.23. Triaxial test samples of stress-strain curves to estimate the static Young's Modulus as a cut-off of elastic limit on seismic inversion to find the best mechanical properties within Pimienta formation, considering this, I have defined the values of $E < 19\text{GPa}$ as a ductile, rock and $E > 19.5\text{GPa}$ as a brittle rock.

The results from this analysis, summarized in Table 6.6 have been also shown in Figure 6.24 to highlight the relationship between the Static and Dynamic Young's Modulus but also to obtain friction angle and cohesion from Mohr Coulomb envelope through four samples within the reservoir.

Sample Number	Depth (m)	Confined Pressure (psi)	Density (gr/cc)	Compressive Strength (psi)	Static Poisson's Ratio	Static Young's Modulus (GPa)	Dynamic Young's Modulus (GPa)
1	2104.73	0	2.38	10730	0.25	26.84	38.26
2	2108.69	500	2.35	13582	0.25	26.37	43.31
3	2114.95	1000	2.55	18660	0.26	31.55	39.59
4	2121.12	1500	2.59	22200	0.26	41.12	35.97

Table 6.6. Dynamic & Static moduli comparison at Anhelido-1

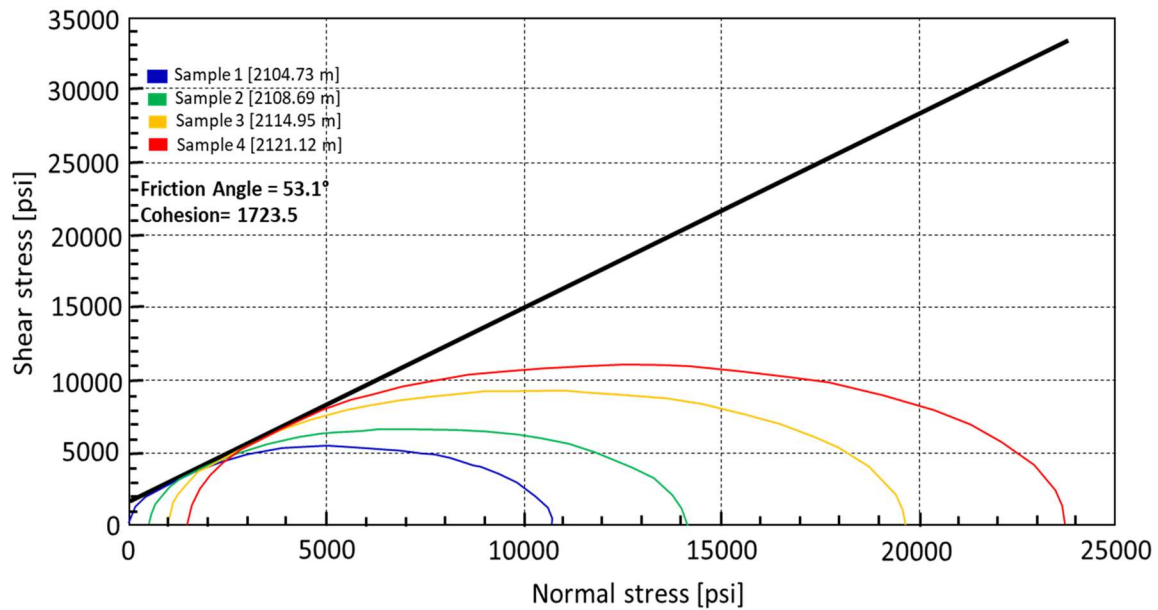


Figure 6.24. Mohr's circles through different unconfined pressure test in four samples within the Pimienta Formation to obtain the friction angle and cohesion.

As expected, dynamic Young's Modulus overestimates rock stiffness (e.g., depths 2104 m sample 1 and 2108 sample 2) and that is normal because the difference between static and dynamic moduli is high at low pressure and decrease with increasing with stress which shows the difference between static and dynamic Young's Modulus. Sample 3 and 4 at depths 2114 m and 2121 m fit reasonably well with the dynamic Young's Modulus as shown in Figure 6.25. Finally, the correction of Young's Modulus and Poisson's Ratio are shown in Figure 6.26.

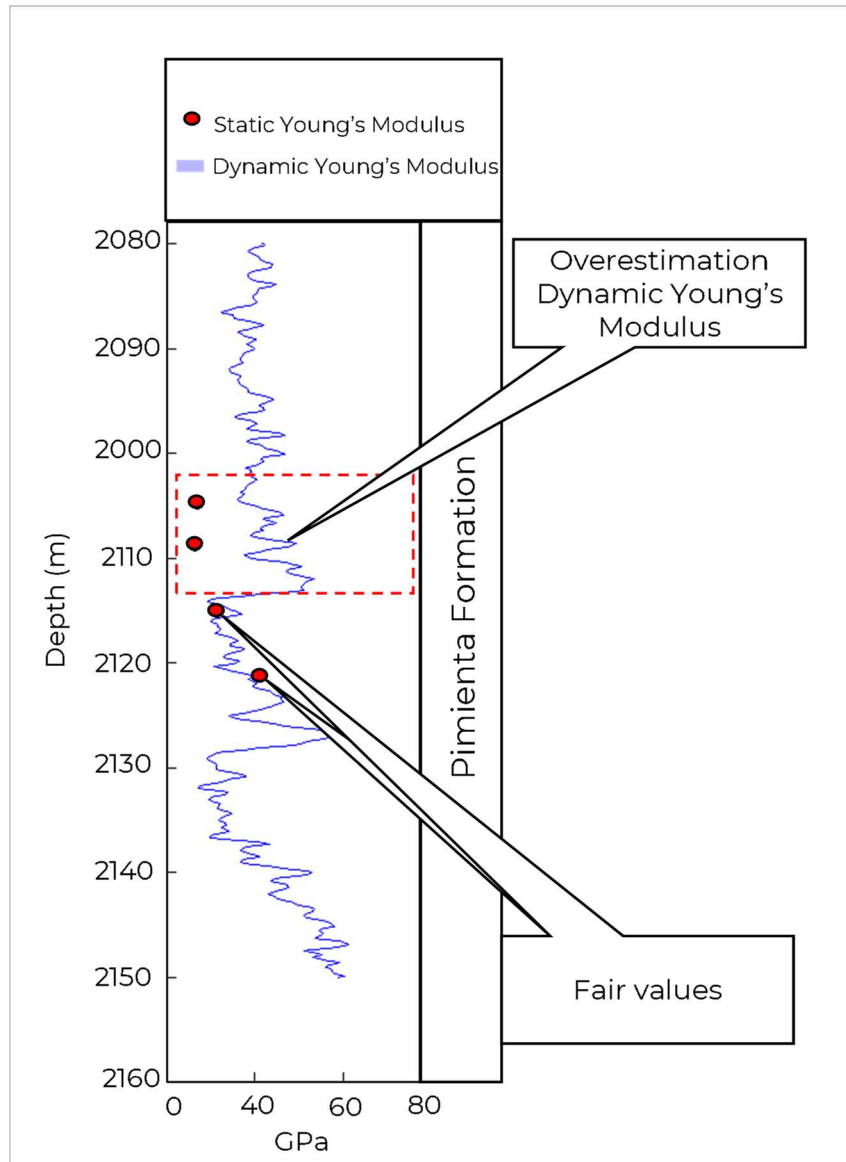


Figure 6.25 Static and Dynamic Young's Modulus comparison

In Figure 6.25, the correction of Young's Modulus and Poisson's Ratio based on the exponential estimation are approximately $R^2=59\%$ of correlation

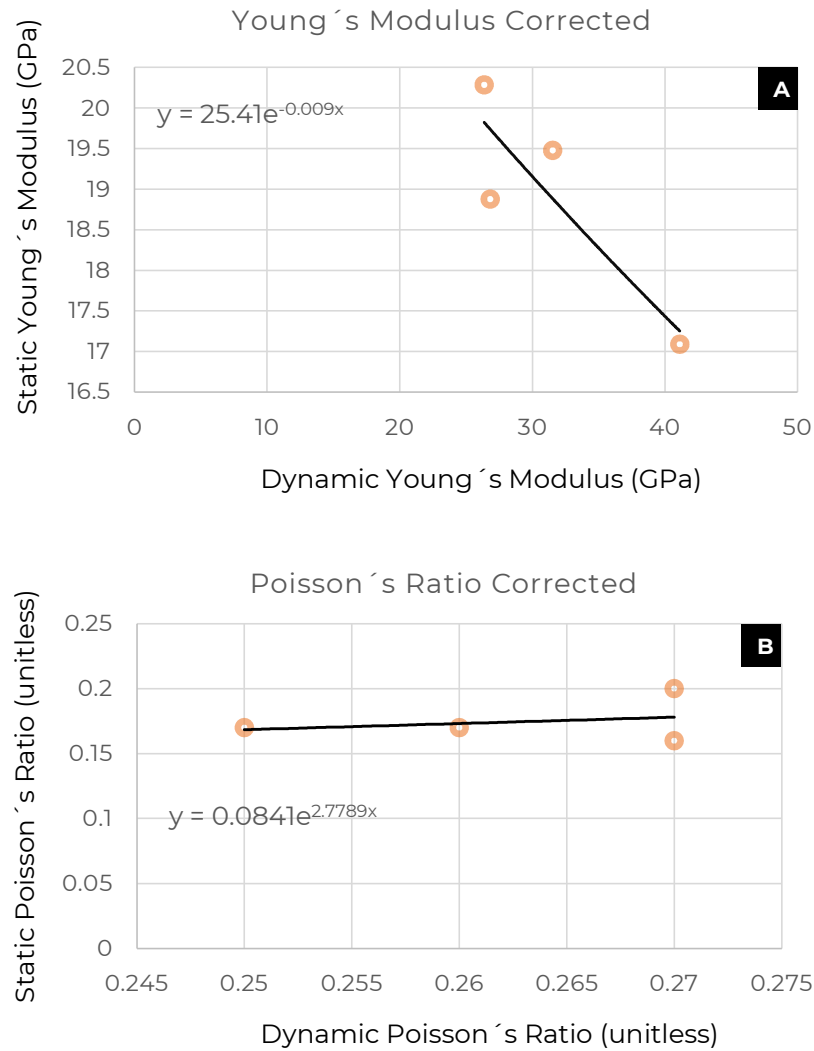


Figure 6.26. Dynamic vs Static Young's Modulus and Poisson's Ratio correction at Anhelido-1 (Pimienta Formation).

Using the dynamic and static Young's Modulus as input, it was possible to propagate these physical properties within the 3D inverted volumes (calibrated with the seismic).

In order to complete this task, the vertical and horizontal Poisson's Ratio and the vertical and horizontal Youngs' Modulus were computed (see Method, 6.2.2.1) The average Poisson ratio was calculated for the entire volume using the inverted seismic of each azimuth sectors as input.

The result of this operation is summarized in Table 6.7. The results shows that a both the minimum and maximum values are different for the different azimuths.

$\nu_{(0^\circ)_{min}}$	0.167606
$\nu_{(0^\circ)_{max}}$	0.231523
$\nu_{(90^\circ)_{min}}$	0.337342
$\nu_{(90^\circ)_{max}}$	0.570394

Table 6.7. Minimum and maximum values of vertical and horizontal Poisson's ratio respectively (from inverted volumes).

6.2.3 Anisotropic brittleness (Brit_V and Brit_H)

The anisotropic brittleness derived from inversion calculations is described with reference to the horizon intersecting the horizontal section of borehole Anhelido-1. The results, shown in Figure 6.27, comprises horizontal (90°) (Brit_H) and vertical (0°) (Brit_V) brittleness derived from 4 angle stack gathers and four azimuthal sectors. A total of 8 inverted volumes of brittleness were estimates, four in 0° VTI and four in 90° HTI.

The brittleness varies depending on the azimuth sector, in this case, the highest values in the sub-volumes are in the azimuth sector 2 (90° - 180°) in both anisotropic modes (VTI and HTI) as shown in Figure 6.27.

The results highlight that the highest values of brittleness occur when brittleness is estimated at 90° or parallel to the sedimentation. This observation is consistent for both horizontal and vertical inversion. This result could be related to the intrinsic shale anisotropy (lamination) in the Pimienta Formation parallel to the sedimentation (Qian, KR., Liu, T., Liu, JZ. et al. 2019). This interpretation will be presented in the discussion section of this chapter.

This analysis has also been extended along the horizontal section of the wellbore Anehlido-1 (Figure 6.28). The analysis reveals that the brittleness also varies for horizontal and vertical inversion.

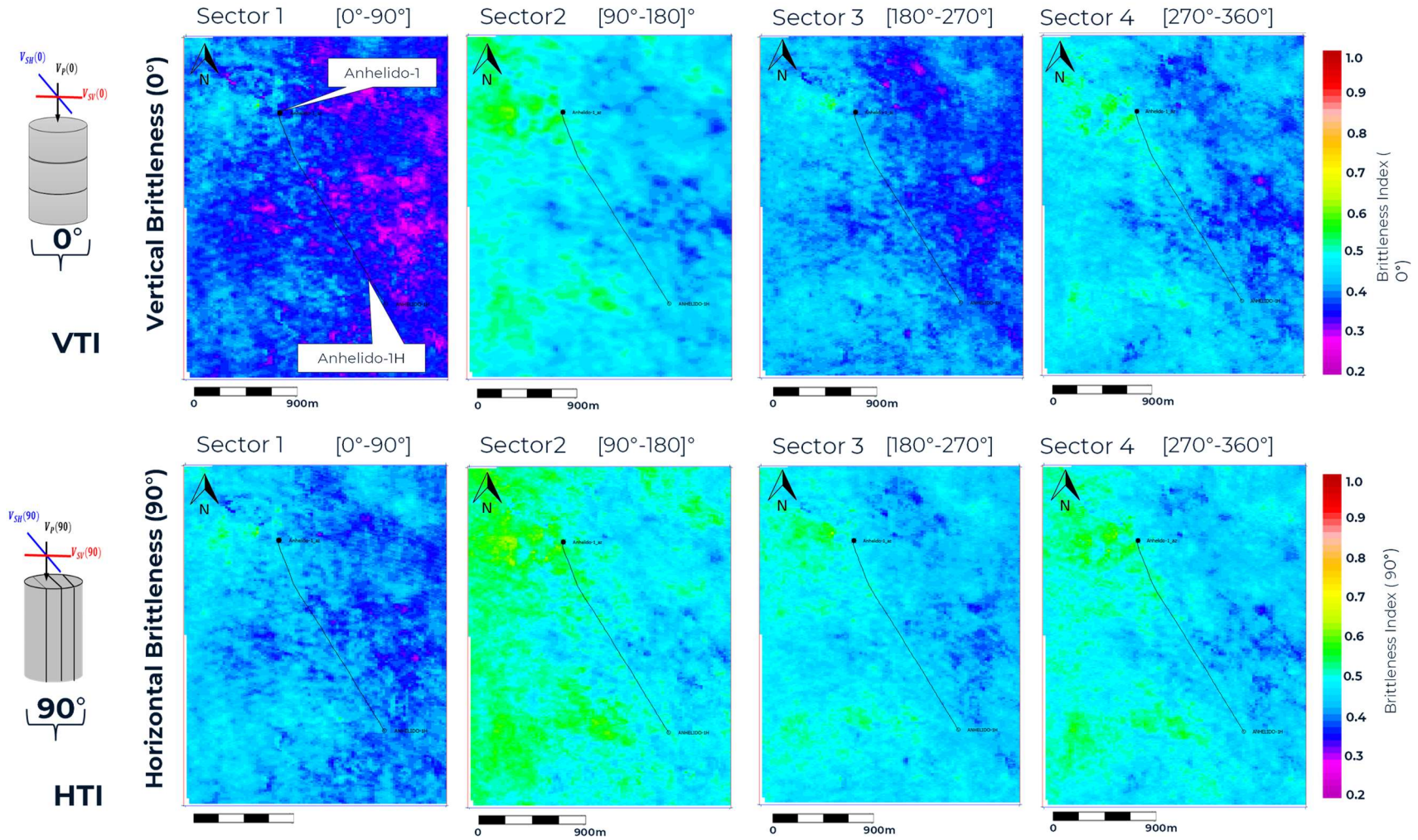


Figure 6.27. Horizontal Brittleness per azimuth in subvolume around horizontal wellbore side Anhelido-1. Note that the colour bar code is the same for all the maps corresponding to the reservoir zone as attribute map of amplitude RMS extraction which is roughly 80m.

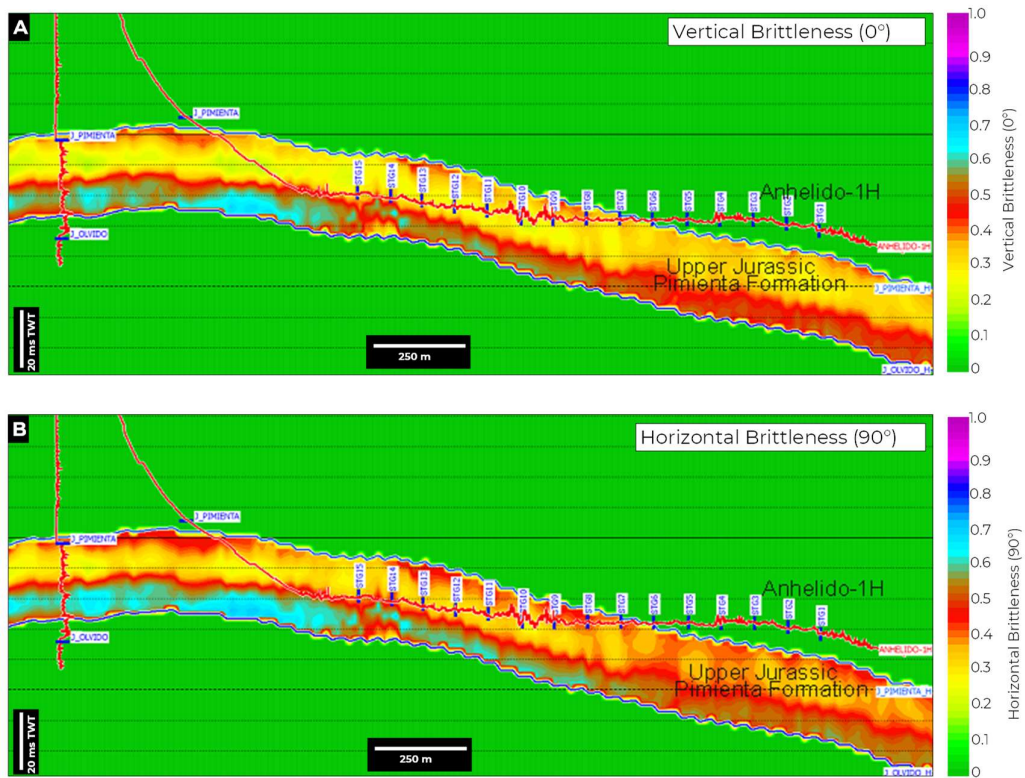


Figure 6.28. Anisotropic brittleness along the horizontal well side (Anhelido-1H)

6.2.4 Stress field

Comparison with the pore pressure prediction previously done using Eaton reveal the difference and the inaccurate result using this approach in Pimienta Formation at Ahelido-1. Figure 6.29 shows the Pore pressure estimation with Eaton equation.

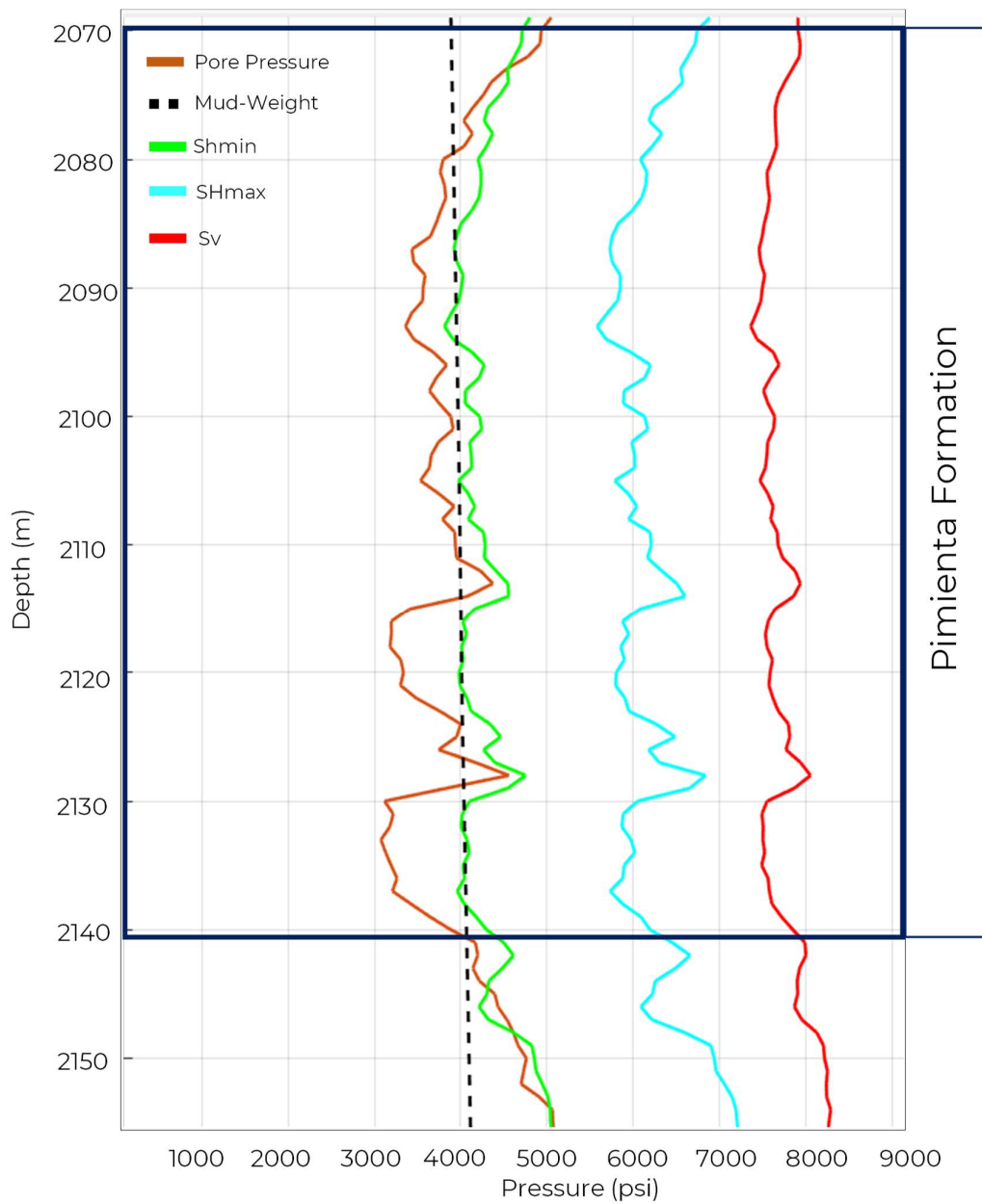


Figure 6.29. Pore pressure Prediction using Eaton approach.

Figure 6.30 According with the overpressure mechanisms in Anhelido-1 exhibit an apparent unloading trend of decreasing velocity with a range of density (2.4 g/cc - 2.7 g/cc) (Upper Cretaceous) which correspond with Lower Cretaceous, Pimienta Formation and Olvido Formation apparently show a undercompaction mechanisms, due to the increasing density and increasing velocity.

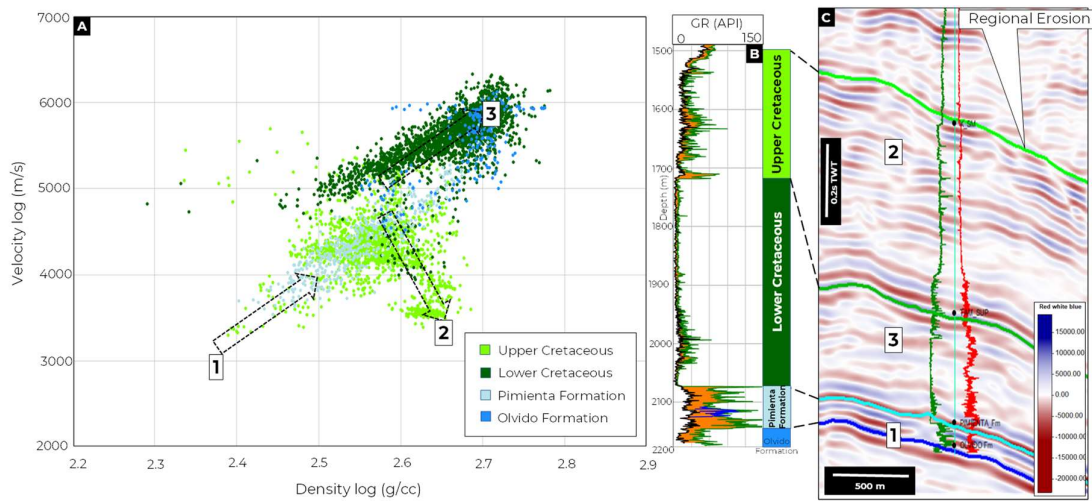


Figure 6.30. (A) Crossplot Density/Velocity at Anhelido-1 depth range (1500-2200m) to understand overpressure mechanism; (B) Gamma-ray log and geological column; (C) Representative seismic line, (1) Pimienta and Olvido Formation), (2) Upper Cretaceous and (3) Lower Cretaceous.

Taking into consideration the geological characteristics mentioned above and according with the Atashbari et al (2012) approach the pore pressure exhibit much better estimation in comparison with Eaton formulation. Figure 6.31 shows the resulting pore pressure calculation at Anhleido-1 within Pimienta Formation.

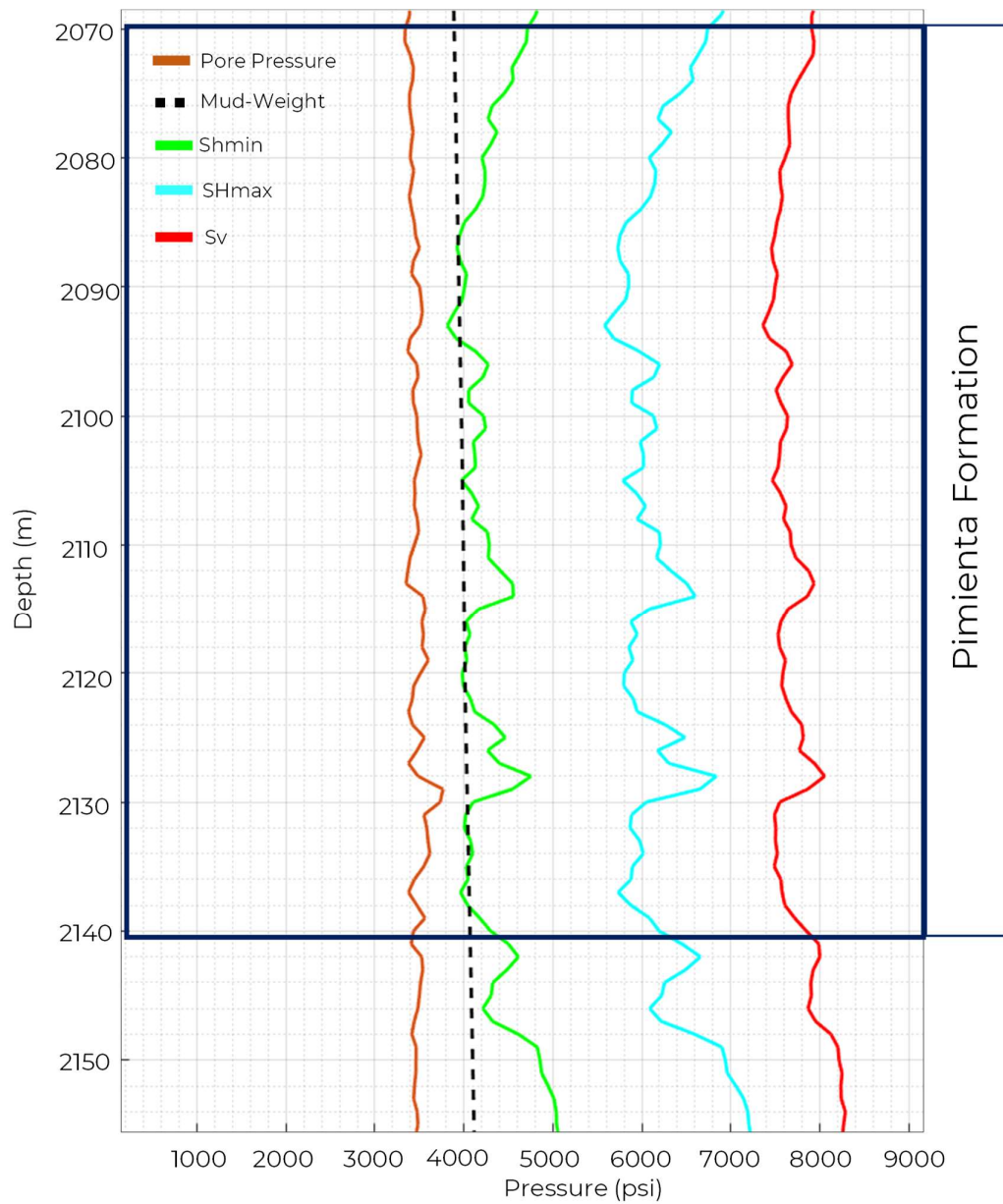


Figure 6.31. Pore pressure corrected using Atashbari et al (2012) approach.

Stresses field calculated in the well location at Anhelido-1 (Figure 6.31) is used for the estimation of stress field volumes through the elastic moduli inverted (e.g., Poisson's Ratio). Figure 6.32 shows the resulting volumes handled in Petrel.

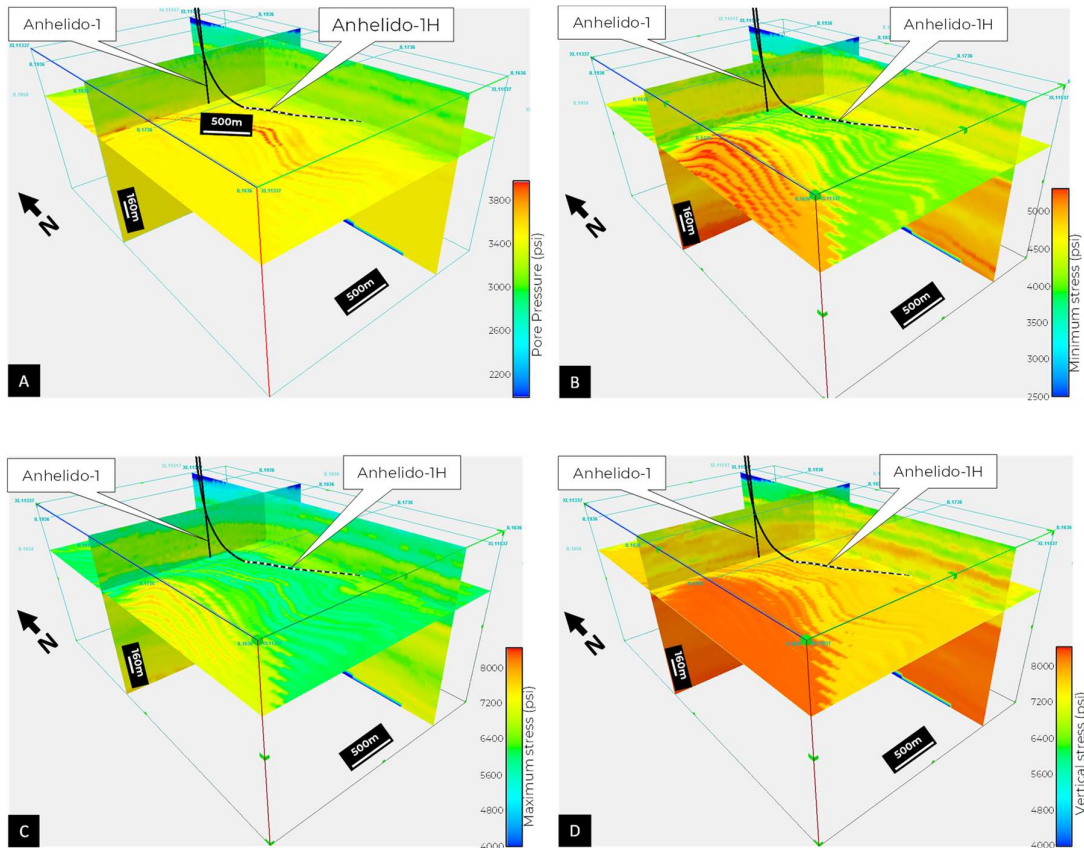


Figure 6.32. Volumes of stress field around Anhelido-1 and Anhelido-1H; A) Pore pressure volume; B) Minimum stress (S_{hmin}) volume; C) Maximum stress (S_{Hmax}) volume; D) Vertical stress (S_v) volume.

The resulting minimum horizontal stress shown in Figure 6.33 has been compared with the hydraulic treating test (Fracture Closure Pressure) in each stage at Anhelido-1H (horizontal wellbore) confirming a very good match with the minimum stress estimated from inverted seismic data (Figure 6.34). The Fracture closure pressure (FCP) represents the minimum principal stress (Yamamoto, 2003), it occurs when the stress in the formation and the pressure of fluid in the fractures have reached a state of mechanical equilibrium Table 6.8 shows such difference in pressure.

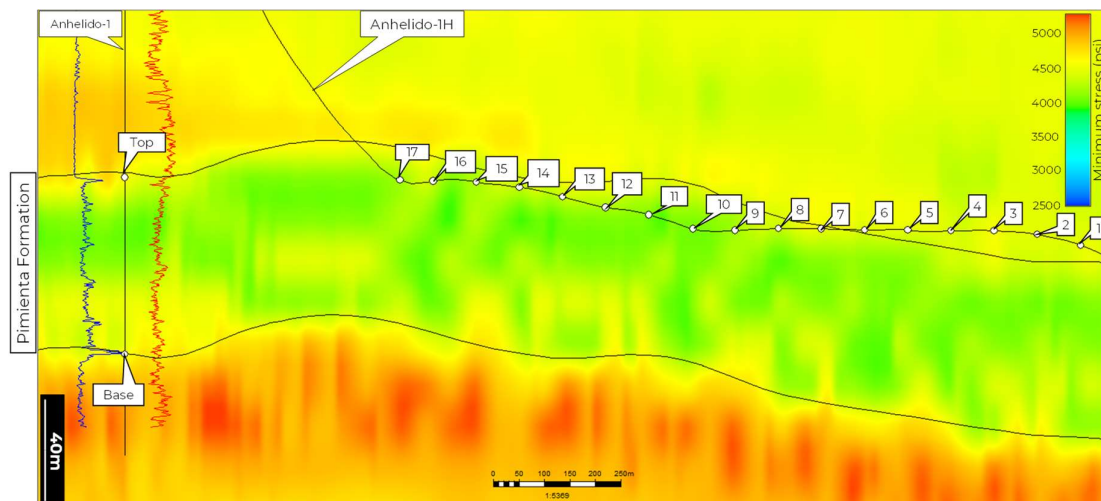


Figure 6.33 Representative arbitrary line across the drilling navigation of minimum principal stress and the hydraulic treating stages at Anhelido-1H

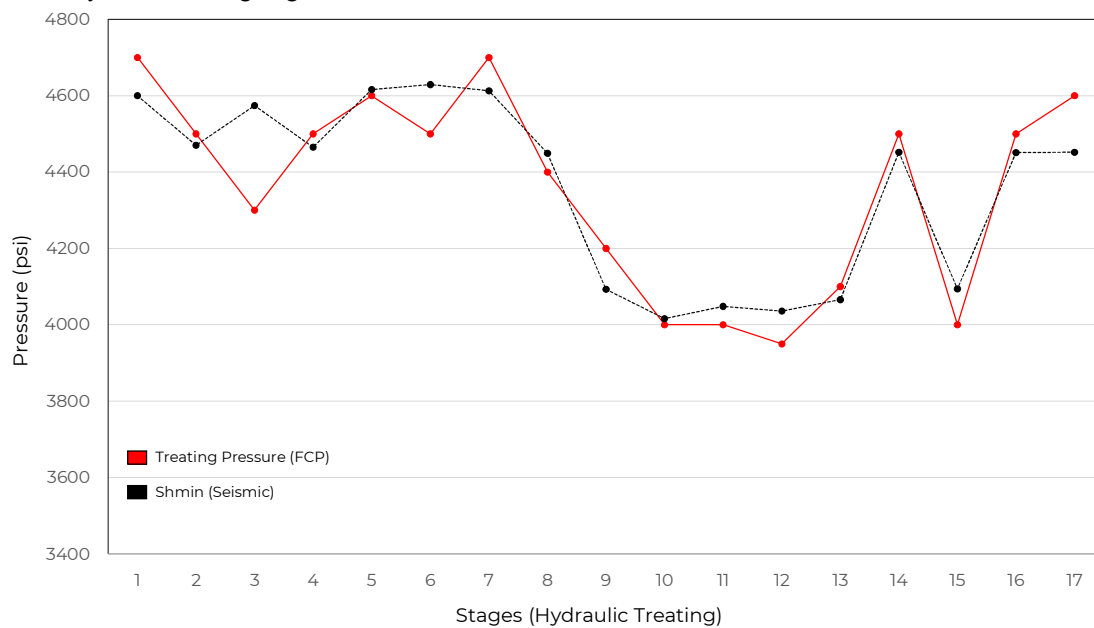


Figure 6.34. Comparison of treating pressure (Fracture Closure Pressure FCP) of the entire length in the horizontal wellbore at Anhelido-1H (17 stages) and the minimum principal stress volume calculated from inverted data.

Anhelido-1H			
Stage	Treating Pressure (Fracture closure pressure FCP psi)	Shmin from Seismic (psi)	Difference (psi)
1	4700	4600	100
2	4500	4470	30
3	4300	4574	274
4	4500	4465	35
5	4600	4616	16
6	4500	4629	129
7	4700	4613	87
8	4400	4449	49
9	4200	4093	107
10	4000	4016	16
11	4000	4048	48
12	3950	4036	86
13	4100	4066	34
14	4500	4452	48
15	4000	4094	94
16	4500	4451	49
17	4600	4452	148
Anhelido-1			
Mini-frac test Pressure		Shmin from Seismic (psi)	Difference (psi)
3916		4051	135

Table 6.8 Comparison from hydraulic treating test (Fracture Closure Pressure FCP) and minimum principal stress from the inverted data along horizontal side of Anhelido-1H and Anhelido-1.

The cross-plot between Young's Modulus and DHRS shows a prevalence of fractures aligned parallel to the maximum stress highlighted in the yellow polygon the stress conditions for

hydraulic fracture propagation in specific directions are plotted in Figure 6.35. By using the data from the static and dynamic Young's modulus from the Triaxial test analysis the average value of 19.5 GPa in Young's Modulus was established as a cut off.

By assigning each dot in green polygon from this scattering plot to the actual inverted volume of Young's Modulus (Figure 6.36A) and DHSR in seismic section we can see that that the reservoir unit is characterised instead by fractures with no preferential azimuth (Figure 6.36B, green area) where the induced hydraulic fractures may propagate in any direction. These conditions are summarized in the methods (section 6.2.4.2) and are based on the DHSR value e.q., (6.22) expecting low values on this property.

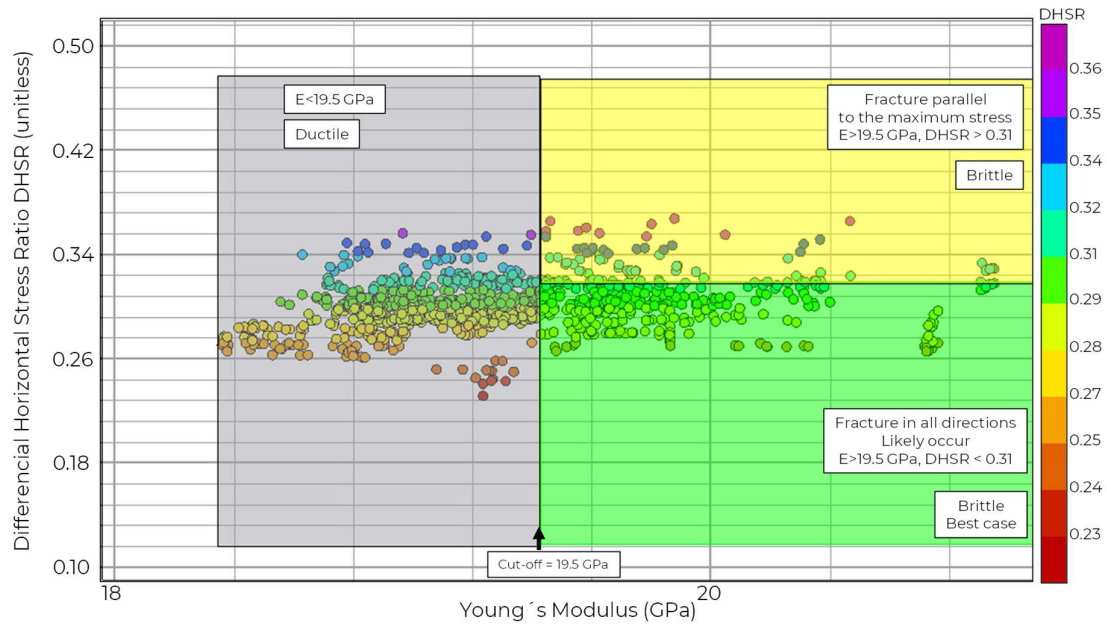


Figure 6.35. Crossplot combination of Young's Modulus and Differential Horizontal Stress Ratio subdivided into three main zones.

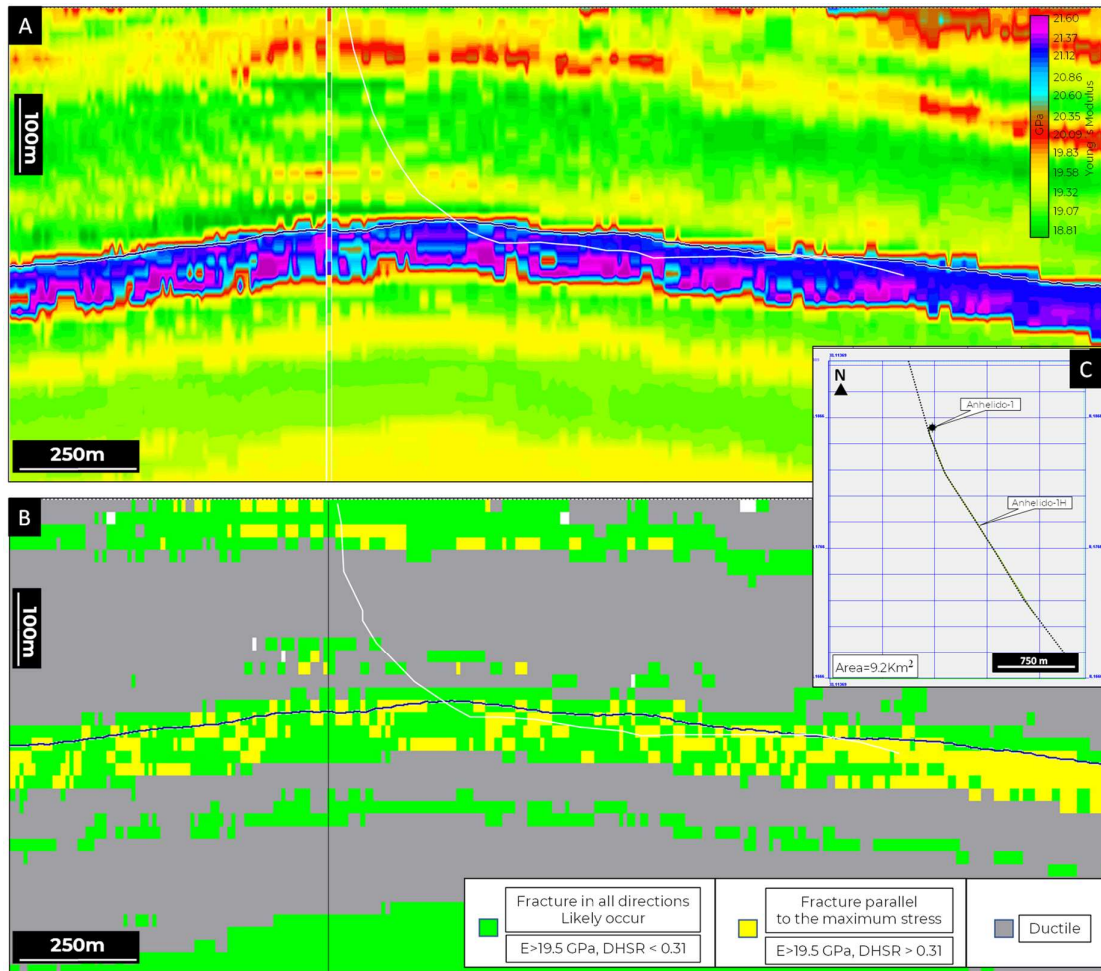


Figure 6.36. A) Inverted Young's Modulus in GPa; B) Crossplot combination of inverted Young's Modulus and Differential Horizontal Stress Ratio (DHSR). Green colour code (Brittle fracture swarm will occur for best case), Yellow colour (Brittle but not the best case), and Gray less brittle worst case.

Finally, integrating the Pressure Transient Analysis (derivative of reservoir pressure) of the 17 stages in the horizontal wellbore Anhelido-1H from reservoir engineering suggest that the flow mechanism responds to a linear flow and then a horizontal flow with a slope of $(\frac{1}{2})$ confirming that this behaviour is characteristic of fractured wells. The flow could be related to the induced fracture itself or the rock matrix according with second derivative pressure where it observed two pressure stabilizations, the first one could be associated to a vertical radial flow and the second one to a horizontal radial flow (Figure 6.37).

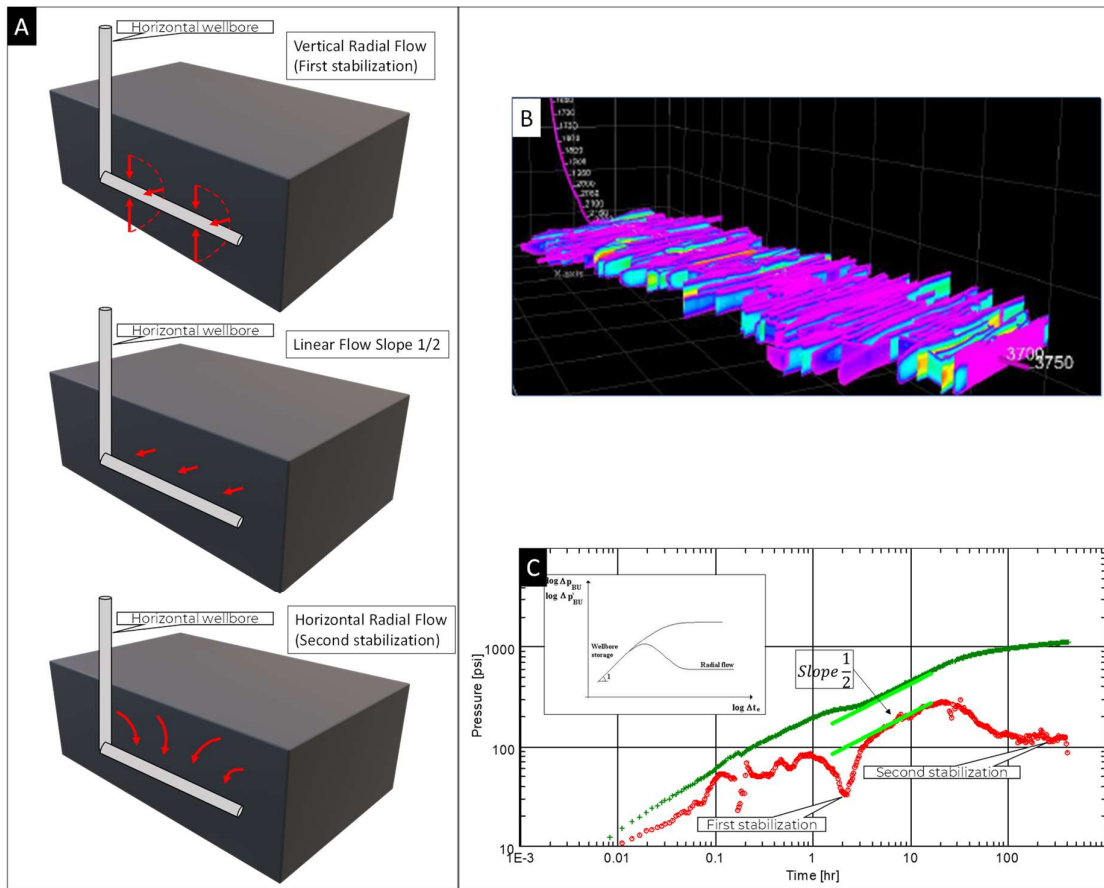


Figure 6.37. Horizontal wellbore storage (Anhelido-1H); A) Flow geometry to and horizontal well and flow regimes (modified from Kazan, 2015); B) Geometry of induced 17 fractures along horizontal wellbore Anhelido-1H; C) Pressure Transient Analysis (derivative of reservoir pressure) with two pressure stabilizations and a slope of $\frac{1}{2}$ of the entire hydraulic treating tests across horizontal well side.

6.4 Discussion

The results of the anisotropic TOC/Brittleness and the stress field around a small area around Anhelido-1 and Amhelido-1H are discussed in this section where some observations have been summarized and described as follows:

6.4.1 TOC calculation in different azimuth sectors based on inverted data

Total organic carbon (TOC) refers to the amount of carbon that is present in the organic matter within a rock or sediment sample and is a weight percent (<https://www.sciencedirect.com/topics/earth-and-planetary-sciences/total-organic-carbon>).

Whilst the TOC is not inherently anisotropic, the distribution of organic matter within the rock or sediment can be highly anisotropic, which can result in anisotropy in TOC for samples measured with some directional component.

TOC values can vary greatly depending on the depositional environment, source of organic matter, and diagenetic history of the rock or sediment (Bohacs et al. 2005). For example, rocks or sediments that were deposited in environments with high organic productivity, such as swamps or lakes, tend to have higher TOC values compared to those deposited in environments with low organic productivity, such as fluvial systems. Additionally, the source of the organic matter, such as algae, plants, or bacteria, also influences the organic carbon content.

The presence of bedding or layering within the rock or sediment can result in anisotropy in organic carbon content, with higher or lower concentrations of organic matter in certain layers (Morgans-Bell et al. 2001). Additionally, the orientation of pores or fractures within the rock or sediment can also result in anisotropy in organic carbon content, as organic matter may preferentially accumulate in certain directions depending on sediment transport directions, or current patterns in the stagnating water bodies, for example.

To summarise, although TOC itself is not itself anisotropic as a single measurement, the distribution of organic matter within rocks or sediments can result in anisotropy in TOC content when sampled in different orientations. This can be due to factors such as layering, pore orientation, and other geological structures. Understanding the anisotropy in TOC content can be important for various applications, such as resource exploration, environmental monitoring, and carbon sequestration.

In my study, the TOC showed values which vary depending on the direction in which it this measure of organic carbon content estimated, as expressed in the results of the azimuthal inversion. The TOC was estimated according to the Equation 6.23 by incorporating the azimuth as an additional variable resulting in the value changes in this property in different directions where a new equation has been proposed to estimate the TOC in different azimuths updating the equation developed by Vernik (2002). The seismically estimated TOC values were computed in four sectors, of which the sector oriented 90° - 180° turned out to have the highest values (Figure 6.20).

Therefore, the seismically parameterized measure of TOC can be seen to be azimuthally dependent.

6.4.2 Correction of elastic properties

The Young's Modulus and Poisson's Ratio were corrected using Triaxial Test data due to the dynamic measurements overestimated this property in some point within Pimienta Formation. The static corrections were used as a constraint for the estimation of Young's Modulus and Poisson Ratio using the Inverted data (e.g., P-S Impedances and Density). This information was used to the calculation of the anisotropic brittleness and the horizontal stresses in the study area.

6.4.3 Anisotropic brittleness ($Brit_V$ and $Brit_H$)

The changes observed in the anisotropic brittleness ($Brit_V$ and $Brit_H$) suggest that the major changes and the highest values were found at sector 2 (90°-180) in both anisotropic modes (VTI and HTI) as shown in Figure 6.27 but the highest values of brittleness at 90° (HTI) are even more evident. The implication of those changes may suggest that Pimienta Formation has intrinsic shale anisotropy due to the lamination parallel to the sedimentation (Qian, KR., Liu, T., Liu, JZ. et al. 2019).

6.4.4 Stress field and DHSR

In this section the Eaton method was used to estimate the pore pressure at Anhelido-1 in order to see the effectiveness of this method within the Pimienta Formation. However, it was considered that the Eaton method was not appropriate for use in this area because it was not designed for highly cemented, deeply buried and uplifted carbonate and shale lithologies that are the main target interval in the study area. Instead of using the Eaton formulation the approach proposed to estimate the correct pore pressure within the Pimienta Formation is that of Atashbari et al (2012). This resulted in a better estimation of the overpressure mechanisms (see section 6.2.4) (Appendix C) in comparison with the Eaton method.

Once the pore pressure was estimated the horizontal stresses were estimated using the inverted data (Young's Modulus and Poisson's Ratio) previously constrained with static information (Triaxial test) (see section 6.2.2) using e.q. (6.18 and 6.19) and the calculation of DHSR using e.q. (6.21).

A cut-off in Young's Modulus was established (19.5 GPa) according with the result of static and dynamic measurements of Young's Modulus this value is the average of the samples used in

triaxial test. Crossplots of Young's Modulus and DHSR were analysed and subdivided in three main polygon zones to assess the best case for hydraulic treating.

According to the cut-off in Young's Modulus, the zone prone to fracture in any direction (best case) has this condition when $E > 19.5 \text{ GPa}$ and $\text{DHSR} < 0.31$. The second zone with $E > 19.5 \text{ GPa}$ and $\text{DHSR} > 0.31$ is characterized by being brittle rock but the fractures may follow a trajectory parallel to the maximum stress (not the best case) Finally the case when $E < 19.5 \text{ GPa}$ is considered to be a mechanically ductile rock (worst case).

Comparison of treating pressures (Fracture Closure Pressure FCP) of the entire length in the horizontal wellbore at Anhelido-1H (17 stages) and the minimum principal stress were established. This comparison exhibits a very good match between minimum stress and the Fracture Closure Pressure FCP.

Finally, the derivative of reservoir pressure of the 17 stages along the horizontal wellbore at Anhelido-1H may suggest that the flow mechanism responds to a linear flow and then a horizontal flow with a slope of $(\frac{1}{2})$ this behaviour is characteristic of fractured wells.

6.4.5 Attribute extraction on TOC and Brittleness

Seismic attributes are quantities (Misra and Mukherjee, 2018) derived from the inverted seismic information that describes the shape or other characteristics of a seismic inverted trace over a specified time interval. The map attributes are important because they enable interpreters to extract more information from inverted seismic information. The seismic attributes addressed in chapter 6 were derived from the inverted traces of TOC and Brittleness for each azimuthal inverted sector, or from an interpreted seismic horizon like in this case using the top and base of Pimienta Formation.

Examples of seismic attributes are wavelet shape, frequency, amplitude, phase, and complex trace information contained in transforms of the real trace. Generally, we use three types of attributes: horizon attributes, interval attributes, and surface attributes.

For his project horizon TOC/Brittleness attributes in four azimuthal sectors are measured relative to an interpreted horizon. These horizon attributes usually measure the properties of TOC and Brittleness estimated from inverted data (P-Impedance, S-Impedance and Density) these properties take value through the horizon that has been mapped on the volumes of TOC (four azimuth sectors) and Brittleness (four azimuth sectors (in VTI/HTI modes) between top and base of the Pimienta Formation which are roughly 80m of thickness. For this case the horizon attribute took the RMS amplitude value at a particular location of the whole horizon (Figure 6.20 and Figure 6.27). We can look at the azimuthal sectors ($0-90^\circ$, $90-180^\circ$, $180-270^\circ$ and $270-360^\circ$) for both properties TOC/Brittleness in two modes (VTI and HTI in all azimuth sectors), and we can also look at the amplitude extraction along the horizon (Top of Pimienta Formation).

These attributes attempt the characterization of the reservoir within Pimienta Formation which will give the best property prediction calibrated with well log data at the well location. For example, Brittleness is a major rock property for effective reservoir stimulation in unconventional reservoirs. Differentiating brittle from ductile rocks is key to performing efficient well location and completion. I calculated a brittleness index (BI) volume from horizon seismic data for the whole azimuthal sectors previously explained, calibrated by well logs, in the Pimienta Formation as well as the total organic carbon (TOC) which is an excellent indicator for the organic richness and the hydrocarbon potential of shale in unconventional reservoirs. However, common methods for TOC estimation have many underlying assumptions and rely on empirical formulas. This topic is addressed in Chapter 3.4. The TOC was estimated for azimuthal ranges using the inverted seismic data.

6.5 Conclusions

The results lead to the following conclusions for this chapter:

1. The application of a new equation for anisotropic TOC was established and a new finding for the estimation of this property shed light on new development which can be used widely in the oil industry to assess unconventional reservoirs.
2. Broadly translated our findings indicate that brittleness calculated in different azimuths may be influenced by the intrinsic shale anisotropy within Pimienta Formation. In addition, these findings provide additional information about importance of the azimuth direction for the estimation of brittleness (VTI/HTI) and ideally, these approaches could be replicated in other projects for its application in unconventional reservoirs development without ignoring their limitation.
3. The stress field was estimated both in the well and in seismic volumes from the inverted data volumes using Young's Modulus and Poisson's Ratio constrained with Triaxial test data (static Young's Modulus). This allowed the calculation of the Differential Horizontal Stress Ratio (DHSR) to assess the best areas prone to fracture in any directions using induced fracture technology (Hydraulic treating tests). These findings provide a potential mechanism for better fracture design in reservoir completion and cost optimization without ignoring the environmental concerns.

7. Discussion

7.1. Introduction

Fracture detection using azimuthal seismic data and fracture modelling in effective media have been applied in the Burgos Basin to assess unconventional reservoirs within the Pimienta Formation and has been described in the previous chapters. In Chapter 1, the scientific literature of geophysical description and the state of the art of this method and the background of the study area were reviewed. Chapter 2 addressed the geological setting and the exploration history of the study area with a focus on the unconventional resources. In Chapter 3 the method and data set preparation were presented and described in detail for their application in this research work. In Chapters 4, 5 and 6, the modelling of fracture in effective media, the use of azimuthal seismic data for the azimuthal AVO analysis and the stress field through inverted seismic data within Pimienta Formation were analysed and discussed.

The following sections will assess the main results of Chapters 4, 5 and 6 to better understand the anisotropy in the shale rock type for the Pimienta Formation. A comparison with other research studies on fracture detection and rock physics characterisation will be made to place the results of this thesis in a broader context.

The aims of this work set out in Chapter 1.5 have been addressed as intended and have led to a more complete investigation of the Pimienta Formation than has been attempted previously, and in so doing, several novel techniques have been developed and employed.

The limitation of the methods developed and applied are discussed below and prior to a discussion of future directions of research for better understanding the anisotropy in shale rock types.

7.2. Summary of key findings

Chapter 4

Contrasting effective media models of fractures models in seismic image computation (e.g., Hudson, Linear-slip) were defined and analysed and yielded different values in anisotropy within Pimienta Formation. The azimuthal seismic image model for each effective medium fracture model exhibits slightly different amplitude distortions with angle and azimuth direction. These distortions were analysed in the Anhelido-1 and Serbal-1 wells. The amplitude changes may potentially be related to the anisotropy of the Pimienta Formation where these distortions were more evident in the far angles of incidence.

Is interesting that the distortions in amplitude were more significant at Serbal-1 compared with Anhelido-1 within the Pimienta Formation. The most compelling explanation for the present set of findings is that the modelling reveals different intensities of anisotropy depending on each fractured model according with the Thomsen's parameters.

The software available routinely in the oil industry, does not handle this type of modeling. In this present work, the development of the ModAz application (Appendix A.4) allowed a very practical modelling tool using well log data in the zone of interest. This application has been developed particularly to better understand the anisotropy of the Pimienta Formation and has been applied for the first time in northern Mexico in this geological formation. However, it can be widely used in other types of reservoirs around the world.

This thesis explores the relationship between the linear slip model and the Penny-shaped crack model by using laboratory measurements and theoretical predictions. The project relies on the experiments conducted by Hsu and Schoenberg (1993) and Hudson (1981, 1997) to test the validity of these models. But additional constraint must be satisfied for the linear slip assumption to hold, which suggests that the model may not be universally applicable. This raises questions

about the limits of the linear slip model and its relationship with other theoretical models, such as the Penny-shaped crack model.

The concept of fracture density and its importance in geophysics for identifying the presence and distribution of fractures in rock formations. In this research work explains how geophysical techniques such as AVO analysis can be used to detect fractures and how azimuthal analysis can provide additional information on fracture orientation. A case study where pre-stack 3D seismic AVAz data is used to detect anisotropy due to the presence of fractures or stress to identify fractured prone sweet spots for appraisal and field development plans.

The process of AVAz modelling and attributes analysis, which involves using Horizontal Transverse Isotropy (HTI) and Linear Slip (LS) models to model subsurface fractured media and understand amplitude in azimuth response due to anisotropy caused by fractures or stress. The fracture density and orientation can be inverted from AVAz information, but the results need to be scaled to realistic crack density due to the band-limited feature of seismic data and phase complexity.

The case study results showed promising indications of anisotropic gradient (B_{ani}) and azimuth in identifying fracture density or stress magnitude in target intervals caused by intrinsic anisotropy, fine stratigraphic layering, fractures induced or stress-induced anisotropy. The near offset Rüger equation results also showed slightly high anisotropy in Serbal-1 and low anisotropy around Anhelido-1 in the vertical part.

The inherent errors in the AVAZ inversion are large and variable, and the fracture intensity attributes from the inversion are not suitable for direct quantitative interpretation but may be used as a qualitative measure of fracture intensity variation for a limited range of incident angles. The limitations of using borehole logs or cores for fracture research and highlights the importance of seismic exploration as a more challenging but valuable and reliable tool for fracture characterization.

Valuable insights into the challenges and limitations of fracture characterization in shale reservoirs and highlights the importance of using advanced techniques such as AVAZ and seismic

exploration to predict the presence of fracture-prone zones and achieve optimum hydrocarbon recovery. The discussion of the effective medium theory also highlights the need to validate its accuracy with practical field data and to consider the geometric features of cracks that may be insignificant for the effective properties.

The existence of anisotropy suggests the presence of intrinsic anisotropy, fine stratigraphic layering, or highly possible due to the presence of fractures or localized stress-induced anisotropy. However, the qualitative nature of the observation suggests that a sonic scanner log should be tested to confirm this assumption but a more challenging method based on seismic exploration is required and it leads to a valuable and reliable tool for fracture characterization.

The use of Backus averaging for elastic properties within the Pimienta Formation case study using well log data allows the estimation of the Thomsen's parameters where the elastic properties of P-Sonic and S-sonic logs were upscaled as an average of a stack of thin layers at a longer wavelength of the seismic data, so possibly the anisotropy obtained with Backus is not significant due to the seismic scale compared to where cracks are considered.

For each effective medium model (e.g., Hudson, Linear-slip), it was found that the values of anisotropy change depending on which effective medium model is applied (penny-shaped cracks or vertical fractures). The azimuthal seismic image model for each effective medium fracture model shows slight amplitude distortions associated with the differences in the values of Thomsen's parameters.

The AVAZ technique is sensitive to the contrast in two Thomsen parameters $\gamma(v)$ and $\delta(v)$ across an interface and is based on the assumption of horizontal transverse isotropy (HTI). However, the real fracture sets in the subsurface do not always conform to this simple configuration, and the inherent errors in AVAZ inversion are large and variable.

The values of anisotropy change depending on which effective medium model is applied, and the azimuthal seismic image model for each effective medium fracture model shows slight amplitude distortions associated with the differences in the values of Thomsen's parameters.

The observations in the amplitude distortions in the azimuthal synthetic gather for the two fracture models are slightly higher in Serbal-1, providing evidence of induced anisotropy within the Pimienta Formation. These findings are consistent with research showing that intrinsic anisotropy in a shale rock type is also evident in the Pimienta Formation.

Chapter 5

In Chapter 5 azimuthal seismic data were used provided by PEMEX company to the application of azimuthal AVO analysis around two areas centred on the horizontal wellbores Anhelido-1 and Serbal-1 for the fracture characterization within the Pimienta Formation. The findings using AVAz demonstrate the possible existence of fracture swarms within the Pimienta Formation in both areas. Across the entire horizontal track of the Anhelido-1H well (Tables 5.5) a difference is apparent in the velocity V_{fast} and V_{slow} . These derived velocities changes may suggest the association of vertical aligned fractures (macro fractures) or stress aligned micro cracks even though the actual stress differs in orientation at the present day as compared with the geological past.

The conditioning of seismic data is an important step before conducting any analysis, as it can significantly impact the accuracy and reliability of the results. In the case of Azimuthal AVO analysis, two common methods for conditioning seismic data are through common offset or common angle gathers with variable azimuth and common azimuth gathers with variable offset-angle within each sector.

The Hampson and Russell package is commonly used for COCA sorting of azimuthal seismic data, which is then followed by the velocity analysis versus azimuth (V_{vaz}) and the analysis of amplitude versus azimuth (AVAz). The azimuthal effects in seismic gathers can be quite significant and can have a significant impact on the results of the analysis. Therefore, it is important to consider and account for these effects in any analysis.

In the study area, velocity variation with azimuth is observed, which can provide important information about the anisotropy and other physical properties of the rocks. The analysis of

velocity versus azimuth can help identify the presence of fractures and other discontinuities, which can have a significant impact on the results of the Azimuthal AVO analysis.

The azimuthal velocity analysis is based on the assumption that the fractures are oriented vertically, and that the velocity anisotropy is due to the preferential orientation of the fractures. By analyzing the velocity field as a function of azimuth, it is possible to estimate the orientation and density of the fractures, as well as the anisotropy parameters such as Thomsen's parameters.

However, it is important to note that the azimuthal AVO and velocity analysis are indirect methods of detecting fractures and anisotropy, and therefore their results should be validated with other techniques, such as well logging or core samples. Additionally, the interpretation of the results should take into account the limitations and assumptions of the methods, as well as the geologic context and other factors that can affect the physical properties of the rocks.

The use of microseismic monitoring in hydraulic fracturing operations has become increasingly common in recent years, as it can provide valuable insights into the behavior of the fracture network and help to improve the efficiency and effectiveness of the fracturing process. In addition, it can also help to reduce the cost of stimulation by optimizing the design of the fracturing treatments and reducing the risk of costly mistakes.

In the case of this project, the information provided by PEMEX/Schlumberger from Well-1 were used to gain insights into the behavior of the fractures created during the induced fracture treatments within the Pimienta Formation. By analyzing the microseismic data from this well-1, it may be possible to identify the orientation and extent of the fractures, as well as any potential issues or challenges that may need to be addressed in future fracturing operations. This information can then be used to optimize the fracturing design and minimize the risk of unwanted fractures or fractures propagating into undesirable formations.

The use of fracture attributes to identify discontinuities and potential faults within the rock formations. The Ant-tracking attribute, in particular, is used to enhance fractures, faults, and discontinuities that may be present in the seismic data.

Chapter 6

In Chapter 6 a new equation was proposed for the estimation of TOC in azimuthal seismic gathers and applied in the study area for the first time within the Pimienta Formation. The equation for brittleness were modified from Rickman et.al., (2009) adding an extra dimension in azimuth for the calculation of anisotropic brittleness. A new approach for the estimation of pore pressure in carbonate/shale rock types was applied. Finally, using the elastic parameters (e.g., Young's Modulus and Poisson's Ratio) derived from triaxial test information within the Pimienta Formation the stress field was estimated and compared with treating data (pressures) along the horizontal side of Anhelido-1H.

The importance of predicting overpressure in unconventional hydrocarbon development to prevent drilling challenges related to high formation pressures. It also mentions that several empirical approaches have been developed to predict overpressure, and most of these approaches are based on shale behaviour where there is a high clay mineral fraction. However, carbonates have a different set of behaviours during burial, and they may have different relationships between porosity and overpressure.

A new method for predicting pore pressure using the compressibility attribute of reservoir rock. The method was developed by Atashbari et al. in 2012 and involves analyzing pore fluid and rock compressibilities to enumerate a list of pore pressure mechanisms. This method can be used to validate other pore pressure prediction methods or to provide a diagnostic analysis of compaction trend.

The horizontal brittleness ($Brit_H$) shows higher values in the middle section of the wellbore, whereas the vertical brittleness ($Brit_v$) shows higher values in the upper and lower sections of the wellbore. The results suggest that the brittleness of the Pimienta Formation in borehole Anhelido-1 is anisotropic, meaning it varies depending on the direction of measurement. The highest values of brittleness are observed when the measurement is made parallel to the

sedimentation direction, which may be related to the intrinsic anisotropy of the shale in this formation. The variation of brittleness along the horizontal section of the wellbore suggests that the formation is also heterogenous along the wellbore.

Based on the comparison between the minimum horizontal stress estimated from the inverted seismic data and the hydraulic treating test results (Fracture Closure Pressure) in each stage at Anhelido-1H, there is a very good match, as shown in Figure 6.33 and Figure 6.34. This suggests that the minimum horizontal stress estimated from the seismic data is a reliable estimate.

The comparison between the minimum horizontal stress estimated from the seismic data and the hydraulic treating test results provides important validation for the seismic inversion method used to estimate the minimum horizontal stress. This can have significant implications for hydraulic fracturing operations in the area, as accurate knowledge of the minimum horizontal stress can help to optimize fracturing design and improve the effectiveness of the stimulation process.

7.3. Comparison with other studies on fracture models and effective medium

The results demonstrated in Chapter 4 match state of the art methods. This is consistent with what has been found in previous studies addressed in Chapter 4 (e.g., Hudson, and linear-slip) section 4.3.4.1 and 4.3.4.4 even though these results go beyond previous reports, it must be pointed out that the results were compared with azimuthal seismic data through azimuthal AVO AVAz.

The results in fracture models within Pimienta Formation are directly consistent with previous findings that have demonstrated that there are amplitude distortions in each effective media fracture models.

These results are addressed in chapter 4 according with the Thomsen's parameters in fracture models and seismic data (Azimuthal AVO analysis).

The importance of understanding the impact of volume fraction kerogen and TOC on the seismic response of organic-rich shale where several researchers have attempted to model the impact of

these parameters on shale's seismic properties using rock physics models, which provide a link between microscopic and macroscopic physical properties of rocks and fluids. The low density of kerogen has a significant impact on the seismic properties of organic shale rocks, as it is one of the three essential components of these rocks, along with void space and rock matrix. To better understand this, impact a DEM theory has been applied in this thesis within Pimienta formation. The understanding the relationship between kerogen fraction, TOC, and seismic properties can help in accurately characterizing organic-rich shale reservoirs, which is crucial for successful exploration and production.

This thesis provides insights into the methods used to quantify the effect of volume fraction kerogen, porosity, and TOC on the seismic properties of organic-rich Pimienta Formation shale. Further research is needed to fully understand the impact of these parameters on seismic data responses and to develop more accurate models for predicting reservoir properties.

The comparison between the elastic stiffness coefficients of the Pimienta Formation and the Bakken shale reported by Vernik and Liu (1997) reveals some interesting findings regarding the impact of kerogen content on the elastic properties of organic-rich shales. The results show that the elastic coefficients of both formations decrease with increasing kerogen content, indicating a significant impact of kerogen on the stiffness of the rock.

This finding is particularly important in the case of the Pimienta Formation, where the mineralogical content is mostly calcite and quartz, which would have a significant impact on high values of elastic coefficients. The inverse relationship between elastic coefficients and kerogen content observed in this study can help to better understand the seismic response of organic-rich shales and improve the accuracy of reservoir characterization.

Moreover, the 3D scatter data presented in Figure 5.20 suggests that there is an inverse relationship between P-wave velocity and TOC, indicating that the presence of organic matter reduces the stiffness of the rock and affects its seismic properties. This is consistent with previous

research in this area and highlights the importance of considering TOC and kerogen content when characterizing shale reservoirs using seismic data.

The findings presented in this thesis project contribute to a better understanding of the impact of organic matter on the elastic properties of shales and provide valuable insights into the seismic response of organic-rich reservoirs. These insights can help to improve the accuracy of reservoir characterization and enable more efficient and effective exploration and production of shale resources.

The use of the Differential effective Method (DEM) theory and Li and Zhang's suggests that the formation has a low aspect ratio, which is confirmed by comparison with experimental data from Walsh et al. (1965). A MATLAB code GUI called DEMmodR1 was developed for the calculation of bulk and dry shear modulus. The results of the modeling show good agreement between well-log data and the prediction log using the DEM theory, with a high correlation between V_p and V_s . Overall, the section demonstrates the application of sophisticated mathematical and computational tools to analyze the physical properties of the Pimienta Formation, providing valuable insights into its characteristics and behavior. Additionally, the VRH bounds for the Pimienta Formation were estimated using XRD data and the 'rppy' geophysical public library for Python, which contains functions for determining rock physics bounds using XRD data.

There are several effective medium approaches, such as the differential effective medium approximation (DEMA), the self-consistent approximation (SCA), and the effective field method (EFM).

The EFM is a powerful tool for estimating the elastic wave velocities in rocks containing cracks. It assumes that the cracks are distributed randomly and that their sizes and orientations are also random. The EFM method calculates the effective elastic moduli by solving the wave equations in a heterogeneous medium consisting of a matrix and randomly oriented cracks. The EFM has been used extensively to estimate the elastic properties of fractured rocks, including shale, sandstone, and carbonates.

Micromechanics and homogenization theories provide a framework for understanding the behavior of rocks as a composite material. The effective field method is a powerful tool for characterizing the behavior of inhomogeneous media, including rocks with complex spatial distributions of inclusions. By determining the effective properties of these media, it is possible to gain insights into their mechanical behavior and accurately predict their interactions with other materials at the macroscopic level.

The results presented in Figures 5.40 to 5.42 show the application of the effective field method to estimate the crack density and anisotropy in the Upper Cretaceous Tamaulipas formation and Pimienta formation. The calculated velocities using the EFM showed differences in velocity between the fast and slow components, indicating the presence of anisotropy in both formations. The angle between the hole axis and the normal to the crack system was also determined, showing a degree angle according to the crack density estimation.

7.4. Azimuthal AVO findings

These basic findings are consistent with research showing that the AVAZ method is capable of demonstrating the presence of possible fractures in the study area and corroborating what was seen by the fractured model (e.g., linear-slip) addressed in Chapter 4.3.2. One of the advantages is that the effectiveness of the AVAZ was demonstrated in an analogy in Well-1, in addition to including other evidence for its demonstration (e.g., microseismic data, structural attributes for fault detection).

The data combination from different sources to investigate the effectiveness of a fracture density attribute in detecting fractures in a reservoir zone is very important. The combination of microseismic, structural attributes and AVAZ data is analysed in the study area of the analogue well-1 to verify the efficacy of the B_{ani} fracture density. The results show an apparent correlation between the preferential direction of possible faults detected by a structural attribute of edge

detection and microseismic data. And the glyphs of fast velocity. The AVAz attribute or fracture density also exhibits a possible fracture swarm within the Pimienta Formation.

The findings in the AVAz analysis suggest the presence of anisotropy within the Pimienta Formation. However, more research is needed to better understand the anisotropy due to the limitation of both core data and geophysical well logs and to verify with greater certainty the presence of fractures or microfractures within the Pimienta Formation.

7.5. Young's Modulus, Poisson's Ratio, brittleness and Stress field

Well-logging measurements were used to calculate the dynamic Young's Modulus, shear modulus, and Poisson's ratio. The dynamic modules were then compared with the static modules measured from triaxial compression tests. The results showed a good correlation between the dynamic and static modules for the same rock sample. However, the static modules were consistently higher than the dynamic modules, indicating that the rock samples were stiffer under static loading conditions. Similar findings were reported by Walsh et al. (1965) and Mavko (2009).

It is important to note that the discrepancy between static and dynamic modules can have significant implications for reservoir characterization and fluid prediction. Static modules are often used in reservoir simulations to predict rock behaviour under in-situ conditions, but if the dynamic modules are significantly different, the predictions may be inaccurate. Therefore, it is essential to understand the factors that contribute to the static-dynamic discrepancy and to carefully consider the appropriate modules to use in reservoir modelling.

The different approaches and attributes proposed by various researchers to predict brittleness indicate the complexity and importance of understanding rock mechanical behaviour. The use of Young's modulus, $\lambda+2\mu/\lambda$, Poisson's ratio, and E_p as indicators of brittleness, along with the analysis of pore geometry, mineralogy, and microstructure, provide valuable information for

characterizing rock formations and predicting their mechanical properties. These attributes can be derived from seismic data and used to identify potential gas-bearing shale reservoirs.

A method developed by Athashbari et.al., (2012) was used to estimate pore pressure within Pimienta Formation. The differential horizontal stress ratio (DHSR) was calculated and combined with elastic properties (e.g., Young's Modulus) in order to establish zones prone to fracture using technology for induced fractures artificially. Finally, the present study confirmed the findings about the minimum stress match very good with the fracture closure pressure FCP from hydraulic treatments.

7.6. General contributions of this research work

This research work contributes to the area of anisotropy (e.g., fracture models) and elastic moduli across the azimuth seismic data (inverted data). Specifically, it introduces a novel approach for the estimation of anisotropic brittleness, and for TOC estimation using azimuthal seismic data (inverted data).

Two main contributions can be highlighted that may help other geoscientists in the search for a better understanding of both the anisotropy of elastic moduli and the estimation of TOC azimuthally.

Main contributions of this work:

1. Azimuthal TOC new equation (modified from Vernik, 2010) that combine different azimuths sectors for TOC calculation through Impedances (e.g., P-Impedance and S-Impedance volumes) from seismic inversion.
2. Brittleness calculated in different directions using the azimuthal seismic sector in both VTI/HTI form by the modification of Rickmann's equation (Rickman, 2009) by using the elastic moduli (e.g., Young's Modulus and Poisson's Ratio).
3. Differential effective method (DEM) theory applied for the first time within Pimienta Formation using MATLAB GUI developed in this thesis (Appendix B.1) (Figure 7.2).

4. Effective field method (EFM) to determine the effective elastic moduli in the Pimienta Formation. The EFM produces explicit equations for the effective characteristics for composites with ellipsoidal inclusions.
5. The implication of kerogen fraction and TOC content in elastic properties within Pimienta Formation.

For such contributions, applications for fracture modeling (e.g., Hudson, and Linear-slip), for the estimation of anisotropic brittleness (anisotropic rock physics), and fluid substitution in shale rock type were developed in MATLAB. Figure 7.1 shows the different application generated and their main use in this work.

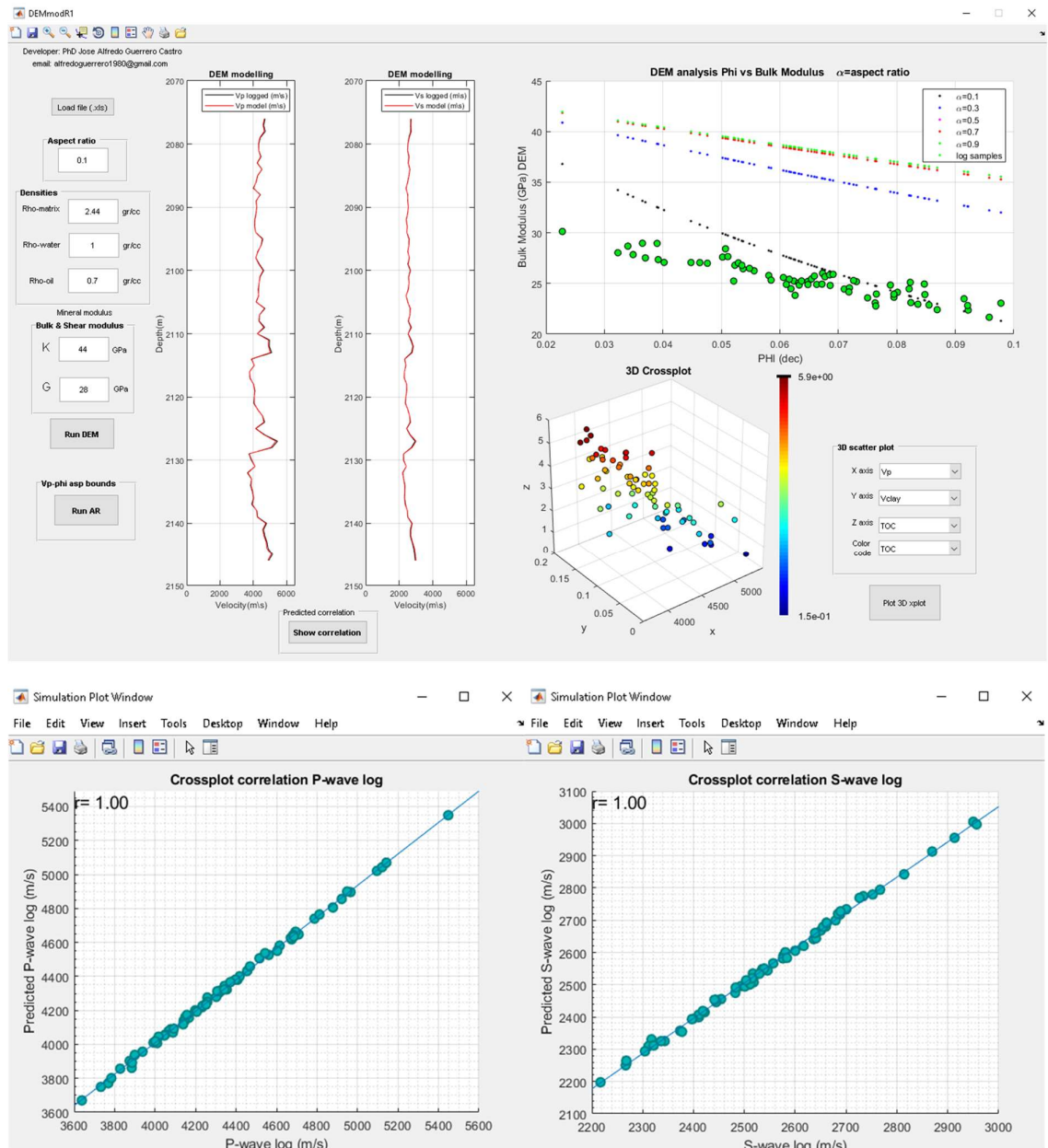


Figure 7.2. Application developed in this research work (DEMmodR1) for Differential Effective Medium

These applications are novel and versatile since in most of the software packages used in the petroleum industry there is no current capability for modeling using the approaches developed in this work. Hence the software is generic and could be used and applied in other reservoirs around the world, taking into account the limitations.

As a final remark, it is important to acknowledge that much of the inspiration and motivation for this work derived from the vision of the future for geophysical research on unconventional reservoirs. In the end, it is this vision that provided the guiding framework. However, it is equally important to understand that many of the results and techniques developed in this work are not limited to the theoretical context but their application. For example, code optimizations on fracture modeling are likely to be relevant to better estimation of effective medium in geosciences applied in the oil industry. The results of the study provide insights into the behavior of anisotropy depending on fracture models for wide application. Similarly, the considerations with respect to elastic properties in core in different direction are likely to be applicable to other studies like this. Thus, even though there were some limitations on this work it motivates this dissertation and may impact or transcend among geosciences community.

7.7 Limitation and step forward

There are at least three potential limitations concerning the results of this study. The first limitation concerns fracture modelling and relates to the consideration of idealized vertical fractures and penny-shaped cracks within the Pimienta Formation. The general limitation in the analysis is the lack of more information to corroborate results with more efficiency. The second potential limitation is the lack of an S-wave log, and this lack of direct calibration may in some way bias the results. However, the S-wave log estimation addressed in Chapter 3 section 3.3 generated using multi-attribute regression is nevertheless considered to be a good approximation.

For azimuth seismic information, one of the main limitations is the angle of incidence, since a better response of the information would be with a broader offset that allows a better understanding of the elastic behavior of the S wave. It is ideal to be able to recover the greatest number of traces on the target of interest which in this case Pimienta Formation. This is key for a more stable S-wave and density included for all azimuths generated in the seismic inversion process.

And finally, the third limitation concerns the limited availability of core data within the Pimienta Formation for laboratory study of the velocity behavior in different azimuths for better anisotropic Young's Modulus and Poisson's Ratio calculation to better constrain the log data.

Despite these limitations, the present study has enhanced our understanding of the relationship of anisotropy of the Pimienta Formation. I hope that the current research will stimulate further investigation of this important area to assess unconventional reservoirs for widely application.

In summary, this research findings contribute to a growing body of geophysical research on unconventional resources. Although the generality of the current results must be established by future research, the present study has provided clear support for the understanding of anisotropy within shale rock type in the important unconventional province of the north of Mexico.

8. Conclusions

8.1. Introduction

In this last chapter key findings and conclusions based on this research work during the DPhil study are presented. Based on the arguments addressed in the discussion chapter the final conclusions are presented below.

This research aimed to identify the anisotropy of shale rock types based on quantitative and qualitative analysis of fracture models in effective media. The goal was to quantify fractures and their implication in these unconventional reservoirs addressing how measurements of anisotropy can be obtained and applied to a characterization of the Pimienta Formation.

By analyzing the fracture models and the AVAz analysis on azimuthal seismic data and rock physics, it can be concluded that the Pimienta Formation presents a significant anisotropy. The results indicate a potential field for the understanding of unconventional resources for better design in hydraulic treatment technology and obtain a better cost benefit for unconventional reservoirs. The second research question concerned the accuracy of the fracture modelling using azimuthal seismic data.

The analysis leads to the following conclusions:

1. The TOC induce anisotropy according with the results in Chapter 6 where amplitude changes on attribute maps of this property estimated from azimuthal seismic inversion.
2. The rock physics analysis developed in section 5.2.3 has demonstrated that the Pimienta Formation fits reasonably good with friable sand line which is a very important finding on rock physics template (RPT) using mineral proportions (XRD).
3. The fractured models addressed in Chapter 4 leads to the understanding of the anisotropy within the Pimienta Formation according with the different values on Thomsen's parameters and provide insights of this phenomena in shale rock type.
4. The AVAz analysis and fluid substitution on shale rock type provide evidence that depending on the fractured model filled with Brine/Hydrocarbon will yield changes on the amplitude behavior as a function of the azimuth.
5. The effective medium DEM theory has been applied in this thesis to calculate the elastic moduli of mixture (oil, gas, kerogen, and water). The use of DEM theory and Li and Zhang's formula for analyzing scatter data in the Pimienta Formation allows to better understand the elastic properties compared with experimental data from other researchers and has been applied for the first time in Pimienta formation

6. Effective field method (EFM) has been used to determine the effective elastic moduli of rock materials with both dry and fluid-filled fractures found in the Pimienta Formation. Crack density and its orientation have been estimated within Tamaulipas and Pimienta formation. The EFM method has limitations and assumptions, such as the assumption of linearity and homogeneity of the material. Therefore, it is important to consider the applicability and accuracy of this method for the specific case of the Pimienta Formation.
7. The anisotropic elastic properties (e.g., Young's Modulus and Poisson's Ratio) in VTI/HTI modes may consider further validation including information of azimuthal velocities from core data.
8. Finally gathering these statements and combining with the stress field the conclusion that can be drawn is that the fracture closure pressure from hydraulic treatments confirm a reasonable match with the stress field (minimum stress) obtained in this research work using the inverted data.

8.2. Fracture models

The analysed fractured models described in Chapter 4 helped to understand in greater detail the inherent anisotropy of the Pimienta Formation, the findings suggest an effective way to evaluate this characteristic through the use of information from geophysical well logs and modelling. Thus, depending on the type of fracture model, the anisotropic and elastic characteristics of the formation can be better understood which is a key factor for the reservoir evaluation in unconventional resources.

One of the advantages is that these models are based on the theory of the effective medium and put into practice with well logging through modelling. All the models responded to anisotropy, which somehow corroborates the possible presence of fractures, since with hydraulic stimulation it was possible to connect fractures induced by this technology to the rock matrix.

8.3. Differential effective medium (DEM)

In this thesis, the relationship between bulk modulus and porosity in scatter data analysis inside the Pimienta Formation has been examined. This thesis also analyzes the Differential Effective Medium theory (DEM) concept.

Calculating the bulk and shear moduli of composite media's elastic characteristics was possible thanks to the differential effective medium theory. According to this idea, the model is "constructed" as a solid background medium containing ellipsoidal inclusions. To avoid going against Kuster and Toksoz's (1974) premises, the inclusions are added in an interactive way. The elastic moduli of mixtures (oil, gas, kerogen, and water) and organic shales have been calculated using the effective medium DEM theory given by Kuster and Toksöz (1974).

8.4. Effective field method (EFM)

The Effective Field Method (EFM) has been used to estimate elastic properties within Tamaulipas and Pimienta formations, which addresses the challenging problem of estimating the effective physical qualities of heterogeneous random media and emphasizes the significance of using self-consistent schemes to solve the homogenization problem.

8.5. Brittleness calculated in different directions

For brittleness, one more variable was added to the Rickman equation, which is estimated in 4 azimuthal sectors, this is important, given that it has been applied for the first time in the Pimienta Formation. The different brittleness attributes extracted from the Pimienta Formation exhibit changes in this property values where the highest occur in the azimuth (90° 180°) in both VTI/HTI corresponding to sector 2.

This implies that the brittleness values change as it moves in a clockwise direction from north and corroborates the anisotropy of the Pimienta Formation previously modeled in Chapter 4 with the different fracture models.

8.6 TOC calculated in different azimuth direction

Finally, an extra dimension into the standard TOC equation developed by Vernik (2010) were added and a novel method for estimating this variable was developed through the use of seismic inversion volumes from Chapter 6, including Impedance P and Impedance S and geochemical information of the study area.

In the attributes extracted from this property in the Pimienta formation, changes were also noted across the azimuth where the highest TOC value was found again in sector 2 (90°-180°). However, more information on wells with geochemical data is needed for a more accurate estimation and more research in this area needs to be applied in future studies for better understanding.

Reference

- Abu-Mahfouz, I. S., Cartwright, J., Idiz, E., Hooker, J. N., & Robinson, S. A. (2020). Silica diagenesis promotes early primary hydrocarbon migration. *Geology*, 48(5), 483–487. <https://doi.org/10.1130/G47023.1>
- Al-Fahmi, M. M., Hooker, J. N., Al-Mojel, A. S., & Cartwright, J. A. (2020). New scaling of fractures in a giant carbonate platform from outcrops and subsurface. *Journal of Structural Geology*, 140, 104142. <https://doi.org/10.1016/j.jsg.2020.104142>
- Al-Fahmi, M. M., Ozkaya, S. I., & Cartwright, J. A. (2018a). New insights on fracture roughness and wall mismatch in carbonate reservoir rocks. *Geosphere*, 14(4), 1851–1859. <https://doi.org/10.1130/GES01612.1>
- Al-Fahmi, M. M., Ozkaya, S. I., & Cartwright, J. A. (2018b). New insights on fracture roughness and wall mismatch in carbonate reservoir rocks. *Geosphere*, 14(4), 1851–1859. <https://doi.org/10.1130/GES01612.1>
- Alford, R. M. (1986). Shear data in the presence of azimuthal anisotropy: Dilley, Texas. *SEG Technical Program Expanded Abstracts 1986*, 476–479. <https://doi.org/10.1190/1.1893036>
- Alzahabi, Ahmed & Alqahtani, Ghazi & Soliman, Mohamed & Bateman, Richard & Asquith, George & Vadapalli, Ravi. (2015). Fracturability Index is a Mineralogical Index: A New Approach for Fracturing Decision. <https://doi.org/10.2118/178033-MS>
- Annual Energy Outlook 2011, Report DOE/EIA-0383(2011)*. (2011). EIA.
- Bai, J.-Y., Yue, C.-Q., Liang, Y.-Q., Song, Z.-X., Ling, S., Zhang, Y., & Wu, W. (2013). Variable aspect ratio method in the Xu–White model for shear-wave velocity estimation. *Journal of Geophysics and Engineering*, 10(3), 035008. <https://doi.org/10.1088/1742-2132/10/3/035008>
- Bakulin, A., Grechka, V., & Tsvankin, I. (2000). Estimation of fracture parameters from reflection seismic data—Part I: HTI model due to a single fracture set. *GEOPHYSICS*, 65(6), 1788–1802. <https://doi.org/10.1190/1.1444863>
- Bakulin, A., Grechka, V., & Tsvankin, I. (2000). Estimation of fracture parameters from reflection seismic data—Part III: Fractured models with monoclinic symmetry. In *GEOPHYSICS* (Vol. 65, Issue 6, pp. 1818–1830). Society of Exploration Geophysicists. <https://doi.org/10.1190/1.1444865>

- Barati Ghahfarokhi, R., & Alhubail, M. M. (2020). *Unconventional hydrocarbon resources: Techniques for reservoir engineering analysis*. Wiley-American Geophysical Union.
- Beard, T. (2011). *Fracture Design in Horizontal Shale Wells –Data Gathering to Implementation*.
- Berdichevskii, M. N., Dmitriev, V. I., & Keller, G. V. (2002). *Magnetotellurics in the context of theory of ill-posed problems*. Society of Exploration Geophysicists.
- Biot, M. A. (1956). Theory of Propagation of Elastic Waves in a Fluid-Saturated Porous Solid. I. Low-Frequency Range. *The Journal of the Acoustical Society of America*, 28(2), 168–178. <https://doi.org/10.1121/1.1908239>
- Blangy, J. P. (1994). AVO in transversely Isotropic media—An overview. *GEOPHYSICS*, 59(5), 775–781. <https://doi.org/10.1190/1.1443635>
- Boadu, F. K., & Long, L. T. (1996). Effects of fractures on seismic-wave velocity and attenuation. *Geophysical Journal International*, 127(1), 86–110. <https://doi.org/10.1111/j.1365-246X.1996.tb01537.x>
- Bortfeld, R. (1961). APPROXIMATIONS TO THE REFLECTION AND TRANSMISSION COEFFICIENTS OF PLANE LONGITUDINAL AND TRANSVERSE WAVES*. *Geophysical Prospecting*, 9(4), 485–502. <https://doi.org/10.1111/j.1365-2478.1961.tb01670.x>
- Brahma, J., & Sircar, A. (2014). Estimation of the Effect of Anisotropy on Young's Moduli and Poisson's Ratios of Sedimentary Rocks Using Core Samples in Western and Central Part of Tripura, India. In *International Journal of Geosciences* (Vol. 05, Issue 02, pp. 184–195). Scientific Research Publishing, Inc. <https://doi.org/10.4236/ijg.2014.52020>.
- Brown, A. R. (2005). Pitfalls in 3D seismic interpretation: Keynote presentation at the 11th Annual 3-D Seismic Symposium, Denver. *The Leading Edge*, 24(7), 716–717. <https://doi.org/10.1190/1.1993265>
- Brown, R. J. S., & Korringa, J. (1975). ON THE DEPENDENCE OF THE ELASTIC PROPERTIES OF A POROUS ROCK ON THE COMPRESSIBILITY OF THE PORE FLUID. *GEOPHYSICS*, 40(4), 608–616. <https://doi.org/10.1190/1.1440551>

- Caeiro, M. H., Al Kobaisi, A., & Neves, F. (2017). Seismic Reservoir Characterisation for Horizontal Well Planning: A Field Case Study of an Unconventional Upper Jurassic Reservoir Onshore UAE. *Day 2 Tue, November 14, 2017*, D021S053R005. <https://doi.org/10.2118/188700-MS>
- Canning*, A., & Malkin, A. (2015). Obstacles in the analysis of azimuth information from prestack seismic data. *SEG Technical Program Expanded Abstracts 2015*, 427–431. <https://doi.org/10.1190/segam2015-5897229.1>
- Cary, P. W. (1999). Common-offset-vector gathers: An alternative to cross-spreads for wide-azimuth 3-D surveys. *SEG Technical Program Expanded Abstracts 1999*, 1496–1499. <https://doi.org/10.1190/1.1820804>
- Castagna, J. P., Batzle, M. L., & Eastwood, R. L. (1985). Relationships between compressional-wave and shear-wave velocities in clastic silicate rocks. *GEOPHYSICS*, 50(4), 571–581. <https://doi.org/10.1190/1.1441933>
- Castagna, J. P., & Swan, H. W. (1997). Principles of AVO crossplotting. *The Leading Edge*, 16(4), 337–344. <https://doi.org/10.1190/1.1437626>
- Chapman, M. (2003). Frequency-dependent anisotropy due to meso-scale fractures in the presence of equant porosity: *Frequency-dependent anisotropy due to meso-scale fractures. Geophysical Prospecting*, 51(5), 369–379. <https://doi.org/10.1046/j.1365-2478.2003.00384.x>
- Charsky, A., & Herron, S. (n.d.). *Accurate, Direct Total Organic Carbon (TOC) Log from a New Advanced Geochemical Spectroscopy Tool: Comparison with Conventional Approaches for TOC Estimation. 2013.*
- Chen, T., Hafez, M., Moustafa, A., Al-Hasan, H., Basha, F., & Evdokimova, M. (2018). Seismic anisotropy analysis using prestack azimuthal inversion for fracture prediction: A case study in Kuwait. *SEG Technical Program Expanded Abstracts 2018*, 3246–3250. <https://doi.org/10.1190/segam2018-2996836.1>
- Cheng, C. H. (1993). Crack models for a transversely isotropic medium. *Journal of Geophysical Research: Solid Earth*, 98(B1), 675–684. <https://doi.org/10.1029/92JB02118>
- Chopra, S., & Marfurt, K. J. (2005). Seismic attributes—A historical perspective. *GEOPHYSICS*, 70(5), 3SO-28SO. <https://doi.org/10.1190/1.2098670>

- Circular* (Circular). (1985). [Circular].
- Cilli, P. A., & Chapman, M. (2020). The Power-Law Relation Between Inclusion Aspect Ratio and Porosity: Implications for Electrical and Elastic Modeling. In *Journal of Geophysical Research: Solid Earth* (Vol. 125, Issue 5). American Geophysical Union (AGU). <https://doi.org/10.1029/2019jb019187>
- CISAN-UNAM, Parraguez Kobek, M. L., Ugarte, A., & Campero Aguilar, G. (2015). Shale Gas in the United States: Transforming Energy Security in the Twenty-first Century. *Norteamérica*, 10(1), 7–38. <https://doi.org/10.20999/nam.2015.a001>
- Crampin, S. (1981). A review of wave motion in anisotropic and cracked elastic-media. *Wave Motion*, 3(4), 343–391. [https://doi.org/10.1016/0165-2125\(81\)90026-3](https://doi.org/10.1016/0165-2125(81)90026-3)
- Crampin, S. (2007). Quantitative Seismology: Theory and Methods, Volumes I and II by Keiiti Aki and Paul G. Richards. W. H. Freeman and Co., San Francisco. Price: £41·40. *Geological Journal*, 16(1), 90–90. <https://doi.org/10.1002/gj.3350160110>
- Cui, X., Krebs, E. S., Lines, L., & Peng, S. (2018). *Seismic Forward Modeling of Fractures and Fractured Medium Inversion* (1st ed. 2018). Springer Singapore: Imprint: Springer. <https://doi.org/10.1007/978-981-10-3584-5>
- Dake, L. P. (1983). *Developments in Petroleum Science, 8: Fundamentals of Reservoir Engineering*. Elsevier. <http://public.eblib.com/choice/publicfullrecord.aspx?p=404173>
- David, E. C., Brantut, N., Schubnel, A., & Zimmerman, R. W. (2012). Sliding crack model for nonlinearity and hysteresis in the uniaxial stress–strain curve of rock. *International Journal of Rock Mechanics and Mining Sciences*, 52, 9–17. <https://doi.org/10.1016/j.ijrmms.2012.02.001>
- Dawe, R. A., & Zhang, Y. (1997). Kinetics of calcium carbonate scaling using observations from glass micromodels. *Journal of Petroleum Science and Engineering*, 18(3–4), 179–187. [https://doi.org/10.1016/S0920-4105\(97\)00017-X](https://doi.org/10.1016/S0920-4105(97)00017-X)
- Dembicki, H. (2017). *Practical petroleum geochemistry for exploration and production*. Elsevier.
- Deng, X., Liu, C., Guo, Z., Liu, X., & Liu, Y. (2019). Rock physical inversion and quantitative seismic interpretation for the Longmaxi shale gas reservoir. *Journal of Geophysics and Engineering*, 16(3), 652–665. <https://doi.org/10.1093/jge/gxz035>

- DeVault, B., Davis, T. L., Tsvankin, I., Verm, R., & Hilterman, F. (2002). Multicomponent AVO analysis, Vacuum field, New Mexico. *GEOPHYSICS*, 67(3), 701–710. <https://doi.org/10.1190/1.1484513>
- Dvorkin, J., & Nur, A. (1996). Elasticity of high-porosity sandstones: Theory for two North Sea data sets. *GEOPHYSICS*, 61(5), 1363–1370. <https://doi.org/10.1190/1.1444059>
- Eshelby, J. D. (1957). The determination of the elastic field of an ellipsoidal inclusion, and related problems. *Proceedings of the Royal Society of London. Series A. Mathematical and Physical Sciences*, 241(1226), 376–396. <https://doi.org/10.1098/rspa.1957.0133>
- Far, M. E., de Figueiredo, J. J. S., Stewart, R. R., Castagna, J. P., Han, D.-H., & Dyaour, N. (2014). Measurements of seismic anisotropy and fracture compliances in synthetic fractured media. *Geophysical Journal International*, 197(3), 1845–1857. <https://doi.org/10.1093/gji/ggu101>
- Fitz-Díaz, E., Lawton, T. F., Juárez-Arriaga, E., & Chávez-Cabello, G. (2018). The Cretaceous-Paleogene Mexican orogen: Structure, basin development, magmatism and tectonics. *Earth-Science Reviews*, 183, 56–84. <https://doi.org/10.1016/j.earscirev.2017.03.002>
- Flemings, P. (2021). *A Concise Guide to Geopressure: Origin, Prediction, and Applications*. Cambridge: Cambridge University Press. [doi:10.1017/9781107326309](https://doi.org/10.1017/9781107326309)
- Flotte, N., Martinez-Reyes, J., Rangin, C., Le Pichon, X., Husson, L., & Tardy, M. (2008). The Rio Bravo fault, a major late Oligocene left-lateral shear zone. *Bulletin de La Société Géologique de France*, 179(2), 147–160. <https://doi.org/10.2113/gssgfbull.179.2.147>
- Focke, J. W., & Munn, D. (1987). Cementation Exponents in Middle Eastern Carbonate Reservoirs. *SPE Formation Evaluation*, 2(02), 155–167. <https://doi.org/10.2118/13735-PA>
- Fossen, H. (2016). *Structural geology* (Second edition). Cambridge University Press.
- G. C. P. K. (1981). [No title found]. *Geological Magazine*, 118(2), 208–208. <https://doi.org/10.1017/S0016756800034439>
- Gale, J. F. W., Laubach, S. E., Olson, J. E., Eichhülle, P., & Fall, A. (2014). Natural Fractures in shale: A review and new observations. *AAPG Bulletin*, 98(11), 2165–2216. <https://doi.org/10.1306/08121413151>

- Gardner, G. H. F., Gardner, L. W., & Gregory, A. R. (1974). FORMATION VELOCITY AND DENSITY—THE DIAGNOSTIC BASICS FOR STRATIGRAPHIC TRAPS. *GEOPHYSICS*, 39(6), 770–780. <https://doi.org/10.1190/1.1440465>
- Ge, Z., Pan, S., Li, J., Zhang, D., & Luo, H. (2020). Estimation of weak anisotropy parameters and fracture density of asymmetric fractures in monoclinic medium. *Journal of Geophysics and Engineering*, 17(6), 1049–1064. <https://doi.org/10.1093/jge/gxaa063>
- Geng, Z., Chen, M., Jin, Y., Yang, S., Yi, Z., Fang, X., & Du, X. (2016). Experimental study of brittleness anisotropy of shale in triaxial compression. In *Journal of Natural Gas Science and Engineering* (Vol. 36, pp. 510–518). Elsevier BV. <https://doi.org/10.1016/j.jngse.2016.10.059>
- Goldhammer, R. K. (1999). Mesozoic sequence stratigraphy and paleogeographic evolution of northeast Mexico. In *Special Paper 340: Mesozoic sedimentary and tectonic history of north-central Mexico* (Vol. 340, pp. 1–58). Geological Society of America. <https://doi.org/10.1130/0-8137-2340-X.1>
- Gonzalez G., Q. (n.d.). *Geology of the Source Rocks of Mexico*. 1991.
- Gray, D. (2008). *Fracture Detection Using 3D Seismic Azimuthal AVO*. 33(2008), 03.
- Gray, D., & Head, K. (2000). Fracture detection in the Manderson Field: A 3D AVAZ case history. *SEG Technical Program Expanded Abstracts 2000*, 1413–1416. <https://doi.org/10.1190/1.1815667>
- Gray, D., Roberts, G., & Head, K. (2002). Recent advances in determination of fracture strike and crack density from *P*-wave seismic data. *The Leading Edge*, 21(3), 280–285. <https://doi.org/10.1190/1.1463778>
- Gray, D., & Todorovic-Marinic, D. (n.d.). *Fracture Detection using 3D Seismic*.
- Gray, F. D., & Head, K. J. (2000). Using 3D Seismic To Identify Spatially Variant Fracture Orientation in the Manderson Field. *All Days*, SPE-60296-MS. <https://doi.org/10.2118/60296-MS>
- Grechka, V., Pech, A., & Tsvankin, I. (2005). Parameter estimation in orthorhombic media using multicomponent wide-azimuth reflection data. *GEOPHYSICS*, 70(2), D1–D8. <https://doi.org/10.1190/1.1897026>

- Grechka, V., & Wapenaar, K. (Eds.). (2014). *Encyclopedia of Exploration Geophysics*. Society of Exploration Geophysicists. <https://doi.org/10.1190/1.9781560803027>
- Guéguen, Y., & Kachanov, M. (2011). Effective Elastic Properties of Cracked Rocks—An Overview. In Y. M. Leroy & F. K. Lehner (Eds.), *Mechanics of Crustal Rocks* (Vol. 533, pp. 73–125). Springer Vienna. https://doi.org/10.1007/978-3-7091-0939-7_3
- Guo, Z., & Liu, X. (2018). Seismic rock physics characterization of anisotropic shale—A Longmaxi Shale case study. *Journal of Geophysics and Engineering*, 15(2), 512–526. <https://doi.org/10.1088/1742-2140/aa9fe1>
- Guzev, M., Riabokon, E., Turbakov, M., Kozhevnikov, E., & Poplygin, V. (2020). Modelling of the Dynamic Young's Modulus of a Sedimentary Rock Subjected to Nonstationary Loading. In *Energies* (Vol. 13, Issue 23, p. 6461). MDPI AG. <https://doi.org/10.3390/en13236461>
- Hall, S. A., & Kendall, J. (2003a). Fracture characterization at Valhall: Application of P-wave amplitude variation with offset and azimuth (AVOA) analysis to a 3D ocean-bottom data set. *GEOPHYSICS*, 68(4), 1150–1160. <https://doi.org/10.1190/1.1598107>
- Hall, S. A., & Kendall, J. (2003b). Fracture characterization at Valhall: Application of P-wave amplitude variation with offset and azimuth (AVOA) analysis to a 3D ocean-bottom data set. *GEOPHYSICS*, 68(4), 1150–1160. <https://doi.org/10.1190/1.1598107>
- Han, D., & Batzle, M. L. (2004). Gassmann's equation and fluid-saturation effects on seismic velocities. *GEOPHYSICS*, 69(2), 398–405. <https://doi.org/10.1190/1.1707059>
- Han, D., Nur, A., & Morgan, D. (1986). Effects of porosity and clay content on wave velocities in sandstones. *GEOPHYSICS*, 51(11), 2093–2107. <https://doi.org/10.1190/1.1442062>
- Healy, D., Rizzo, R. E., Cornwell, D. G., Farrell, N. J. C., Watkins, H., Timms, N. E., Gomez-Rivas, E., & Smith, M. (2017). FracPaQ: A MATLAB™ toolbox for the quantification of fracture patterns. *Journal of Structural Geology*, 95, 1–16. <https://doi.org/10.1016/j.jsg.2016.12.003>
- Helen S. Morgans-Bell, Angela L. Coe, Stephen P. Hesselbo, Hugh C. Jenkyns, Graham P. Weedon, John E. A. Marshall, Richard V. Tyson, Carolyn J. Williams; Integrated stratigraphy of the Kimmeridge Clay Formation (Upper Jurassic) based on exposures and boreholes in south Dorset,

UK. *Geological Magazine* 2001;; 138 (5): 511–539.

doi: <https://doi.org/10.1017/S0016756801005738>

Herawati, I., Winardhi, S., & Priyono, A. (2015). *Estimation of anisotropy parameters in organic-rich shale: Rock physics forward modeling approach*. 060011. <https://doi.org/10.1063/1.4930691>

Holt, R. M., Nes, O.-M., Stenebraten, J. F., & Fjaer, E. (2012). *Static Vs. Dynamic Behavior of Shale*. ARMA-2012-542.

Hooker, J. N., Abu-Mahfouz, I. S., Meng, Q., & Cartwright, J. (2019). Fractures in mudrocks: Advances in constraining timing and understanding mechanisms. *Journal of Structural Geology*, 125, 166–173. <https://doi.org/10.1016/j.jsg.2018.04.020>

Hooker, J. N., Gale, J. F. W., Gomez, L. A., Laubach, S. E., Marrett, R., & Reed, R. M. (2009). Aperture-size scaling variations in a low-strain opening-mode fracture set, Cozzette Sandstone, Colorado. *Journal of Structural Geology*, 31(7), 707–718. <https://doi.org/10.1016/j.jsg.2009.04.001>

Horbury, A. D., Hall, S., Francisco, G.-P., Dioniso, R.-F., Armando, R.-F., Patricia, O.-G., Martín, M.-M., & Guillermo, Q.-R. (2003). Tectonic Sequence Stratigraphy of the Western Margin of the Gulf of Mexico in the Late Mesozoic and Cenozoic Less Passive than Previously Imagined. In C. Bartolini, R. T. Buffler, & J. F. Blickwede, *The Circum-Gulf of Mexico and the Caribbean_{Hydrocarbon Habitats, Basin Formation and Plate Tectonics}*. American Association of Petroleum Geologists. <https://doi.org/10.1306/M79877C8>

Hudson, J. A. (1980). Overall properties of a cracked solid. *Mathematical Proceedings of the Cambridge Philosophical Society*, 88(2), 371–384. <https://doi.org/10.1017/S0305004100057674>

Hudson, J. A. (1981a). Wave speeds and attenuation of elastic waves in material containing cracks. *Geophysical Journal International*, 64(1), 133–150. <https://doi.org/10.1111/j.1365-246X.1981.tb02662.x>

Hudson, J. A. (1981b). Wave speeds and attenuation of elastic waves in material containing cracks. *Geophysical Journal International*, 64(1), 133–150. <https://doi.org/10.1111/j.1365-246X.1981.tb02662.x>

- Ilya, T., & Grechka, V. (2006). *Developments in seismic anisotropy: Treating realistic subsurface models in imaging and fracture detection. Special Edition*, 42–45.
- Imran, Q. S., Siddiqui, N. A., Latiff, A. H. A., Bashir, Y., Khan, M., Qureshi, K., Al-Masgari, A. A.-S., Ahmed, N., & Jamil, M. (2021). Automated Fault Detection and Extraction under Gas Chimneys Using Hybrid Discontinuity Attributes. *Applied Sciences*, 11(16), 7218. <https://doi.org/10.3390/app11167218>
- Jarvie, D. M., Hill, R. J., Ruble, T. E., & Pollastro, R. M. (2007). Unconventional shale-gas systems: The Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment. *AAPG Bulletin*, 91(4), 475–499. <https://doi.org/10.1306/12190606068>
- Javier Hernández-Mendoza, J., DeAngelo, M. V., Wawrzyniec, T. F., & Hentz, T. F. (2008). Major structural elements of the Miocene section, Burgos Basin, northeastern Mexico. *AAPG Bulletin*, 92(11), 1479–1499. <https://doi.org/10.1306/07020808020>
- Jilek, P. (2002). Converted PS -wave Reflection Coefficients in Weakly Anisotropic Media. *Pure and Applied Geophysics*, 159(7–8), 1527–1562. <https://doi.org/10.1007/s00024-002-8696-9>
- John B. Curtis¹. (2002). Fractured shale-gas systems. *AAPG Bulletin*, 86. <https://doi.org/10.1306/61EEDDBE-173E-11D7-8645000102C1865D>
- Jones, T. A., & Detwiler, R. L. (2016). Fracture sealing by mineral precipitation: The role of small-scale mineral heterogeneity: MINERAL PRECIPITATION IN FRACTURES. *Geophysical Research Letters*, 43(14), 7564–7571. <https://doi.org/10.1002/2016GL069598>
- Jones, T. A., & Detwiler, R. L. (2019). Mineral Precipitation in Fractures: Using the Level-Set Method to Quantify the Role of Mineral Heterogeneity on Transport Properties. *Water Resources Research*, 55(5), 4186–4206. <https://doi.org/10.1029/2018WR024287>
- Juhlin, C. (n.d.). *Reflection seismic methods applied to locating fracture zones in crystalline rock*. 1998.
- Julie Shemeta and Paul Anderson, (2010), "It's a matter of size: Magnitude and moment estimates for microseismic data," *The Leading Edge* 29: 296-302. <https://doi.org/10.1190/1.3353726>.
- Kanaun, S., & Levin, V. (2013). Effective Field Method in the Theory of Heterogeneous Media. In *Effective Properties of Heterogeneous Materials* (pp. 199–282). Springer Netherlands. https://doi.org/10.1007/978-94-007-5715-8_3

- Kevin M. Bohacs, George J. Grabowski, Jr., Alan R. Carroll, Paul J. Mankiewicz, Kimberlee J. Miskell-Gerhardt, Jon R. Schwalbach, Mary Beth Wegner, J.A. (Toni) Simo, 2005. "Production, Destruction, and Dilution—The Many Paths to Source-Rock Development", *The Deposition of Organic-Carbon-Rich Sediments: Models, Mechanisms, and Consequences*, Nicholas B. Harris
- Khadeeva, Y., & Vernik, L. (2013). Rock physics model for unconventional shales. *SEG Technical Program Expanded Abstracts 2013*, 2757–2761. <https://doi.org/10.1190/segam2013-0986.1>
- Khaled, A., and Gray, F. (2017) AVA and AVAZ of 3D pre-stack seismic data in AltamontBluebell field
- Khalid, P., Qureshi, J., Din, Z. U., Ullah, S., & Sami, J. (2019). Effect of Kerogen and TOC on Seismic Characterization of Lower Cretaceous Shale Gas Plays in Lower Indus Basin, Pakistan. In *Journal of the Geological Society of India* (Vol. 94, Issue 3, pp. 319–327). Springer Science and Business Media LLC. <https://doi.org/10.1007/s12594-019-1312-8>
- Kliangglom, P., Sulaeman, E., Tunsoonthornjit, W., Tongpet, T., Loboontert, P., Utitsan, S., & Lynn, H. (2011). Azimuthal Anisotropy Evaluation Based on Wide Azimuth 3D Data for Fracture Analysis in Chonnabot Carbonate Reservoir. *All Days*, IPTC-15332-MS. <https://doi.org/10.2523/IPTC-15332-MS>
- Knott, C. G. (1899). III. *Reflexion and refraction of elastic waves, with seismological applications*. *The London, Edinburgh, and Dublin Philosophical Magazine and Journal of Science*, 48(290), 64–97. <https://doi.org/10.1080/14786449908621305>
- Koltanovsky, L., Korolev, A., Rossiyskaya, E., & Smirnov, K. (2017). Enhancing confidence in fracture prediction through advanced seismic data processing and analysis techniques. *First Break*, 35(2149). <https://doi.org/10.3997/1365-2397.2017004>
- Kumar, D. (2013). Applying Backus averaging for deriving seismic anisotropy of a long-wavelength equivalent medium from well-log data. *Journal of Geophysics and Engineering*, 10(5), 055001. <https://doi.org/10.1088/1742-2132/10/5/055001>
- Lee, Y.-J., & Morse, J. W. (1999). Calcite precipitation in synthetic veins: Implications for the time and fluid volume necessary for vein filling. *Chemical Geology*, 156(1–4), 151–170. [https://doi.org/10.1016/S0009-2541\(98\)00183-1](https://doi.org/10.1016/S0009-2541(98)00183-1)

- Lev Vernik (2), Charles Landis (3). (1996). Elastic Anisotropy of Source Rocks: Implications for Hydrocarbon Generation and Primary Migration. *AAPG Bulletin*, 80. <https://doi.org/10.1306/64ED8836-1724-11D7-8645000102C1865D>
- Levin, V., Markov, M., & Kanaun, S. (2004). Effective field method for seismic properties of cracked rocks. In *Journal of Geophysical Research: Solid Earth* (Vol. 109, Issue B8). American Geophysical Union (AGU). <https://doi.org/10.1029/2003jb002795>
- Li, H., & Zhang, J. (2011). Elastic moduli of dry rocks containing spheroidal pores based on differential effective medium theory. In *Journal of Applied Geophysics* (Vol. 75, Issue 4, pp. 671–678). Elsevier BV. <https://doi.org/10.1016/j.jappgeo.2011.09.012>
- Li, L., Guo, Y., Zhang, G., Pan, X., Zhang, J., & Lin, Y. (2022). Seismic characterization of in situ stress in orthorhombic shale reservoirs using anisotropic extended elastic impedance inversion. In *GEOPHYSICS* (Vol. 87, Issue 6, pp. M259–M274). Society of Exploration Geophysicists. <https://doi.org/10.1190/geo2021-0807.1>
- Lines, L. R., & Newrick, R. T. (2004). *Fundamentals of Geophysical Interpretation*. Society of Exploration Geophysicists. <https://doi.org/10.1190/1.9781560801726>
- Liu, E., Chapman, M., Li, X., Queen, J. H., & Lynn, H. (2006). Kinematic and dynamic anisotropy: Implication of seismic fracture characterizations. *SEG Technical Program Expanded Abstracts 2006*, 135–139. <https://doi.org/10.1190/1.2369772>
- Liu, E., Johns, M., Burnett, W., Zhang, J., Wu, X., Skeith, G., & Zelewski, G. (2016). Effects of overburden and thin layers on fracture-induced azimuthal AVO response. *SEG Technical Program Expanded Abstracts 2016*, 347–351. <https://doi.org/10.1190/segam2016-13962042.1>
- Lynn, H. B., & Thomsen, L. A. (1990). Reflection shear-wave data collected near the principal axes of azimuthal anisotropy. *GEOPHYSICS*, 55(2), 147–156. <https://doi.org/10.1190/1.1442821>
- Ma, H.-D., White, R. E., & Hu, T.-Y. (2010). Wavelet estimation by matching well-log, VSP, and surface-seismic data. *Applied Geophysics*, 7(4), 384–391. <https://doi.org/10.1007/s11770-010-0264-y>
- Margheriti, L., Baccheschi, P., & Park, J. (2021). Seismic Anisotropy. In *Encyclopedia of Geology* (pp. 622–635). Elsevier. <https://doi.org/10.1016/B978-0-08-102908-4.00156-9>

- Marrett, R., Laubach, S. E., & Olson, J. E. (2007). Anisotropy and beyond: Geologic perspectives on geophysical prospecting for natural fractures. *The Leading Edge*, 26(9), 1106–1111. <https://doi.org/10.1190/1.2780778>
- Maultzsch, S., Horne, S., Archer, S., & Burkhardt, H. (2003). Effects of an anisotropic overburden on azimuthal amplitude analysis in horizontal transverse isotropic media: Effects of anisotropic overburden on P-wave amplitudes. *Geophysical Prospecting*, 51(1), 61–74. <https://doi.org/10.1046/j.1365-2478.2003.00354.x>
- Mavko, G., Mukerji, T., & Dvorkin, J. (2009). *The Rock Physics Handbook: Tools for Seismic Analysis of Porous Media* (2nd ed.). Cambridge University Press. <https://doi.org/10.1017/CBO9780511626753>
- McGarr, A., & Gay, N. C. (1978). State of Stress in the Earth's Crust. *Annual Review of Earth and Planetary Sciences*, 6(1), 405–436. <https://doi.org/10.1146/annurev.ca.06.050178.002201>
- Meng, F., Wong, L. N. Y., & Zhou, H. (2021). Rock brittleness indices and their applications to different fields of rock engineering: A review. In *Journal of Rock Mechanics and Geotechnical Engineering* (Vol. 13, Issue 1, pp. 221–247). Elsevier BV. <https://doi.org/10.1016/j.jrmge.2020.06.008>
- Morse, J. W., & Mackenzie, F. T. (1990). *Geochemistry of sedimentary carbonates*. Elsevier; Distributors for the U.S. and Canada, Elsevier Science Pub. Co.
- Mukerji, T., & Mavko, G. (1994). Pore fluid effects on seismic velocity in anisotropic rocks. *GEOPHYSICS*, 59(2), 233–244. <https://doi.org/10.1190/1.1443585>
- Nelson, R. A. (2007). *Geologic analysis of naturally fractured reservoirs*. Knovel.
- Neuzil, C. E. (1994). How permeable are clays and shales? *Water Resources Research*, 30(2), 145–150. <https://doi.org/10.1029/93WR02930>
- Olson, J. E., Laubach, S. E., & Lander, R. H. (2009). Natural fracture characterization in tight gas sandstones: Integrating mechanics and diagenesis. *AAPG Bulletin*, 93(11), 1535–1549. <https://doi.org/10.1306/08110909100>
- Oportunidades de los no Convencionales*. (2018). Comision Nacional de Hidrocarburos CNH.

- Ore, T. M. (2020). *A Machine Learning and Data-Driven Prediction and Inversion of Reservoir Brittleness from Geophysical Logs and Seismic Signals: A Case Study in Southwest Pennsylvania, Central Appalachian Basin* [MS, West Virginia University Libraries]. <https://doi.org/10.33915/etd.7714>
- Ouenes, A. (2014). *Integrated Fracture Modeling Using Seismic Data, Prism Seismic. 2014.*
- Pacht, J. A., Sheriff, R. E., & Perkins, B. F. (Eds.). (1996). *Stratigraphic Analysis Utilizing Advanced Geophysical, Wireline and Borehole Technology for Petroleum Exploration and Production: 17th Annual.* SOCIETY OF ECONOMIC PALEONTOLOGISTS AND MINERALOGISTS. <https://doi.org/10.5724/gcs.96.17>
- Pedersen, S. I., Randen, T., Sonneland, L., & Steen, Ø. (2002). Automatic fault extraction using artificial ants. *SEG Technical Program Expanded Abstracts 2002*, 512–515. <https://doi.org/10.1190/1.1817297>
- Pérez, M. A., Gibson, R. L., & Toksöz, M. N. (1999). Detection of fracture orientation using azimuthal variation of *P*-wave AVO responses. *GEOPHYSICS*, 64(4), 1253–1265. <https://doi.org/10.1190/1.1444632>
- Pérez, G., (1993). "Geologic evolution of the Burgos Basin, northeastern Mexico." Diss., Rice University. <https://hdl.handle.net/1911/16657>.
- Pervukhina, M., & Rasolofosaon, P. N. J. (2017). Compaction trend versus seismic anisotropy in shaly formations: Compaction trend versus seismic anisotropy. *Geophysical Prospecting*, 65(5), 1351–1365. <https://doi.org/10.1111/1365-2478.12486>
- Price, N. J., & Rhodes, F. H. T. (2015). *Fault and joint development in brittle and semi-brittle rock.*
- Q. R. Passey (2), S. Creaney (3), J. (1990a). A Practical Model for Organic Richness from Porosity and Resistivity Logs. *AAPG Bulletin*, 74. <https://doi.org/10.1306/0C9B25C9-1710-11D7-8645000102C1865D>
- Q. R. Passey (2), S. Creaney (3), J. (1990b). A Practical Model for Organic Richness from Porosity and Resistivity Logs. *AAPG Bulletin*, 74. <https://doi.org/10.1306/0C9B25C9-1710-11D7-8645000102C1865D>

- Qian, K.-R., Liu, T., Liu, J.-Z., Liu, X.-W., He, Z.-L., & Jiang, D.-J. (2020). Construction of a novel brittleness index equation and analysis of anisotropic brittleness characteristics for unconventional shale formations. *Petroleum Science*, 17(1), 70–85. <https://doi.org/10.1007/s12182-019-00372-6>
- Rahmani, F., Emami Niri, M. & Jozanikohan, G. Construction of 2D and 3D rock physics templates for quantitative prediction of physical properties of a carbonate reservoir in SW of Iran. *J Petrol Explor Prod Technol* **13**, 449–470 (2023). <https://doi.org/10.1007/s13202-022-01560-8>
- Reagan, M. T., Moridis, G. J., Keen, N. D., & Johnson, J. N. (2015). Numerical simulation of the environmental impact of hydraulic fracturing of tight/shale gas reservoirs on near-surface groundwater: Background, base cases, shallow reservoirs, short-term gas, and water transport. *Water Resources Research*, 51(4), 2543–2573. <https://doi.org/10.1002/2014WR016086>
- Richard T. Buffler, Dale S. Sawyer. (1985). Distribution of Crust and Early History, Gulf of Mexico Basin: ABSTRACT. *AAPG Bulletin*, 69. <https://doi.org/10.1306/AD462C9F-16F7-11D7-8645000102C1865D>
- Rickman, R., Mullen, M. J., Petre, J. E., Grieser, W. V., & Kundert, D. (2008). A Practical Use of Shale Petrophysics for Stimulation Design Optimization: All Shale Plays Are Not Clones of the Barnett Shale. *All Days*, SPE-115258-MS. <https://doi.org/10.2118/115258-MS>
- Rider, M. H. (2006). *The geological interpretation of well logs* (2. ed., rev.reprinted). Rider-French Consulting.
- Rock Fractures and Fluid Flow: Contemporary Understanding and Applications* (p. 2309). (1996). National Academies Press. <https://doi.org/10.17226/2309>
- Rüger, A. (1997). *P* -wave reflection coefficients for transversely isotropic models with vertical and horizontal axis of symmetry. *GEOPHYSICS*, 62(3), 713–722. <https://doi.org/10.1190/1.1444181>
- Rüger, A. (2002). *Reflection Coefficients and Azimuthal AVO Analysis in Anisotropic Media*. Society of Exploration Geophysicists. <https://doi.org/10.1190/1.9781560801764>
- Russell, B. H., & Hampson, D. (n.d.). *An Inversion Primer*. 31(2006).

- Russell, B. H., Hampson, D. P., & Lines, L. R. (2004). A case study in the local estimation of shear-wave logs. *SEG Technical Program Expanded Abstracts 2004*, 390–393. <https://doi.org/10.1190/1.1851278>
- Rutherford, S. R., & Williams, R. H. (1989). Amplitude-versus-offset variations in gas sands. *GEOPHYSICS*, 54(6), 680–688. <https://doi.org/10.1190/1.1442696>
- Ryan-Grigor, S. (1998). Empirical relationships between anellipticity and V_p/V_s in shales: Potential applications to AVO studies and anisotropic seismic processing. *SEG Technical Program Expanded Abstracts 1998*, 208–211. <https://doi.org/10.1190/1.1820372>
- Sarkar, Sudipta, Toksöz, M. N., Burns, & R., D. (n.d.). *Fluid Flow Modeling in Fractures*. 2004. <http://hdl.handle.net/1721.1/68616>
- Sava, D. (2004). Quantitative Data Integration for Fracture Characterization Using Statistical Rock Physics. Thesis Stanford University
- Sayers, C. M. (2007). Introduction to this special section: Fractures. *The Leading Edge*, 26(9), 1102–1105. <https://doi.org/10.1190/1.2780777>
- Sayers, C. M. (2013). The effect of kerogen on the elastic anisotropy of organic-rich shales. In *GEOPHYSICS* (Vol. 78, Issue 2, pp. D65–D74). Society of Exploration Geophysicists. <https://doi.org/10.1190/geo2012-0309.1>
- Sayers, C. M., Guo, S., & Silva, J. (2015). Sensitivity of the elastic anisotropy and seismic reflection amplitude of the Eagle Ford Shale to the presence of kerogen: Anisotropy of the Eagle Ford Shale. *Geophysical Prospecting*, 63(1), 151–165. <https://doi.org/10.1111/1365-2478.12153>
- Sayers, C. M., & Kachanov, M. (1991). A simple technique for finding effective elastic constants of cracked solids for arbitrary crack orientation statistics. *International Journal of Solids and Structures*, 27(6), 671–680. [https://doi.org/10.1016/0020-7683\(91\)90027-D](https://doi.org/10.1016/0020-7683(91)90027-D)
- Scheeder, G., Weniger, P., & Blumenberg, M. (2020). Geochemical implications from direct Rock-Eval pyrolysis of petroleum. *Organic Geochemistry*, 146, 104051. <https://doi.org/10.1016/j.orggeochem.2020.104051>
- Schoenberg, M. (1980). Elastic wave behavior across linear slip interfaces. *The Journal of the Acoustical Society of America*, 68(5), 1516–1521. <https://doi.org/10.1121/1.385077>

- Schoenberg, M. (1983). REFLECTION OF ELASTIC WAVES FROM PERIODICALLY STRATIFIED MEDIA WITH INTERFACIAL SLIP*. *Geophysical Prospecting*, 31(2), 265–292. <https://doi.org/10.1111/j.1365-2478.1983.tb01054.x>
- Shang, E.-C., Li, Q., & Gao, T. F. (2002). *Theoretical and Computational Acoustics 2001*. WORLD SCIENTIFIC. <https://doi.org/10.1142/4979>
- Sharma, R. K., & Chopra, S. (2012). New attribute for determination of lithology and brittleness. *SEG Technical Program Expanded Abstracts 2012*, 1–5. <https://doi.org/10.1190/segam2012-1389.1>
- Shen, Y., Meng, M., Liu, T., Ge, H., & Zhang, Y. (2017). Impact of Petrophysical Properties on Hydraulic Fracturing and Development in Tight Volcanic Gas Reservoirs. *Geofluids*, 2017, 1–13. <https://doi.org/10.1155/2017/5235140>
- Sheriff, R. E. (2002). *Encyclopedic Dictionary of Applied Geophysics* (Fourth). Society of Exploration Geophysicists. <https://doi.org/10.1190/1.9781560802969>
- Sheriff, R. E., & Geldart, L. P. (1995). *Exploration Seismology* (2nd ed.). Cambridge University Press. <https://doi.org/10.1017/CBO9781139168359>
- Skoyles, D., DeWildt, J., Erickson, J., Innemee, H., & Monk, D. (1999). Azimuthally dependent amplitude vs. offset in 3D seismic: An automated statistical measurement and case study. In *SEG Technical Program Expanded Abstracts 1999*. SEG Technical Program Expanded Abstracts 1999. Society of Exploration Geophysicists. <https://doi.org/10.1190/1.1821141>
- Smith, R. L., & McGarrity, J. P. (2001). Cracking the fractures—Seismic anisotropy in an offshore reservoir. *The Leading Edge*, 20(1), 18–26. <https://doi.org/10.1190/1.1438870>
- Sone, H., & Zoback, M. D. (2013). Mechanical properties of shale-gas reservoir rocks — Part 1: Static and dynamic elastic properties and anisotropy. *GEOPHYSICS*, 78(5), D381–D392. <https://doi.org/10.1190/geo2013-0050.1>
- Spence, G. H., Couples, G. D., Bevan, T. G., Aguilera, R., Cosgrove, J. W., Daniel, J.-M., & Redfern, J. (2014). Advances in the study of naturally fractured hydrocarbon reservoirs: A broad integrated interdisciplinary applied topic. *Geological Society, London, Special Publications*, 374(1), 1–22. <https://doi.org/10.1144/SP374.19>

- Stevens, S. H., & Moodhe, K. D. (2015). Evaluation of Mexico's Shale Oil and Gas Potential. *Day 1 Wed, November 18, 2015*, D011S001R004. <https://doi.org/10.2118/177139-MS>
- Tang, X. M., Zheng, Y., & Patterson, D. (2007). Processing array acoustic-logging data to image near-borehole geologic structures. *GEOPHYSICS*, 72(2), E87–E97. <https://doi.org/10.1190/1.2435083>
- Thomsen, L. (1986). Weak elastic anisotropy. *GEOPHYSICS*, 51(10), 1954–1966. <https://doi.org/10.1190/1.1442051>
- Thomsen, L. (1995). Elastic anisotropy due to aligned cracks in porous rock1. *Geophysical Prospecting*, 43(6), 805–829. <https://doi.org/10.1111/j.1365-2478.1995.tb00282.x>
- Thomsen, L. (2002). *Understanding Seismic Anisotropy in Exploration and Exploitation*. Society of Exploration Geophysicists and European Association of Geoscientists and Engineers. <https://doi.org/10.1190/1.9781560801986>
- Tiab, D., & Donaldson, E. C. (2012). *Petrophysics: Theory and practice of measuring reservoir rock and fluid transport properties* (3rd ed). Gulf Professional Pub.
- Tod, S., Taylor, B., Johnston, R., & Allen, T. (2007). Fracture prediction from wide-azimuth land seismic data in SE Algeria. *The Leading Edge*, 26(9), 1154–1160. <https://doi.org/10.1190/1.2780786>
- Treadgold, G., Sicking, C., Sublette, V., & Hoover, G. (2008). Azimuthal processing for fracture prediction and image improvement. *SEG Technical Program Expanded Abstracts 2008*, 988–992. <https://doi.org/10.1190/1.3063803>
- Trumbo, A., & Rich, J. P. (2013). Azimuthal variations in attributes for induced fracture detection in the Barnett Shale. *Interpretation*, 1(2), SB51–SB59. <https://doi.org/10.1190/INT-2013-0027.1>
- Tsvankin, I. (1997). Reflection moveout and parameter estimation for horizontal transverse isotropy. *GEOPHYSICS*, 62(2), 614–629. <https://doi.org/10.1190/1.1444170>
- Tsvankin, I., Gaiser, J., Grechka, V., van der Baan, M., & Thomsen, L. (2010). Seismic anisotropy in exploration and reservoir characterization: An overview. *GEOPHYSICS*, 75(5), 75A15-75A29. <https://doi.org/10.1190/1.3481775>

- Tsvankin, I., & Grechka, V. (2011). *Seismology of Azimuthally Anisotropic Media and Seismic Fracture Characterization*. Society of Exploration Geophysicists. <https://doi.org/10.1190/1.9781560802839>
- Unconventional Hydrocarbon Resources: Techniques for Reservoir Engineering*. (n.d.).
- van der Baan, M., & Pham, D.-T. (2008). Robust wavelet estimation and blind deconvolution of noisy surface seismics. *GEOPHYSICS*, 73(5), V37–V46. <https://doi.org/10.1190/1.2965028>
- Vermeer, G. (2003). Responses to wide-azimuth acquisition special section. *The Leading Edge*, 22(1), 26–30. <https://doi.org/10.1190/1.1523756>
- Vermeer, G. J. O. (2002). *3-D Seismic Survey Design*. Society of Exploration Geophysicists. <https://doi.org/10.1190/1.9781560801757>
- Vermeer, G. J. O. (2007). Reciprocal offset-vector tiles in various acquisition geometries. *SEG Technical Program Expanded Abstracts 2007*, 61–65. <https://doi.org/10.1190/1.2792382>
- Vernik, L., & Kachanov, M. (2010). Modeling elastic properties of siliciclastic rocks. *GEOPHYSICS*, 75(6), E171–E182. <https://doi.org/10.1190/1.3494031>
- Vernik, L., Liu, X., & Nur, A. (1994). Effect of kerogen on velocity anisotropy in source rocks. *SEG Technical Program Expanded Abstracts 1994*, 323–326. <https://doi.org/10.1190/1.1932086>
- Vernik, L., & Nur, A. (1992). Ultrasonic velocity and anisotropy of hydrocarbon source rocks. *GEOPHYSICS*, 57(5), 727–735. <https://doi.org/10.1190/1.1443286>
- Vlastos, S., Liu, E., Main, I. G., Schoenberg, M., Narteau, C., Li, X. Y., & Maillot, B. (2006). Dual simulations of fluid flow and seismic wave propagation in a fractured network: effects of pore pressure on seismic signature. In *Geophysical Journal International* (Vol. 166, Issue 2, pp. 825–838). Oxford University Press (OUP). <https://doi.org/10.1111/j.1365-246x.2006.03060.x>
- Walsh, J. B. (1965). The effect of cracks on the compressibility of rock. In *Journal of Geophysical Research* (Vol. 70, Issue 2, pp. 381–389). American Geophysical Union (AGU). <https://doi.org/10.1029/jz070i002p00381>
- Wang, F. P., & Gale, J. F. W. (n.d.). *Screening Criteria for Shale-Gas Systems*. 59, 779–794.
- Warpinski, N. R. (2009). Integrating Microseismic Monitoring With Well Completions, Reservoir Behavior, and Rock Mechanics. *All Days*, SPE-125239-MS. <https://doi.org/10.2118/125239-MS>

- Watt, J. P., Davies, G. F., & O'Connell, R. J. (1976). The elastic properties of composite materials. *Reviews of Geophysics*, 14(4), 541. <https://doi.org/10.1029/RG014i004p00541>
- Wennberg, O. P. (n.d.). *Fracture aperture in reservoir rocks: Examples from the Shetland Chalk in the Gullfaks Field*.
- Wennberg, O. P., Casini, G., Jonoud, S., & Peacock, D. C. P. (2016). The characteristics of open fractures in carbonate reservoirs and their impact on fluid flow: A discussion. *Petroleum Geoscience*, 22(1), 91–104. <https://doi.org/10.1144/petgeo2015-003>
- White, R. E., & Simm, R. (2003). Tutorial: Good practice in well ties. *First Break*, 21(10). <https://doi.org/10.3997/1365-2397.21.10.25640>
- William E. Galloway (2). (1989). Genetic Stratigraphic Sequences in Basin Analysis II: Application to Northwest Gulf of Mexico Cenozoic Basin. *AAPG Bulletin*, 73. <https://doi.org/10.1306/703C9AFA-1707-11D7-8645000102C1865D>
- Williams, R. M., Pascual-Cebrian, E., Paton, G., & Gutmanis, J. C. (2016). Evaluating the Gap between Seismic-scale and Well-scale Observations of Structure—A North Sea Case Study. *78th EAGE Conference and Exhibition 2016*, 1–5. <https://doi.org/10.3997/2214-4609.201601167>
- Xiao, J. (2017). Shale Formation: What Do We Learn about Fracture Conductivity Damage? *Oil & Gas Research*, 03(01). <https://doi.org/10.4172/2472-0518.1000127>
- Xu, X., & Tsvankin, I. (2008). Moveout-based geometrical-spreading correction for PS-waves in layered anisotropic media. *Journal of Geophysics and Engineering*, 5(2), 195–202. <https://doi.org/10.1088/1742-2132/5/2/006>
- Xu, X., Tsvankin, I., & Pech, A. (2005). Geometrical spreading of P-waves in horizontally layered, azimuthally anisotropic media. *GEOPHYSICS*, 70(5), D43–D53. <https://doi.org/10.1190/1.2052467>
- Yexin Liu. (2014). AVAZ and VVAZ practical analysis to estimate anisotropic properties. *Search and Discovery Article*, #90224(2014).
- Zhang, L. (2019). *Well production performance analysis for shale gas reservoirs*.
- Zhang, Y., & Dawe, R. (1998). The kinetics of calcite precipitation from a high salinity water. *Applied Geochemistry*, 13(2), 177–184. [https://doi.org/10.1016/S0883-2927\(97\)00061-9](https://doi.org/10.1016/S0883-2927(97)00061-9)

- Zhang, Jun & Ai, Chi & Li, Yuwei & Zeng, Jia & Qiu, Dezhi. (2017). Brittleness evaluation index based on energy variation in the whole process of rock failure. *Yanshilixue Yu Gongcheng Xuebao/Chinese Journal of Rock Mechanics and Engineering*. 36. 10.13722/j.cnki.jrme.2016.0839.
- Zhao, G., Jin, Z., Ding, W., Liu, G., Yun, J., Wang, R., & Wang, G. (2022). Developmental characteristics and formational stages of natural fractures in the Wufeng - Longmaxi Formation in the Sangzhi Block, Hunan Province, China: Insights from fracture cements and fluid inclusions studies. *Journal of Petroleum Science and Engineering*, 208, 109407. <https://doi.org/10.1016/j.petrol.2021.109407>
- Zhu, Y., & Tsvankin, I. (2006). Plane-wave propagation in attenuative transversely isotropic media. *GEOPHYSICS*, 71(2), T17–T30. <https://doi.org/10.1190/1.2187792>
- Zoback, M. D. (2007). *Reservoir Geomechanics*. Cambridge University Press. <https://doi.org/10.1017/CBO9780511586477>

Appendix A

A.1 CRACKEDMED

Program (MATLAB source code “CRACKEDMED” based on The Hudson model to estimate anisotropic parameters.

```
function pushbutton1_Callback(hObject, eventdata, handles)

% hObject    handle to pushbutton1 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    structure with handles and user data (see GUIDATA)

%global Vp Vs Rho e Asp phie g C11a C13a C33a C44a C66a C12t Eh2 Gh2 Dh2

Vp = str2double(char(get(handles.edit1,'String')));
Vs = str2double(char(get(handles.edit2,'String')));
Rho = str2double(char(get(handles.edit3,'String')));
e = str2double(char(get(handles.edit4,'String')));
Asp = str2double(char(get(handles.edit5,'String')));
phie = str2double(char(get(handles.edit6,'String')));

g =(Vs/Vp)^2;
v = ((Vp.^2 - 2.*Vs.^2) ./ (Vp.^2 - Vs.^2))./2 ;
vf = (1 - v/2)

a1 = g*(1-2*g);
a2 =(3 - 2*g);
a3 =(1 - g);
b1 = 8*e;
```

```

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%DRY
CASE%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

% output Thomsen's Parameters

E = ((8/3)*e)*-1
D = E*(1 + (g*(1-2*g)/(3 - 2*g)*(1 - g)))
G = (8*e)/(3*(3 - 2*g))*-1;

set(handles.edit7,'String',E);
set(handles.edit8,'String',G);
set(handles.edit9,'String',D);

```

A.2 FRACKMED

Program (MATLAB source code “FRACKMED” based on The Linear-slip model to estimate anisotropic parameters.

```

function pushbutton1_Callback(hObject, eventdata, handles)

% hObject    handle to pushbutton1 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    structure with handles and user data (see GUIDATA)

global C11 C33 C44 C66 C13 E G D ccyt

syms C11 C12 C13 S33 C21 C22 C23 C31 C32 C32 C44 C55 C66

Vp = str2double(char(get(handles.edit1,'String')));
Vs = str2double(char(get(handles.edit2,'String')));
Rho = str2double(char(get(handles.edit3,'String')));
e = str2double(char(get(handles.edit4,'String')));

```

```
Asp = str2double(char(get(handles.edit5,'String')));
```

```
v = ((Vp.^2 - 2.*Vs.^2) ./ ((Vp.^2 - Vs.^2)).*2 )
```

```
vf = 1 -v/2
```

```
g = (Vs/Vp)^2
```

```
ShearMod = (Vs.^2.*Rho)./1000000;
```

```
a1 = (4*e);
```

```
a2 = ((3*g)*(1-g));
```

```
b1 = (16*e);
```

```
b2 = (3*(3-2*g));
```

```
LN = a1 / a2; %Normal weakness
```

```
LT = b1 / b2; %Tangential weakness
```

```
Lm = Rho*Vp^2-2*Rho*Vs^2; % Lambda Rho
```

```
Mu = Rho*Vs^2; % Mu Rho
```

```
C11 = (Lm + 2*Mu)*(1 - LN)
```

```
C22 = (Lm + 2*Mu)*(1 - (Lm^2/(Lm + 2*Mu)^2)*LN);
```

```
C33 = C22
```

```
C12 = Lm*(1 - LN);
```

```
C13 = C12;
```

```
C21 = C13;
```

```
C31 = C21;
```



```

t1 = 2*Lm*Mu*LN

C23 = C12 + t1;

C32=C23;

C44 =Mu

C55 = Mu*(1 - LT);

C66 = C55


a1 = C11 - C33;

a2 = 2*C33;

b1 = C66 - C44;

b2 = 2*C44

c1 = (C13 + C44)^2;

c2 = (C33 - C44)^2;

c3 = (2*C33*(C33 - C44));


tt = (2*g)*(1 - g)*DN

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%DRY

CASE%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

% output Thomsen's Parameters

E = -1*(tt)

G = -1*(DT/2)

D = -1*(2*g*((1-2*g)*DN + DT))

set(handles.edit7,'String',E)

set(handles.edit8,'String',G)

set(handles.edit9,'String',D)

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

set(handles.edit10,'String',dN)

set(handles.edit11,'String',dT)

```

A.3 ModAz

Azimuthal Amplitude vs. Angle (AVA) Program (MATLAB source code “ModAz”)

This program was designed to model the synthetic azimuthal AVA amplitude and reflectivity using anisotropic parameters from different fracture models (e.g., Hudson, and Linear-slip).

```
global val
```

```
cla reset
```

```
val = get(hObject,'Value')
```

```
set(handles.edit192,'String',num2str(round(val)));
```

```
teta =val*pi/180;
```

```
-----% P-S velocity and density of 3 layer model%-----
```

```
vp1=str2double(char(get(handles.edit179,'String'))); %Layer 1 % P-Velocity
```

```
vp2=str2double(char(get(handles.edit181,'String'))); %Layer 2 % P-Velocity
```

```
vp3=str2double(char(get(handles.edit183,'String'))); %Layer 3 % P-Velocity
```

```
vs1=str2double(char(get(handles.edit180,'String'))); %Layer 1 % S-Velocity
```

```
vs2=str2double(char(get(handles.edit182,'String'))); %Layer 2 % S-Velocity
```

```
vs3=str2double(char(get(handles.edit184,'String'))); %Layer 3 % S-Velocity
```

```
d1=str2double(char(get(handles.rotop,'String'))); %Layer 1 % Density
```

```
d2=str2double(char(get(handles.robot,'String'))); %Layer 2 % Density
```

```
d3=str2double(char(get(handles.edit191,'String'))); %Layer 3 % Density
```

VP1 = (vp1+vp2)/2; % P-Velocity Layer 1

VP2 = (vp2+vp3)/2; % P-Velocity Layer 2

VS1 = (vs1+vs2)/2; % S-Velocity Layer 1

VS2 = (vs2+vs3)/2; % S-Velocity Layer 2

DEN1 =(d1+d2)/2; % Density Layer 1

DEN2 =(d2+d3)/2; % Density Layer 2

t1=68/5900;

t2=t1+58/5500;

t3=t1+t2+87/6100;

A1=((vp2-vp1)/(vp2+vp1)+(d2-d1)/(d2+d1));

A2=((vp3-vp2)/(vp3+vp2)+(d3-d2)/(d3+d2));

B1=(vp2-vp1)/(vp2+vp1)-4*(vs2^2/vp2^2+vs1^2/vp1^2)*(vs2-vs1)/(vs2+vs1)-
2*(vs2^2/vp2^2+vs1^2/vp1^2)*(d2-d1)/(d2+d1);

B2=(vp3-vp2)/(vp3+vp2)-4*(vs3^2/vp3^2+vs2^2/vp2^2)*(vs3-vs2)/(vs3+vs2)-
2*(vs3^2/vp3^2+vs2^2/vp2^2)*(d3-d2)/(d3+d2);

C1=(vp2-vp1)/(vp2+vp1;

C2=(vp3-vp2)/(vp3+vp2;

-----% Anisotropic Parameters 3 layer model%-----

e1 = str2double(char(get(handles.edit172,'String'))); % Epsilon depth 2060 Layer 1

e2 = str2double(char(get(handles.edit187,'String'))); % Epsilon depth 2113 Layer 2

e3 = str2double(char(get(handles.edit188,'String'))); % Epsilon depth 2180 Layer 3

```

g1 = str2double(char(get(handles.edit173,'String'))); % Gamma depth 2060 Layer 1
g2 = str2double(char(get(handles.edit186,'String'))); % Gamma depth 2113 Layer 2
g3 = str2double(char(get(handles.edit189,'String'))); % Gamma depth 2180 Layer 3

```

```

dlt1 = str2double(char(get(handles.edit174,'String'))); % Delta depth 2060 Layer 1
dlt2 = str2double(char(get(handles.edit185,'String'))); % Delta depth 2113 Layer 2
dlt3 = str2double(char(get(handles.edit190,'String'))); % Delta depth 2180 Layer 3

```

```

-----
----- % Azimuthal Amplitude vs. Angle (AVAz) modelling of 3-layer model%-----
-----

```

```

i = get(handles.slider2, 'Value'); % get incidence angle

```

```

for az=1:361 % Azimuth

```

```

% Isotropic Gradient Layer1

```

```

Biso1 = 1/2*((vp2-vp1)/VP1)-2*(VS1/VP1)^2*(d2-d1)/(DEN1)-4*(VS1/VP1)^2*(vs2-vs1)/(VS1);

```

```

% Anisotropic Gradient Layer1

```

```

Baniso1 = 1/2*((dlt2-dlt1)+2*(2*VS1/VP1)^2*(g2-g1));

```

```

Caniso1 = 1/2*((vp2-vp1)/VP1-(e2-e1)*cos(az-0)^4 + (dlt2-dlt1)*sin(az-0)^2*cos(az-0)^2);

```

```

% Isotropic Gradient Layer2

```

```
Biso2 = 1/2*((vp3-vp2)/VP2)-2*(VS2/VP2)^2*(d3-d2)/(DEN2)-4*(VS2/VP2)^2*(vs3-vs2)/(VS2);
```

```
% Anisotropic Gradient Layer2
```

```
Baniso2 = 1/2*((dlt3-dlt2)+2*(2*VS2/VP2)^2*(g3-g2));
```

```
Caniso2 = 1/2*((vp3-vp2)/VP2-(e3-e2)*cos(az-0)^4 + (dlt3-dlt2)*sin(az-0)^2*cos(az-0)^2);
```

```
% Reflectivity Layer 1
```

```
refl(1,az) = A1 + (Biso1 + Baniso1*cos((az-1)*pi/180))^2*sin((i-1)*pi/180)^2 + Caniso1*sin((i-1)^2*pi/180)*tan((i-1)*pi/180)^2;
```

```
% Reflectivity Layer 2
```

```
ref2(1,az) = A1 + (Biso2 + Baniso2*cos((az-1)*pi/180))^2*sin((i-1)*pi/180)^2 + Caniso2*sin((i-1)*pi/180)^2*tan((i-1)*pi/180)^2;
```

```
end
```

```
for az=1:361 % Azimuth
```

```
    for j=1:100
```

```
        R(j,az)=0;
```

```
    end
```

```
R(79,az)=ref2(1,az);
```

```
End
```

```
wave_t=str2double(char(get(handles.edit193,'String'))); %Wave length
```

```
fp=str2double(char(get(handles.edit194,'String'))); % Frequency
```

```
w_t=-0.08:0.001:0.08;
```

```
rick=(1-2*(pi*fp*w_t).^2).*exp(-(pi*fp*w_t).^2); % Ricker Wavelet
```

```

for az=1:361

syn(:,az)=conv(R(:,az),rick);          % Convolution

end


for az=1:361

    for j=110:1:260


        syn_n((j+1-110),az)=syn(j,az);

    end

end


axes(handles.axes12)


% Function to plot synthetic seismic written by Li Teng and Modified T. Mukerji, 1998.

seisplot(syn_n)


% Function to plot synthetic seismic with color filled written by Makvo, 2009.

seisfillcolor("",seis)


t = colorbar('peer',gca,'Tag','colorbar1');

get(t)

ylabel (t, 'Reflectivity')


hline = reline([0 50]);

hline.Color = 'g';

hline.LineWidth = 3;

xlabel('Azimuth');

ylabel('Time(ms)');

```

```

axis([0 365 0 100])

TxT = text(2, 55, 'Horizon reference');

TxT.Color = 'green';

TxT.FontSize = 10;

TxT.FontWeight = 'bold';

depthTARGET = str2double(char(get(handles.text46,'String')))

guidata(hObject,handles)

title(['Depth =' num2str(depthTARGET) 'm'])

disp(depthTARGET)

```

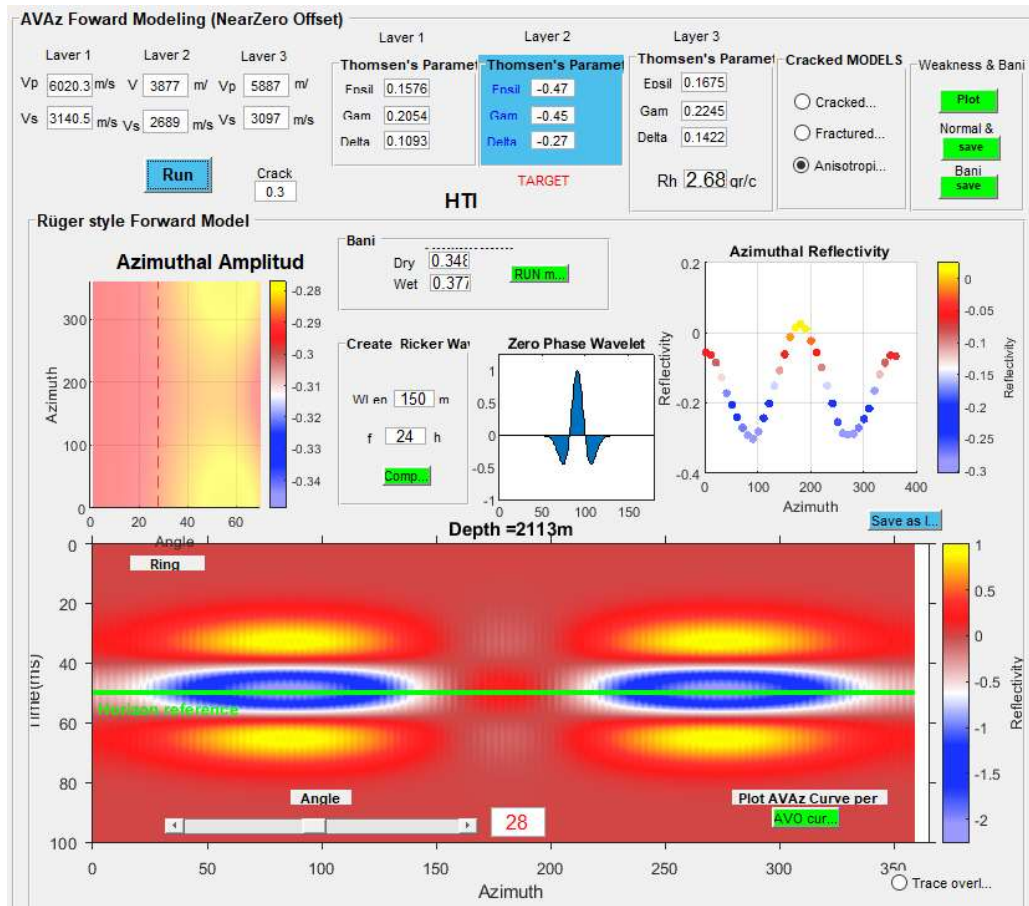


Figure A.1 Graphical User Interface “ModAz” to compute the azimuthal amplitude vs. angle using anisotropic parameters.

A.4 Baniz

Program (MATLAB source code “Baniz” based on the Rüger formulation to estimate the fracture density as a function of incidence angle and full azimuth range.

```
function pushbutton1_Callback(hObject, eventdata, handles)
```

```
% hObject handle to pushbutton1 (see GCBO)
```

```
% eventdata reserved - to be defined in a future version of MATLAB
```

```
% handles structure with handles and user data (see GUIDATA)
```



```

global wave_t fp w_t rick

az = get(hObject,'Value'); %Azimuth

-----% P-S velocity and density of 3 layer model%-----

vp1=str2double(char(get(handles.edit4,'String'))); %Layer 1 P-Velocity
vp2=str2double(char(get(handles.edit2,'String'))); %Layer 2 P-Velocity
vp3=str2double(char(get(handles.edit6,'String'))); %Layer 3 P-Velocity

vs1=str2double(char(get(handles.edit5,'String'))); %Layer 1 S-Velocity
vs2=str2double(char(get(handles.edit3,'String'))); %Layer 2 S-Velocity
vs3=str2double(char(get(handles.edit7,'String'))); %Layer 3 S-Velocity

d1=str2double(char(get(handles.edit19,'String'))); %Layer 1 Density
d2=str2double(char(get(handles.edit18,'String'))); %Layer 2 Density
d3=str2double(char(get(handles.edit20,'String'))); %Layer 3 Density

VP1 = (vp1+vp2)/2; %Layer 1 P-Velocity (average)
VP2 = (vp2+vp3)/2; %Layer 2 P-Velocity (average)
VS1 = (vs1+vs2)/2; %Layer 1 S-Velocity (average)
VS2 = (vs2+vs3)/2; %Layer 2 S-Velocity (average)
DEN1 =(d1+d2)/2; %Layer 1 Density (average)
DEN2 =(d2+d3)/2; %Layer 2 Density (average)

% Time ms for 3-layer model

t1=68/5900;
t2=t1+58/5500;
t3=t1+t2+87/6100;

```

%Intercept layers 1&2

$A1 = ((vp2 - vp1) / (vp2 + vp1) + (d2 - d1) / (d2 + d1));$

$A2 = ((vp3 - vp2) / (vp3 + vp2) + (d3 - d2) / (d3 + d2));$

%Isotropic gradient layers 1&2

$B1 = (vp2 - vp1) / (vp2 + vp1) - 4 * (vs2^2 / vp2^2 + vs1^2 / vp1^2) * (vs2 - vs1) / (vs2 + vs1) -$
 $2 * (vs2^2 / vp2^2 + vs1^2 / vp1^2) * (d2 - d1) / (d2 + d1);$

$B2 = (vp3 - vp2) / (vp3 + vp2) - 4 * (vs3^2 / vp3^2 + vs2^2 / vp2^2) * (vs3 - vs2) / (vs3 + vs2) -$
 $2 * (vs3^2 / vp3^2 + vs2^2 / vp2^2) * (d3 - d2) / (d3 + d2);$

%Curvature layers 1&2

$C1 = (vp2 - vp1) / (vp2 + vp1);$

$C2 = (vp3 - vp2) / (vp3 + vp2);$

%% Anisotropic Parameters%%

$e1 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit10}, 'String')));$ %Epsilon 2060m Layer1

$e2 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit11}, 'String')));$ % Epsilon 2113m Layer2

$e3 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit14}, 'String')));$ % Epsilon 2180m Layer3

$g1 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit9}, 'String')));$ %Gamma 2060m Layer1

$g2 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit12}, 'String')));$ % Gamma 2113m Layer2

$g3 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit15}, 'String')));$ % Gamma 2180m Layer3

$dlt1 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit8}, 'String')));$ %Gamma 2060m Layer1

```

dlt2 =str2double(char(get(handles.edit13,'String')));% Gamma 2113m Layer2

dlt3 =str2double(char(get(handles.edit16,'String')));% Gamma 2180m Layer3


%Isotropic gradient layer1

Biso1 = 1/2*((vp2-vp1)/VP1)-2*(VS1/VP1)^2*(d2-d1)/(DEN1)-4*(VS1/VP1)^2*(vs2-vs1)/(VS1);


%Anisotropic gradient layer1

Baniso1 = 1/2*((dlt2-dlt1)+2*(2*VS1/VP1)^2*(g2-g1));


%Anisotropic Curvature layer1

Caniso1 = 1/2*((vp3-vp1)/VP1-(e2-e1)*cos(az-0)^4 + (dlt2-dlt1)*sin(az-0)^2*cos(az-0)^2);


%Isotropic gradient layer2

Biso2 = 1/2*((vp3-vp2)/VP2)-2*(VS2/VP2)^2*(d3-d2)/(DEN2)-4*(VS2/VP2)^2*(vs3-vs2)/(VS2);


%Anisotropic gradient layer2

Baniso2 = 1/2*((dlt3-dlt2)+2*(2*VS2/VP2)^2*(g3-g2));


%Anisotropic Curvature layer2

Caniso2 = 1/2*((vp3-vp2)/VP2-(e3-e2)*cos(az-0)^4 + (dlt3-dlt2)*sin(az-0)^2*cos(az-0)^2);


%%% Reflectivity%%%%%%%%%%

for i=1:100 %Angles


refl(1,i) = A1 + (Biso1 + Baniso1*cos((az-1)*pi/180))^2*sin((i-1)*pi/180)^2 + Caniso1*sin((i-
1)^2*pi/180)*tan((i-1)*pi/180)^2;


refl(2,i) = A1 + (Biso2 + Baniso2*cos((az-1)*pi/180))^2*sin((i-1)*pi/180)^2 + Caniso2*sin((i-
1)*pi/180)^2*tan((i-1)*pi/180)^2;

```

```

g = (vs2/vp2)^2;

cden = 0.1

tr1 = 4*(((1*8*g^2) + (12*g)-3 ));

tr2 = 3*(3-2*g)*(1-g);

BaniDry = cden * tr1/tr2;


BanisoT = (-1.*(ref2(1,i)-A1-Caniso2*sin((i-1)^2*pi/180)*tan((i-1)*pi/180)^2)/cos((az-
1)*pi/180)^2*sin((i-1)*pi/180)^2)/1000

end

for i=1:100 %Angulos

    for j=1:100

        R(j,i)=0;

    end

    R(79,i)=BanisoT ;

end

for i=1:100

synt(:,i)=conv(R(:,i),rick); % convolution

end

for i=1:100

    for j=110:1:260

        syn_n((j+1-110),i)=synt(j,i);

    end

end

end

axes(handles.axes1)

```

```

%%%%% Plot Bani anisotropic gradient%%%%%%%%%

wigggle(syn_n,'1**');

colormap jet

h = colorbar;

caxis([0 0.5])

ylabel(h, 'Fracture Density')

title('Bani Rüger (NearZero Offset) MODEL');

xlabel('Traces');

ylabel('Time(ms)');

axis([0 100 0 100])

```

A.5 Blangy Model modified

Program (PHYTON source code “Blangy Model” based on the 3-layer model to estimate the anisotropic AVA curves using different fracture models and approaches in anisotropy (e.g., Isotropic, Ryan-grigor, Backus, Hudson, Linear-Slip).

```

import numpy as np

import matplotlib.pyplot as plt

type1 = {'carbonate':{'vp':3300., 'vs':1700., 'rho':2350., 'd':0.00, 'e':0.00},
        'shale_oil':{'vp':4200., 'vs':2700., 'rho':2350., 'd':0.07, 'e':0.14},
        'shale_water': {'vp':4200., 'vs':2100., 'rho':2450., 'd':0.00, 'e':0.00},
        }

type2 = {'carbonate':{'vp':6020., 'vs':3140., 'rho':2620., 'd':0.00, 'e':0.00},
        'shale_oil':{'vp':4742., 'vs':3292., 'rho':2590., 'd':0.07, 'e':0.14},
        'shale_water': {'vp':3322., 'vs':1402., 'rho':2250., 'd':0.00, 'e':0.00},
        }

type3 = {'carbonate':{'vp':2307., 'vs':1108., 'rho':2150., 'd':0.00, 'e':0.00},

```

```

'shale_oil':{'vp':1951., 'vs':1301., 'rho':1950., 'd':0.07, 'e':0.14},
'shale_water':{'vp':1951., 'vs': 930., 'rho':2200., 'd':0.00, 'e':0.00},
}

print (type2['shale_oil']['d'] - type2['carbonate']['d']) # delta-delta
print (type2['shale_oil']['e'] - type2['carbonate']['e']) # delta-epsilon

def blangy(interface, case='gas', i=0):

    upper = interface['carbonate']
    lower = interface['shale_'+case]

    inc_angle = np.radians(i)
    trans_angle = np.arcsin(np.sin(inc_angle) * lower['vp']/upper['vp'])
    theta = 0.5 * (inc_angle + trans_angle)

    vp = (upper['vp'] + lower['vp'])/2.0
    vs = (upper['vs'] + lower['vs'])/2.0
    rho = (upper['rho'] + lower['rho'])/2.0

    dvp = lower['vp'] - upper['vp']
    dvs = lower['vs'] - upper['vs']
    drho = lower['rho'] - upper['rho']
    dd = lower['d'] - upper['d']
    de = lower['e'] - upper['e']

    A = 0.5 * (drho/rho + dvp/vp)

```

$$B = 2.0 * (vs^{**2} / vp^{**2}) * ((drho/rho + 2 * dvs/vs)) * np.sin(theta)**2$$

$$C = 0.5 * (dvp/vp) * np.tan(theta)**2$$

$$D = 0.5 * dd * np.sin(theta)**2$$

$$E = 0.5 * (dd - de) * np.sin(theta)**2 * np.tan(theta)**2$$

$$\text{isotropic} = A - B + C$$

$$\text{anisotropic} = A - B + C + D - E$$

return isotropic, anisotropic, (A, -B, C, D, -E)

theta = np.linspace(0, 40)

#MODEL LAYER FOR AVO CURVE USING ANISOTROPIC VALUES FROM EVERY
FRACTURED MODEL

#RYAN-GRIGOR (THOMSEN'S PARAMETERS)

```
typex = {'carbonate': {'vp':6020., 'vs':3140., 'rho':2620., 'd':0.00, 'e':0.00},
        'shale_oil': {'vp':4742., 'vs':3292., 'rho':2590., 'd':-0.05, 'e':0.11},
        }
```

#BACKUS (THOMSEN'S PARAMETERS)

```
typex2 = {'carbonate': {'vp':6020., 'vs':3140., 'rho':2620., 'd':0.00, 'e':0.00},
        'shale_oil': {'vp':4742., 'vs':3292., 'rho':2590., 'd':-0.05, 'e':0.11},
        }
```

#RUGER (THOMSEN'S PARAMETERS)

```
typex3 = {'carbonate': {'vp':6020., 'vs':3140., 'rho':2620., 'd':0.00, 'e':0.00},
        'shale_oil': {'vp':4742., 'vs':3292., 'rho':2590., 'd':-0.26, 'e':0.03},
        }
```

```

    }

#HUDSON (THOMSEN'S PARAMETERS)

typex4 = {'carbonate':    {'vp':6020., 'vs':3140., 'rho':2620., 'd':0.00, 'e':0.00},
          'shale_oil': {'vp':4742., 'vs':3292., 'rho':2590., 'd':-0.69, 'e':-0.69},
          }

#LINEAR-SLIP (THOMSEN'S PARAMETERS)

typex5 = {'carbonate':    {'vp':6020., 'vs':3140., 'rho':2620., 'd':0.00, 'e':0.00},
          'shale_oil': {'vp':4742., 'vs':3292., 'rho':2590., 'd':-0.66, 'e':-0.18},
          }

rx = blangy(typex, 'oil', theta)
rx2 = blangy(typex2, 'oil', theta)
rx3 = blangy(typex3, 'oil', theta)
rx4 = blangy(typex4, 'oil', theta)
rx5 = blangy(typex5, 'oil', theta)

fig = plt.figure(figsize=(10,10))
ax = fig.add_subplot(111)

ax.plot(theta, rx[0], 'c.', lw=8)
ax.plot(theta, rx[1], 'm', lw=4.0)

#ANHELIDO

ax.plot(theta, rx2[1], 'k', lw=2.0)
ax.plot(theta, rx3[1], 'C1', lw=5.0)

```



```

ax.plot(theta, rx4[1], 'b', lw=5.0)
ax.plot(theta, rx5[1], 'r', lw=5.0)
ax.plot(theta, rx6[1], 'g', lw=5.0)

#SERBAL-1
ax.set_ylim(-0.3, 0.1)

plt.xlabel('ANGLE of INCIDENCE (in degrees)', size=12)
plt.ylabel('REFLECTION AMPLITUDE', size=12)
plt.xticks(np.arange(0,50,10))

#ax.text(30, rx[0][20]+0.014,'isotropic', color='k', size='12', ha='center')
#ax.text(30, rx[1][20]-0.04,'anisotropic', color='k', size='12', ha='center', rotation=-10)
plt.gca().legend(('Isotropic','RyanGrigor','Backus','Ruger','Hudson','Linear-slip'))
plt.show()

```

Appendix B

B.1 DEMmodR1.m

Program (MATLAB source code “DEMmodR1” based on the Differential effective medium the to estimate the bulk K_{dry} and shear modulus μ_{dry} using this analytical model

```
function varargout = DEMmodR1(varargin)

% DEMMODR1 MATLAB code for DEMmodR1.fig

% DEMMODR1, by itself, creates a new DEMMODR1 or raises the existing
% singleton*.

%
% H = DEMMODR1 returns the handle to a new DEMMODR1 or the handle to
% the existing singleton*.

%
% DEMMODR1('CALLBACK',hObject,eventData,handles,...) calls the local
% function named CALLBACK in DEMMODR1.M with the given input arguments.

%
% DEMMODR1('Property','Value',...) creates a new DEMMODR1 or raises the
% existing singleton*. Starting from the left, property value pairs are
% applied to the GUI before DEMmodR1_OpeningFcn gets called. An
% unrecognized property name or invalid value makes property application
% stop. All inputs are passed to DEMmodR1_OpeningFcn via varargin.

%
% *See GUI Options on GUIDE's Tools menu. Choose "GUI allows only one
% instance to run (singleton)".

% See also: GUIDE, GUIDATA, GUIHANDLES

% Edit the above text to modify the response to help DEMmodR1

% Last Modified by GUIDE v2.5 13-Feb-2023 21:03:24
```

```

% Begin initialization code - DO NOT EDIT

gui_Singleton = 1;

gui_State = struct('gui_Name',    mfilename, ...
                  'gui_Singleton', gui_Singleton, ...
                  'gui_OpeningFcn', @DEMmodR1_OpeningFcn, ...
                  'gui_OutputFcn', @DEMmodR1_OutputFcn, ...
                  'gui_LayoutFcn', [], ...
                  'gui_Callback', []);

if nargin && ischar(varargin{1})
    gui_State.gui_Callback = str2func(varargin{1});
end

if nargout
    [varargout{1:nargout}] = gui_mainfcn(gui_State, varargin{:});
else
    gui_mainfcn(gui_State, varargin{:});
end

% End initialization code - DO NOT EDIT


% --- Executes just before DEMmodR1 is made visible.
function DEMmodR1_OpeningFcn(hObject, eventdata, handles, varargin)

% This function has no output args, see OutputFcn.

% hObject    handle to figure

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)

% varargin   command line arguments to DEMmodR1 (see VARARGIN)


% Choose default command line output for DEMmodR1
handles.output = hObject;

```

```

% Update handles structure

guidata(hObject, handles);

% UIWAIT makes DEMmodR1 wait for user response (see UIRESUME)

% uiwait(handles.figure1);

% --- Outputs from this function are returned to the command line.

function varargout = DEMmodR1_OutputFcn(hObject, eventdata, handles)

% varargout cell array for returning output args (see VARARGOUT);

% hObject    handle to figure

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)

% Get default command line output from handles structure

varargout{1} = handles.output;

% --- Executes on button press in pushbutton1.

function pushbutton1_Callback(hObject, eventdata, handles)

% hObject    handle to pushbutton1 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)

global Depth Vp1 Vs1 bulklog phi Sw1 toc vclay vqz vca vdol asp Rmat Rw Roil Km Um

[file,path] = uigetfile({'*.xls;*.xlsx','Excel Files'}, 'Select data file');

filename = strcat(path,file);

data = xlsread(filename);

Depth = data(:,1); %Depth (m)

```

```

Vp1 = data(:,2); % P-wave log
Vs1 = data(:,3); % S-wave log
bulklog = data(:,4); % Bulk Modulus log
phi = data(:,6); % Porosity
Swl = data(:,7); % Water saturation
toc = data(:,8); % TOC log
vclay = data(:,9); % Vclay fraction
vqz=data(:,10); % Quartz fraction
vca=data(:,11); % Calcite fraction
vdol=data(:,12); % Dolomite fraction

asp = str2num(char(get(handles.edit1,'String'))); %Aspect ratio
Rmat = str2num(char(get(handles.edit2,'String'))); %Matrix density
Rw = str2num(char(get(handles.edit3,'String'))); %Water density
Roil = str2num(char(get(handles.edit4,'String'))); %Oil density
Km=str2num(char(get(handles.edit6,'String'))); %Bulk Modulus matrix
Um=str2num(char(get(handles.edit7,'String'))); %Shear Modulus matrix

```

```

% --- Executes on button press in pushbutton2.

function pushbutton2_Callback(hObject, eventdata, handles)

% hObject    handle to pushbutton2 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    structure with handles and user data (see GUIDATA)


global Depth Vp1 Vs1 bulklog phi Sw1 toc vclay vqz vca vdol asp Rmat Rw Roil Km Um


So1 = (1-Sw1); %OIL SATURATION


Rsat1 = Rmat.*(1-phi)+(So1.*Roil + Sw1.*Rw).*phi;
ROH = Rsat1./1000;


Mu1 = (Vs1.^2.* Rsat1)
MU = Mu1./1000000


Ksat1 = Vp1.^2.*2.32- 4/3.*Mu1;
KSAT1 = Ksat1./1000000;


VPinsitu = (sqrt((KSAT1+((4/3).*MU))./2.32)).*1000;
tet =(asp./((1-asp.^2).^3/2)).*(acos(asp)-(asp.*sqrt(1-asp.^2)));
g = ((asp.^2)./(1-asp.^2)).*((3.*tet)-2);


KU = Km/Um;
z = (1/(pi.*asp))-(1/(pi.*asp.*((3.*Km./(Um +1)))));

```

DE M Assuming Penny Cracks

$v1 = Km/U_m;$

$v2 = ((3 * Km)/U_m) + 4 ;$

$v3 = ((3 * Km)/U_m) + 1 ;$

$v4 = ((3 * Km)/U_m) + 2 ;$

$a = (-1. * (1/5)) + (KU. * v2. / (pi. * asp * (v3))) - (4. * v2 / (15. * pi. * asp. * (v3))) - (8. * v2 / (15. * pi. * asp. * (v4))) - (KU. * ((1 / pi. * asp) + (27. / (5. * pi. * asp * v3.^2)) + (16. / (5. * pi. * asp. * v4.^2)))));$

$b = (1 / pi. * asp) + (27 / (5. * pi. * asp. * v3.^2)) + (16. / (5. * pi. * asp. * v4.^2));$

$x = (2 - (3. * g) - (2. * tet)) / (2. * ((2. * tet) - (3. * tet.^2) - (2. * g)))$

$KDRY1 = Km. * ((1 - phi).^z / (1 + (b./a). * KU - (b./a). * KU. * (1 - phi).^a).^(x./b))$

$V_{psat} = \sqrt{((K_{SAT1} + ((4./3). * MU)) / R_{sat1})} * 1000;$

$V_{ssat} = \sqrt{MU./2.32} * 1000;$

$BulkMod = (((V_{psat}.^2) - ((4./3). * V_{s1}.^2)). * 2.32) / 1000000;$

$S0 = (2 - (3. * g) - (3. * tet)) / (2. * ((2. * tet) - (3. * tet.^2) - (2. * g)));$

$S1 = ((tet - g) / (2 - (3. * g) - (3. * tet)));$

$S2 = (4./3);$


```

S3 = (2.*(tet-g))./(3.*((2.*tet)-(3.*tet.^2)-(2.*g)));
tm1=(1-phi).*S0;
tm2 = (S1+S2-S3)-(((S1-S3).*(S2-S3))./(S3+(Km./Um)));
tm3= (1 + ((b.*Km)./(a.*Um)) - ((b.*Km)./(a.*Um)).*((1-phi).^a)).^(S0./b);
tm4= (1 + ((b.*Km)./(a.*Um)) - ((b.*Km)./(a.*Um)).*((1-phi).^a)).^((S0./b)-1);
MDRY1= (Um.* (((tm1.*tm2)-a)./tm4));

```

```

axes(handles.axes1)
plot(Vp1, Depth,'k')
set(gca,'YDir','Reverse')
grid on
xlim([0 6500])
hold on
plot(Vpsat, Depth,'r')
title('DEM modelling')
xlabel('Velocity(m\s)')
ylabel('Depth(m)')
set(gca,'YDir','Reverse')
legend('Vp logged (m\s)','Vp model (m\s)');

```

```

axes(handles.axes2)
plot(Vs1, Depth,'k')
set(gca,'YDir','Reverse')
grid on
xlim([0 6500])
hold on

```

```

plot(Vssat, Depth,'R')

title('DEM modelling')

xlabel('Velocity(m\s)')

ylabel('Depth(m)')

set(gca,'YDir','Reverse')

legend('Vs logged (m\s)','Vs model (m\s)');

function edit6_Callback(hObject, eventdata, handles)

% hObject    handle to edit6 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)

% Hints: get(hObject,'String') returns contents of edit6 as text
%        str2double(get(hObject,'String')) returns contents of edit6 as a double

% --- Executes during object creation, after setting all properties.
function edit6_CreateFcn(hObject, eventdata, handles)

% hObject    handle to edit6 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    empty - handles not created until after all CreateFcns called

% Hint: edit controls usually have a white background on Windows.
%        See ISPC and COMPUTER.
if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))
    set(hObject,'BackgroundColor','white');
end

```

```

function edit7_Callback(hObject, eventdata, handles)

% hObject    handle to edit7 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)


% Hints: get(hObject,'String') returns contents of edit7 as text
%        str2double(get(hObject,'String')) returns contents of edit7 as a double


% --- Executes during object creation, after setting all properties.
function edit7_CreateFcn(hObject, eventdata, handles)

% hObject    handle to edit7 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    empty - handles not created until after all CreateFcns called


% Hint: edit controls usually have a white background on Windows.
%        See ISPC and COMPUTER.
if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))
    set(hObject,'BackgroundColor','white');
end


function edit2_Callback(hObject, eventdata, handles)

% hObject    handle to edit2 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)

```

```

% Hints: get(hObject,'String') returns contents of edit2 as text
%      str2double(get(hObject,'String')) returns contents of edit2 as a double


% --- Executes during object creation, after setting all properties.
function edit2_CreateFcn(hObject, eventdata, handles)
% hObject    handle to edit2 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    empty - handles not created until after all CreateFcns called


% Hint: edit controls usually have a white background on Windows.
%      See ISPC and COMPUTER.
if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))
    set(hObject,'BackgroundColor','white');
end


function edit3_Callback(hObject, eventdata, handles)
% hObject    handle to edit3 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    structure with handles and user data (see GUIDATA)


% Hints: get(hObject,'String') returns contents of edit3 as text
%      str2double(get(hObject,'String')) returns contents of edit3 as a double


% --- Executes during object creation, after setting all properties.
function edit3_CreateFcn(hObject, eventdata, handles)

```

```

% hObject    handle to edit3 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    empty - handles not created until after all CreateFcns called


% Hint: edit controls usually have a white background on Windows.

%    See ISPC and COMPUTER.

if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))
    set(hObject,'BackgroundColor','white');
end

```

```

function edit4_Callback(hObject, eventdata, handles)

% hObject    handle to edit4 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)


% Hints: get(hObject,'String') returns contents of edit4 as text
%    str2double(get(hObject,'String')) returns contents of edit4 as a double

```

```

% --- Executes during object creation, after setting all properties.

function edit4_CreateFcn(hObject, eventdata, handles)

% hObject    handle to edit4 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    empty - handles not created until after all CreateFcns called


% Hint: edit controls usually have a white background on Windows.

%    See ISPC and COMPUTER.

```

```

if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))

set(hObject,'BackgroundColor','white');

end

function edit1_Callback(hObject, eventdata, handles)

% hObject    handle to edit1 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)

% Hints: get(hObject,'String') returns contents of edit1 as text
%        str2double(get(hObject,'String')) returns contents of edit1 as a double

% --- Executes during object creation, after setting all properties.

function edit1_CreateFcn(hObject, eventdata, handles)

% hObject    handle to edit1 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    empty - handles not created until after all CreateFcns called

% Hint: edit controls usually have a white background on Windows.

%        See ISPC and COMPUTER.

if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))

    set(hObject,'BackgroundColor','white');

end

% --- Executes on button press in pushbutton3.

function pushbutton3_Callback(hObject, eventdata, handles)

% hObject    handle to pushbutton3 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)

global Depth Vp1 Vs1 bulklog phi Sw1 toc vclay vqz vca vdol asp Rmat Rw Roil Km Um

% figure

asp2 = 0.1:0.2:1;

hold on

for i = 1:5

```

```

So1 = (1-Sw1 ); %Oil saturation

Rsat1 = Rmat.*(1-phi)+(So1.*Roil + Sw1.*Rw).*phi;

ROH = Rsat1./1000;

Mu1 = (Vs1.^2.* Rsat1);

MU = Mu1./1000000

Ksat1 = Vp1.^2.*2.32- 4/3.*Mu1;

KSAT1 = Ksat1./1000000;

VPinsitu = (sqrt((KSAT1+((4/3).*MU))./2.32)).*1000;

tet2 =(asp2./((1-asp2.^2).^ (3/2))).*(acos(asp2)-(asp2.*sqrt(1-asp2.^2)));

g2 = ((asp2.^2)./(1-asp2.^2)).*((3.*tet2)-2);

KU = Km./Um;

z = (1./(pi.*asp2))-(1./(pi.*asp2.*((3.*Km./(Um +1)))));

%%%%%%%%%%%%Assuming Penny

Cracks%%%%%%%%%%%%

%%%%%%%%%%%%

%%%%%%%%%%%%

%%%%%%%%%%%%

%%%%%%%%%%%%

%%%%%%%%%%%%

%%%%%%%%%%%%

v1 = Km/Um;

v2 =((3*Km)/Um)+ 4 ;

v3 = ((3*Km)/Um)+ 1 ;

v4 = ((3*Km)/Um)+ 2 ;

a = (-1.*(1/5))+(KU.*v2./(pi.*asp2*(v3))) - (4.*v2./(15.*pi.*asp2.*(v3))) - (8.*v2./(15.*pi.*asp2.*(v4))) -
(KU .* ((1./pi.*asp2) + (27./(5.*pi.*asp2.*v3.^2)) + (16./(5.*pi.*asp2.*v4.^2))));

b=(1./pi.*asp2) + (27./(5.*pi.*asp2.*v3.^2)) + (16./(5.*pi.*asp2.*v4.^2));

x = (2- (3.*g2) - (2.*tet2))./(2 .* ((2.*tet2)- (3.*tet2.^2) - (2.*g2)))

KDRY1 = Km.*((1-phi).^z./(1 + (b./a).*KU - (b./a).*KU.*(1 - phi).^a).^(x./b))

axes(handles.axes3)

```

```

s=scatter(phi, KDRY1(:,1),'.');

s.LineWidth = 0.6;

s.MarkerEdgeColor = 'k';

s.MarkerFaceColor = [0 0 0];

grid on

```

```

xlim([0.02 0.1])

```

```

ylim([20 45])

```

```

hold on

```

```

s5=scatter(phi, KDRY1(:,2),'.');

s5.LineWidth = 0.6;

s5.MarkerEdgeColor = 'b';

s5.MarkerFaceColor = [0 0 0];

grid on

```

```

hold on

```

```

s5=scatter(phi, bulklog,'.');

s5.LineWidth = 0.6;

s5.MarkerEdgeColor = 'm';

s5.MarkerFaceColor = [0 0 0];

grid on

```

```

hold on

```

```

s5=scatter(phi, KDRY1(:,4),'.');

s5.LineWidth = 0.6;

s5.MarkerEdgeColor = 'r';

s5.MarkerFaceColor = [0 0 0];

grid on

```

```

hold on

```

```

s5=scatter(phi, KDRY1(:,5),'.');

s5.LineWidth = 0.6;

```



```

s5.MarkerEdgeColor = 'g';
s5.MarkerFaceColor = [0 0 0];
grid on
hold on
s5=scatter(phi, KDRY1(:,5),'.');
s5.LineWidth = 0.6;
s5.MarkerEdgeColor = 'g';
s5.MarkerFaceColor = [0 0 0];
hold on
f2=toc;
s5=scatter(phi, bulklog,45,f2,'filled');
s5.LineWidth = 0.9;
s5.MarkerEdgeColor = 'k';
s5.MarkerFaceColor = [0 0.9 0.1];
grid on
end
title('DEM analysis Phi vs Bulk Modulus \alpha=aspect ratio')
xlabel('PHI (deg)')
ylabel('Bulk Modulus (GPa) DEM')
legend('\alpha=0.1','\alpha=0.3','\alpha=0.5','\alpha=0.7','\alpha=0.9','log samples')
% --- Executes on selection change in popupmenu1.
function popupmenu1_Callback(hObject, eventdata, handles)
% hObject handle to popupmenu1 (see GCBO)
% eventdata reserved - to be defined in a future version of MATLAB
% handles structure with handles and user data (see GUIDATA)

% Hints: contents = cellstr(get(hObject,'String')) returns popupmenu1 contents as cell array
% contents{get(hObject,'Value')} returns selected item from popupmenu1
global Vp1 vclay toc popVal popVal1 popVal2 popVal3

```

```

contents = cellstr(get(hObject,'String'));

popChoice = contents{get(hObject,'Value')};

assignin('base','popChoice',popChoice);

if (strcmp(popChoice,'Vp'))

    popVal = Vp1;

elseif (strcmp(popChoice,'Vclay'))

popVal = vclay;

elseif (strcmp(popChoice,'TOC'))

popVal = toc;

end

assignin('base','popVal',popVal)

guidata(hObject, handles);

% --- Executes during object creation, after setting all properties.

function popupmenu1_CreateFcn(hObject, eventdata, handles)

% hObject    handle to popupmenu1 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    empty - handles not created until after all CreateFcns called

% Hint: popupmenu controls usually have a white background on Windows.

%    See ISPC and COMPUTER.

if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))

set(hObject,'BackgroundColor','white');

end

% --- Executes on selection change in popupmenu2.

function popupmenu2_Callback(hObject, eventdata, handles)

% hObject    handle to popupmenu2 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)

% Hints: contents = cellstr(get(hObject,'String')) returns popupmenu2 contents as cell array

%    contents{get(hObject,'Value')} returns selected item from popupmenu2

global Vp1 vclay toc

```

```

contents = cellstr(get(hObject,'String'));
popChoice = contents{get(hObject,'Value')};
assignin('base','popChoice',popChoice);
if (strcmp(popChoice,'Vp'))
    popVal1 = Vp1;
elseif (strcmp(popChoice,'Vclay'))
    popVal1 = vclay;
elseif (strcmp(popChoice,'TOC'))
    popVal1 = toc;
end
assignin('base','popVal1',popVal1)
guidata(hObject, handles);
% --- Executes during object creation, after setting all properties.
function popupmenu2_CreateFcn(hObject, eventdata, handles)
% hObject    handle to popupmenu2 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    empty - handles not created until after all CreateFcns called
% Hint: popupmenu controls usually have a white background on Windows.
%    See ISPC and COMPUTER.
if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))
    set(hObject,'BackgroundColor','white');
end
% --- Executes on selection change in popupmenu3.
function popupmenu3_Callback(hObject, eventdata, handles)
% hObject    handle to popupmenu3 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    structure with handles and user data (see GUIDATA)
% Hints: contents = cellstr(get(hObject,'String')) returns popupmenu3 contents as cell array
%    contents{get(hObject,'Value')} returns selected item from popupmenu3

```

```
global Vp1 vclay toc popVal popVal1 popVal2 popVal3
```

```
contents = cellstr(get(hObject,'String'));
popChoice = contents{get(hObject,'Value')};
assignin('base','popChoice',popChoice);
if (strcmp(popChoice,'Vp'))
    popVal2 = Vp1;
elseif (strcmp(popChoice,'Vclay'))
    popVal2 = vclay;
elseif (strcmp(popChoice,'TOC'))
    popVal2 = toc;
end
assignin('base','popVal2',popVal2)
guidata(hObject, handles);
% --- Executes during object creation, after setting all properties.
function popupmenu3_CreateFcn(hObject, eventdata, handles)
% hObject    handle to popupmenu3 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    empty - handles not created until after all CreateFcns called
% Hint: popupmenu controls usually have a white background on Windows.
% See ISPC and COMPUTER.
if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))
    set(hObject,'BackgroundColor','white');
end
```

```
% --- Executes on selection change in popupmenu4.
function popupmenu4_Callback(hObject, eventdata, handles)
% hObject    handle to popupmenu4 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
```

```

% handles    structure with handles and user data (see GUIDATA)

% Hints: contents = cellstr(get(hObject,'String')) returns popupmenu4 contents as cell array

%    contents{get(hObject,'Value')} returns selected item from popupmenu4

global Vp1 vclay toc popVal popVal1 popVal2 popVal3


contents = cellstr(get(hObject,'String'));

popChoice = contents{get(hObject,'Value')};

assignin('base','popChoice',popChoice);


if (strcmp(popChoice,'Vp'))

    popVal3 = Vp1;

elseif (strcmp(popChoice,'Vclay'))

    popVal3 = vclay;

elseif (strcmp(popChoice,'TOC'))

    popVal3 = toc;

end

assignin('base','popVal3',popVal3)

guidata(hObject, handles);


% --- Executes during object creation, after setting all properties.

function popupmenu4_CreateFcn(hObject, eventdata, handles)

% hObject    handle to popupmenu4 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    empty - handles not created until after all CreateFcns called

% Hint: popupmenu controls usually have a white background on Windows.

%    See ISPC and COMPUTER.

if ispc && isequal(get(hObject,'BackgroundColor'), get(0,'defaultUicontrolBackgroundColor'))

    set(hObject,'BackgroundColor','white');

end

% --- Executes on button press in pushbutton4.

```

```

function pushbutton4_Callback(hObject, eventdata, handles)

% hObject    handle to pushbutton4 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    structure with handles and user data (see GUIDATA)


x = evalin('base','popVal');
y = evalin('base','popVal1');
z = evalin('base','popVal2');
C1 = evalin('base','popVal3');


axes(handles.axes4)


sr = scatter3(x,y,z,30,C1,'filled')
sr.MarkerEdgeColor = 'k';

InteractiveColorbar


grid on

set(gca, 'Projection','perspective')

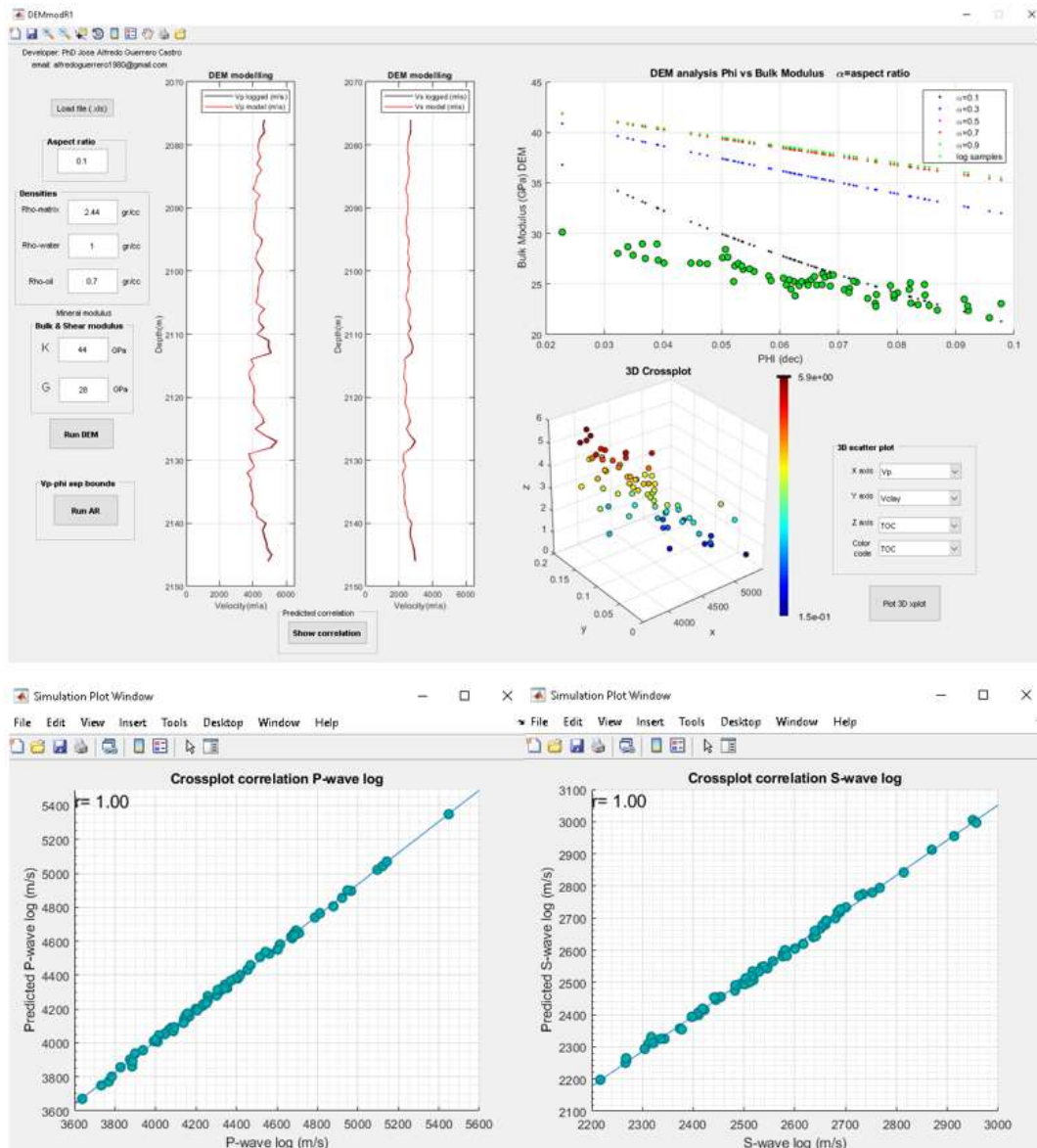

title('3D Crossplot')

get(hObject,'Value')

xlabel('x')
ylabel('y')
zlabel('z')

guidata(hObject, handles);

```



DEMmodR1 GUI graphical user interface

B.2 FluidAnisoMod.m

Program (MATLAB source code GUI “FluidAnisoMod” based on fluid substitution in shale rocks using Brown and Korrunga formulation.

```
function radiobutton1_Callback(hObject, eventdata, handles)

% hObject    handle to radiobutton1 (see GCBO)

% eventdata reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)


global wave_t fp w_t rick


vp1=str2double(char(get(handles.edit21,'String'))); %Layer 1
vp2=str2double(char(get(handles.edit19,'String'))); %Layer 2
vp3=str2double(char(get(handles.edit23,'String'))); %Layer 3


vs1=str2double(char(get(handles.edit22,'String'))); %Layer 1
vs2=str2double(char(get(handles.edit20,'String'))); %Layer 2
vs3=str2double(char(get(handles.edit24,'String'))); %Layer 3


d1=str2double(char(get(handles.edit33,'String'))); % Layer 1
d2=str2double(char(get(handles.edit32,'String'))); % Layer 2
d3=str2double(char(get(handles.edit34,'String'))); % Layer 3


VP1 = (vp1+vp2)/2;
VP2 = (vp2+vp3)/2;
VS1 = (vs1+vs2)/2;
VS2 = (vs2+vs3)/2;
DEN1 =(d1+d2)/2;
DEN2 =(d2+d3)/2;
```



```
t1=68/5900;
```

```
t2=t1+58/5500;
```

```
t3=t1+t2+87/6100;
```

```
A1=((vp2-vp1)/(vp2+vp1)+(d2-d1)/(d2+d1));
```

```
A2=((vp3-vp2)/(vp3+vp2)+(d3-d2)/(d3+d2));
```

```
B1=(vp2-vp1)/(vp2+vp1)-4*(vs2^2/vp2^2+vs1^2/vp1^2)*(vs2-vs1)/(vs2+vs1)-  
2*(vs2^2/vp2^2+vs1^2/vp1^2)*(d2-d1)/(d2+d1);
```

```
B2=(vp3-vp2)/(vp3+vp2)-4*(vs3^2/vp3^2+vs2^2/vp2^2)*(vs3-vs2)/(vs3+vs2)-  
2*(vs3^2/vp3^2+vs2^2/vp2^2)*(d3-d2)/(d3+d2);
```

```
C1=(vp2-vp1)/(vp2+vp1);
```

```
C2=(vp3-vp2)/(vp3+vp2);
```

```
e1 = str2double(char(get(handles.edit27,'String')));
```

```
e2 = str2double(char(get(handles.edit12,'String')));
```

```
e3 = str2double(char(get(handles.edit28,'String')));
```

```
g1 = str2double(char(get(handles.edit26,'String')));
```

```
g2 = str2double(char(get(handles.edit13,'String')));
```

```
g3 = str2double(char(get(handles.edit29,'String')));
```

```
dlt1 = str2double(char(get(handles.edit25,'String')));
```

```
dlt2 = str2double(char(get(handles.edit14,'String')));
```

```
dlt3 = str2double(char(get(handles.edit30,'String')));
```

```
% Hint: get(hObject,'Value') returns toggle state of radiobutton1
```

```
i = str2double(char(get(handles.edit18,'String')));
```

```

for az=1:361

Biso1 = 1/2*((vp2-vp1)/VP1)-2*(VS1/VP1)^2*(d2-d1)/(DEN1)-4*(VS1/VP1)^2*(vs2-vs1)/(VS1);
Baniso1 = 1/2*((dlt2-dlt1)+2*(2*VS1/VP1)^2*(g2-g1));
Caniso1 = 1/2*((vp2-vp1)/VP1-(e2-e1)*cos(az-0)^4 + (dlt2-dlt1)*sin(az-0)^2*cos(az-0)^2);

Biso2 = 1/2*((vp3-vp2)/VP2)-2*(VS2/VP2)^2*(d3-d2)/(DEN2)-4*(VS2/VP2)^2*(vs3-vs2)/(VS2);
Baniso2 = 1/2*((dlt3-dlt2)+2*(2*VS2/VP2)^2*(g3-g2));
Caniso2 = 1/2*((vp3-vp2)/VP2-(e3-e2)*cos(az-0)^4 + (dlt3-dlt2)*sin(az-0)^2*cos(az-0)^2);

ref1(1,az) = A1 + (Biso1 + Baniso1*cos((az-1)*pi/180))^2*sin((i-1)*pi/180)^2 + Caniso1*sin((i-
1)^2*pi/180)*tan((i-1)*pi/180)^2;
ref2(1,az) = A1 + (Biso2 + Baniso2*cos((az-1)*pi/180))^2*sin((i-1)*pi/180)^2 + Caniso2*sin((i-
1)*pi/180)^2*tan((i-1)*pi/180)^2;

end

for az=1:361 %Azimuth

for j=1:100

R(j,az)=0;

end

R(79,az)=ref2(1,az);

end

for az=1:361

syn(:,az)=conv(R(:,az),rick); % convolution

end

for az=1:361

for j=110:1:260

syn_n((j+1-110),az)=syn(j,az);

end

```

```

end

%%Plot synthetic seismogram%%

axes(handles.axes1)

seisplot(syn_n)

seisfillcolor("",seis)

t = colorbar('peer',gca,'Tag','colorbar');

get(t)

ylabel(t, 'Reflectivity')

hline = reline([0 60]);

hline.Color = 'g';

hline.LineWidth = 3;

xlabel('Azimuth');

ylabel('Time(ms)');

axis([0 365 0 100])

xlim([0,360])

TxT = text(2, 55, 'Horizon reference');

TxT.Color = 'green';

TxT.FontSize = 10;

TxT.FontWeight = 'bold';

TxT2 = text(2,90, 'DRY case');

TxT2.FontSize = 10;

TxT2.FontWeight = 'bold';

guidata(hObject,handles)

axes(handles.axes6)

for az=1:361

s = scatter(az,ref2(1,az));

```

```

s.LineWidth = 0.6;

s.MarkerEdgeColor = 'k';

s.MarkerFaceColor = [1 0 0];

```

```

hold on

xlabel('Azimuth')

ylabel('Time(ms)')

title('Azimuthal Reflectivity')

grid on

end

```

```

% --- Executes on button press in radiobutton2.

function radiobutton2_Callback(hObject, eventdata, handles)

% hObject    handle to radiobutton2 (see GCBO)

% eventdata  reserved - to be defined in a future version of MATLAB

% handles    structure with handles and user data (see GUIDATA)


% Hint: get(hObject,'Value') returns toggle state of radiobutton2

global wave_t fp w_t rick AZ

vp1=str2double(char(get(handles.edit21,'String'))); %Layer 1
vp2=str2double(char(get(handles.edit19,'String'))); %Layer 2
vp3=str2double(char(get(handles.edit23,'String'))); %Layer 3


vs1=str2double(char(get(handles.edit22,'String'))); %Layer 1
vs2=str2double(char(get(handles.edit20,'String'))); %Layer 2
vs3=str2double(char(get(handles.edit24,'String'))); %Layer 3


d1=str2double(char(get(handles.edit33,'String'))); %Layer 1
d2=str2double(char(get(handles.edit32,'String'))); %Layer 2
d3=str2double(char(get(handles.edit34,'String'))); %Layer 3

```

$$VP1 = (vp1+vp2)/2;$$

$$VP2 = (vp2+vp3)/2;$$

$$VS1 = (vs1+vs2)/2;$$

$$VS2 = (vs2+vs3)/2;$$

$$DEN1 = (d1+d2)/2;$$

$$DEN2 = (d2+d3)/2;$$

$$t1=68/5900;$$

$$t2=t1+58/5500;$$

$$t3=t1+t2+87/6100;$$

$$A1=((vp2-vp1)/(vp2+vp1)+(d2-d1)/(d2+d1));$$

$$A2=((vp3-vp2)/(vp3+vp2)+(d3-d2)/(d3+d2));$$

$$B1=(vp2-vp1)/(vp2+vp1)-4*(vs2^2/vp2^2+vs1^2/vp1^2)*(vs2-vs1)/(vs2+vs1)-2*(vs2^2/vp2^2+vs1^2/vp1^2)*(d2-d1)/(d2+d1);$$

$$B2=(vp3-vp2)/(vp3+vp2)-4*(vs3^2/vp3^2+vs2^2/vp2^2)*(vs3-vs2)/(vs3+vs2)-2*(vs3^2/vp3^2+vs2^2/vp2^2)*(d3-d2)/(d3+d2);$$

$$C1=(vp2-vp1)/(vp2+vp1);$$

$$C2=(vp3-vp2)/(vp3+vp2);$$

$$e1 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit27}, 'String')));$$

$$e2 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit15}, 'String')));$$

$$e3 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit28}, 'String')));$$

$$g1 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit26}, 'String')));$$

$$g2 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit16}, 'String')));$$

$$g3 = \text{str2double}(\text{char}(\text{get}(\text{handles.edit29}, 'String')));$$

```

dlt1 = str2double(char(get(handles.edit25,'String')));
dlt2 = str2double(char(get(handles.edit17,'String')));
dlt3 = str2double(char(get(handles.edit30,'String')));

i = str2double(char(get(handles.edit18,'String')));

for az=1:361

Biso1 = 1/2*((vp2-vp1)/VP1)-2*(VS1/VP1)^2*(d2-d1)/(DEN1)-4*(VS1/VP1)^2*(vs2-vs1)/(VS1);
Baniso1 = 1/2*((dlt2-dlt1)+2*(2*VS1/VP1)^2*(g2-g1));
Caniso1 = 1/2*((vp2-vp1)/VP1-(e2-e1)*cos(az-0)^4 + (dlt2-dlt1)*sin(az-0)^2*cos(az-0)^2);

Biso2 = 1/2*((vp3-vp2)/VP2)-2*(VS2/VP2)^2*(d3-d2)/(DEN2)-4*(VS2/VP2)^2*(vs3-vs2)/(VS2);
Baniso2 = 1/2*((dlt3-dlt2)+2*(2*VS2/VP2)^2*(g3-g2));
Caniso2 = 1/2*((vp3-vp2)/VP2-(e3-e2)*cos(az-0)^4 + (dlt3-dlt2)*sin(az-0)^2*cos(az-0)^2);

ref1(1,az) = A1 + (Biso1 + Baniso1*cos((az-1)*pi/180))^2*sin((i-1)*pi/180)^2 + Caniso1*sin((i-1)^2*pi/180)*tan((i-1)*pi/180)^2;
ref2(1,az) = A1 + (Biso2 + Baniso2*cos((az-1)*pi/180))^2*sin((i-1)*pi/180)^2 + Caniso2*sin((i-1)*pi/180)^2*tan((i-1)*pi/180)^2;

end

for az=1:361 %Azimuth

    for j=1:100

        R(j,az)=0;

    end

R(79,az)=ref2(1,az);

end

```

```

for az=1:361
syn(:,az)=conv(R(:,az),rick); % convolution
end

for az=1:361
for j=110:1:260

syn_n((j+1-110),az)=syn(j,az);

end

end

%%Plot synthetic seismogram%%
axes(handles.axes1)
seisplot(syn_n)
seisfillcolor("",seis)
t = colorbar('peer',gca,'Tag','colorbar2');
get(t)
ylabel(t, 'Reflectivity')

hline = reline([0 60]);
hline.Color = 'g';
hline.LineWidth = 3;

xlabel('\phi')
ylabel('Time(ms)')
title('Azimuthal Reflectivity')
axis([0 365 0 100])
set(gca,'Ydir','reverse')

```

```

TxT = text(2, 55, 'Horizon reference');
TxT.Color = 'green';
TxT.FontSize = 10;
TxT.FontWeight = 'bold';

```

```

TxT2 = text(2,90, 'SATURATED case');
TxT2.FontSize = 10;
TxT2.FontWeight = 'bold';

```

```

axes(handles.axes6)
for az=1:361
s = scatter(az,ref2(1,az));
s.LineWidth = 0.6;
s.MarkerEdgeColor = 'b';
s.MarkerFaceColor = [0 0 0];

```

```

end

```

```

guidata(hObject,handles)

```

```

title('AVAz curves')
xlabel('\phi')
ylabel('Reflectivity')

```

```

axes(handles.axes7)

```

```

for i2=1:45
    az1 = 1:1:361

```



```

Xaz = str2double(char(get(handles.edit40,'String')));

AZ = az1(1,Xaz);

ref1i(1,AZ) = A1 + (Biso1 + Baniso1*cos((AZ-1)*pi/180))^2*sin((i2-1)*pi/180)^2 + Caniso1*sin((i2-1)^2*pi/180)*tan((i2-1)*pi/180)^2;

ref2i(1,AZ) = A1 + (Biso2 + Baniso2*cos((AZ-1)*pi/180))^2*sin((i2-1)*pi/180)^2 + Caniso2*sin((i2-1)*pi/180)^2*tan((i2-1)*pi/180)^2;

s = scatter(i2,ref2i(1,AZ));

s.LineWidth = 0.6;

s.MarkerEdgeColor = 'r';

s.MarkerFaceColor = [0 0 0];

hold on

grid on

legend('\color{blue} Brine', '\color{green} Oil', '\color{red} gas', 'Location', 'NorthWest')

end

for i2=1:45 %incidence angle

ref1ii(1,i2) = A1 + (Biso1 + Baniso1*cos((i2-1)*pi/180))^2*sin((i2-1)*pi/180)^2 + Caniso1*sin((AZ-1)^2*pi/180)*tan((AZ-1)*pi/180)^2;

ref2ii(1,i2) = A1 + (Biso2 + Baniso2*cos((i2-1)*pi/180))^2*sin((i2-1)*pi/180)^2 + Caniso2*sin((AZ-1)*pi/180)^2*tan((AZ-1)*pi/180)^2;

end

for i2=1:45 %incidence angle

    for ji=1:120

        Ri(ji,i2)=0;

    end

    Ri(46,i2)=ref2ii(1,i2);

```

```

end

for i2=1:45
syni(:,i2)=conv(Ri(:,i2),rick); % convolution
end

for i2=1:45
for ji=80:1:260

syn_ni((ji+1-80),i2)=syni(ji,i2);

end

end

line(xlim(), [0,0], 'LineWidth', 2, 'Color', 'b');
grid on;

title(['AVA curves ----- Azimuth = ' num2str(AZ)])
xlabel('\theta')
axes(handles.axes8)
seisplot(syn_ni)
seisfillcolor(' ',seis)

hold on

wigggle(syn_ni)

t = colorbar('peer',gca,'Tag','colorbar2');

get(t)

ylabel(t, 'Reflectivity')

hline = reffline([0 56]);

hline.Color = 'g';

hline.LineWidth = 3;

```

```

xlabel('\theta')

ylabel('Time(ms)')

axis([0 46 0 100])

set(gca,'Ydir','reverse')


TxT.Color = 'green';

TxT.FontSize = 10;

TxT.FontWeight = 'bold';


set(handles.text83,'String','AZ')

```

B.3 BrittleAnisoMod.m

Program (MATLAB source code GUI “BrittleAnisoMod” to estimate anisotropic brittleness index BI(0°) and BI(90°) including the azimuth as an extra dimension in Rickman’s formulation.

```

function pushbutton3_Callback(hObject, eventdata, handles)

% hObject    handle to pushbutton3 (see GCBO)
% eventdata  reserved - to be defined in a future version of MATLAB
% handles    structure with handles and user data (see GUIDATA)

% syms S11 S12 S13 S33 S44 S66 l1 l2 l3 m1 m2 m3 n1 n2 n3

global data depth epsilon gamma delta PoreSpace Vsh Vp Vs rho YMDyn PR Veliso Vv Vh Ev Eh
VpFast VpSlow VpQuasi BritVertical BritHorizontal EvN EhN VvN VhN


Ev = (YMDyn - 4.*PR.*delta + 4.*(PR).^2.*(epsilon - Veliso.*gamma)) %%%%%%%%%%YOUNG
MODULUS VERTICAL%%%%%%%%%%

var1 = epsilon.*(-1).*(1 - 2.*Veliso).*delta;
var2 = 2.*Veliso.*(3 - 4.*Veliso).*(1 - Veliso);
var3 = 4.*(1 - 2.*Veliso).*gamma;
var4 = (3 - 4.*Veliso);

```

%%%%%%%%YOUNG MODULUS

$$E_{hmax} = \max(E_h)$$

$$V_{h\max} = \max(V_h)$$

ANISOTROPIC INDEX BASED ON VERTICAL AND HORIZONTAL YOUNG
MODULUS AND

POISSON

RATION

%BRTTLENES FROM VERTICAL YOUNG MODULUS AND POISSON RATIO

$$EvN = (Ev - Evmin) / (Evmax - Evmin)$$

$$VvN = (Vvmax - Vv) / (Vvmax - Vvmin)$$

%BRTTLENES FROM HORIZONTAL YOUNG MODULUS AND POISSON RATIO

$$EhN = (Eh - Ehmin) / (Ehmax - Ehmin)$$

$$VhN = (Vhmax - Vh) / (Vhmax - Vhmin)$$

$$BritVertical = (EvN + VvN) / 2$$

$$BritHorizontal = (EhN + VhN) / 2$$

$$TCv = \sqrt{(\pi \cdot Ev) / (4 \cdot (1 - Vv^2))}$$

$$TCv(isinf(TCv)|isnan(TCv)) = 0;$$

$$TCh = \sqrt{(\pi \cdot Eh) / (4 \cdot (1 - Vh^2))}$$

$$TCh(isinf(TCh)|isnan(TCh)) = 0;$$

$$TCvmin = \min(TCv);$$

$$TCvmax = \max(TCv);$$

$$TChmin = \min(TCh);$$

$$TChmax = \max(TCh);$$

$$TCvBrit = (TCv - TCvmin) / (TCvmax - TCvmin);$$

$$TChBrit = (TCh - TChmin) / (TChmax - TChmin);$$

$$BritCv = BritVertical / TCvBrit;$$

$$BritCh = BritHorizontal / TChBrit$$

```

axes(handles.axes5)

plot(BritVertical,depth,'k');hold on
plot(BritHorizontal,depth,'r');

title('ANISOTROPIC BRITTLENESS')
xlabel('Anisotropic Brittleness (unitless)')
ylabel('Depth (m)')
set(gca,'Ydir','reverse')
legend('Vertical Brittleness','Horizontal Brittleness')

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
axes(handles.axes7)
s1=scatter(BritVertical,Ev,'o')
s1.LineWidth = 0.6;
s1.MarkerEdgeColor = 'k';
s1.MarkerFaceColor = [0 0 0];
grid on
hold on

s2=scatter(BritHorizontal,Ev,'o')
s2.LineWidth = 0.6;
s2.MarkerEdgeColor = 'k';
s2.MarkerFaceColor = [0 0 1];
hold on

s3=scatter(BritVertical,Eh,'o')
s3.LineWidth = 0.6;
s3.MarkerEdgeColor = 'k';
s3.MarkerFaceColor = [0 1 0];

```

```

grid on

hold on

s4=scatter(BritHorizontal,Eh,'o')

s4.LineWidth = 0.6;

s4.MarkerEdgeColor = 'k';

s4.MarkerFaceColor = [1 0 1];

title('ANISOTROPIC BRITTLINESS&YOUNGS MODULUS')

xlabel('Anisotropic Brittleness (unitless)')

ylabel('Anisotropic Youngs modulus GPa')

legend('BritVertical Vs YMvertical','BritHorizontal,YMvertical','BritVertical Vs
YMhorizontal','BritHorizontal,YMhorizontal')

```

B.4 EFM equations of ellipsoidal inhomogeneity

Strain concentrations at the boundary of ellipsoidal inhomogeneity

Strains in the matrix at point $x = x_1 e_1 + x_2 e_2 + x_i e_i$ located at the boundary of the inhomogeneity can be represented in the following compact form (Kunin & Sosnina, 1973, Kunin, 1983):

$$\varepsilon_{ij}^{(ext)}(x) = K_{ijkl}(x)(\varepsilon_{ij}^0 - S_{klmn}\varepsilon_{mn}^*)$$

Where $K(x)$ is the *tensor of strain concentration factors*.

Replacing the dependence on x by the dependence on the outward unit normal n to the surface of the inhomogeneity, we have

$$K_{ijkl}(x) = [J_{ijmn} + R_{ijrs}(n)(C_{rsmn}^* - C_{rsmn})]A_{mnkl}$$

where

$$R_{ijrs}(\mathbf{n}) = \frac{1}{4} [n_i n_r L_{sj}(\mathbf{n}) + n_j n_r L_{si}(\mathbf{n}) + n_i n_s L_{rj}(\mathbf{n}) n_j n_s L_{ri}(\mathbf{n})]$$

$$L_{sj}(\mathbf{n}) = (n_r n_l C_{srjl})^{-1}$$

$$n_i = \frac{x_i}{a_i^4 h} \quad (i = 1, 2, 3 \text{ no sum over } i)$$

$$h^2 = \sum_{k=1}^3 \frac{x_k^2}{a_k^4}$$

Expressions for tensors **P**, **Q**, **A** and **B**

Tensors **P** and **Q** are given in this section for a number of special cases of generally anisotropic inhomogeneities of the spheroidal shape ($a_1 = a_2$) in the infinite isotropic matrix (with Lamé constants λ , G). In the case when the spheroidal inhomogeneities are isotropic (with Lamé constants λ^* , G^*), tensors **A** and **B** can be given as linear combinations of the following six tensors $T^{(1)}$, $T^{(2)}$, ..., $T^{(6)}$ (this tensorial basis was introduced, in the form only slightly different from the one used here, by Kanaun & Levin, 1994):

$$T_{ijkl}^{(1)} = \theta_{ij} \theta_{kl}$$

$$T_{ijkl}^{(2)} = \frac{1}{2} (\theta_{ik} \theta_{lj} + \theta_{il} \theta_{kj} - \theta_{ij} \theta_{kl})$$

$$T_{ijkl}^{(3)} = \theta_{ij} m_k m_l$$

$$T_{ijkl}^{(4)} = m_i m_j \theta_{kl}$$

$$T_{ijkl}^{(5)} = \frac{1}{2} (\theta_{ik} m_l m_j + \theta_{il} m_k m_j + \theta_{jk} m_l m_i + \theta_{jl} m_k m_i)$$

$$T_{ijkl}^{(6)} = m_i m_j m_k m_l$$

Where $\theta_{ij} = \delta_{ij} - m_i m_j$, δ_{ij} is Kronecker's delta and $\mathbf{m} = m_1 \mathbf{e}_1 + m_2 \mathbf{e}_2 + m_3 \mathbf{e}_3 + m_3 \mathbf{e}_3$ is a unit vector along the axis of symmetry of the spheroid.

REMARK ON THE TENSORIAL BASIS. Representation of arbitrary fourth rank symmetric tensors $\mathbf{X}$ and $\mathbf{Y}$ in this tensorial basis

$$\mathbf{X} = \sum_{k=1}^6 X_k \mathbf{T}^{(k)}$$

$$\mathbf{Y} = \sum_{k=1}^6 Y_k \mathbf{T}^{(k)}$$

makes algebraic operations convenient, since the inverse of a tensor and a product of two fourth rank tensors are readily obtained in compact form, as follows:

(a) inverse tensor is given by

$$\mathbf{X}^{-1} = \frac{X_6}{2\Delta} \mathbf{T}^{(1)} + \frac{1}{X_2} \mathbf{T}^{(2)} - \frac{X_3}{\Delta} \mathbf{T}^{(3)} - \frac{X_4}{\Delta} \mathbf{T}^{(4)} + \frac{4}{X_5} \mathbf{T}^{(5)} + \frac{2X_1}{\Delta} \mathbf{T}^{(6)}$$

$$\text{Where } \Delta = 2(X_1 X_6 - X_3 X_4)$$

(b) product of two tensors $\mathbf{X} : \mathbf{Y}$ (tensor with $ijkl$ components equal to $X_{ijmn} Y_{mnkl}$) is given

by

$$\begin{aligned} \mathbf{X} : \mathbf{Y} = & (2X_1 Y_1 + X_3 Y_4) \mathbf{T}^{(1)} + X_2 Y_2 \mathbf{T}^{(2)} + (2X_1 Y_3 + X_3 Y_6) \mathbf{T}^{(3)} + (2X_4 Y_1 + \\ & X_6 Y_4) \mathbf{T}^{(4)} + \frac{1}{2} X_5 Y_5 \mathbf{T}^{(5)} + (X_6 Y_6 + 2X_4 Y_3) \mathbf{T}^{(6)} \end{aligned}$$

Appendix C

C.1 StressMod.m

Program (MATLAB source code “StressMOD.m” based on stress field estimation using log data in shale/carbonate rocks using Atashbari et al (2012) approach.

```
[file,path] = uigetfile( {'*.xls;*.xlsx','Excel Files'}, 'Select data file')
```

```
global data Depth Den OBv Pp Porosity OBvnormalize c2g DTp PpEaton OBvG
```

```
filename = strcat(path,file);
```

```
data = xlsread(filename);
```

```
Depth = data(:,1); %Depth (m)
```

```
Den = data(:,2); %Log Density (g/cc)
```

```
Porosity = data(:,3); %Log Porosity
```

```
VPp = data(:,4) % P velocity
```

```
VSs = data(:,5) % S velocity
```

```
DTP= data(:,6); % P sonic
```

```
vcl=data(:,7); % Vclay
```

```
NPHI=data(:,8); % Neutron-Porosity
```

```
Pp=((1.*1000.*9.8*Depth.*0.000145037738)*0.00689476).*145.038
```

```
OBv=Den.*1000.*9.8.*Depth.*0.000145037738;
```

```
vptop=1700
```

```
vpmat=6500;
```

```
ccf=0.00065;
```

```
term1=(1./vpmat);
```

```
term2=(1./vptop);
```

```
term3=(term1 - term2).*exp(-1.*ccf.*Depth);
```

```
term4=term1 - term3;
```

```
NCT=(1./term4);
```

```
x1=subplot(1,2,1);
```

```
plot(NCT,Depth,'r')
```

```
hold on
```

```
plot(VPp,Depth,'k')
```

```
legend('NCT','Vp')
```

```
title('Normal Compaction Trend (NCT)')
```

```
xlabel('Velocity (m/s)')
```

```
ylabel('Depth (m)')
```

```
grid(gca,'minor')
```

```
set(gca,'YDir','Reverse')
```

```
Ppa = (OBv - Pp)
```

```
Ppb=(NCT./VPp).^1.2
```

```
Ppc=Ppa.*Ppb
```

```
PpEaton = OBv - Ppc
```

```
PR =(VPp.^2-2.*VSs.^2)./(2.*(VPp.^2-VSs.^2)) ;
```

```
c2=OBv;
```

```
c3=PpEaton;
```

```
biot = 0.4668;
```

```
UCS1=3.2807.*exp(18.202.*NPHI); %ESTIMADO DE LOS TRIAXIALES Y NPHI REGISTRO
```

```
To=UCS1./10;
```

%%% MUD

WEIGHT%%
%%

mw=[0;477.357843400000;748.804428600000;1413.66217200000;2048.86824000000;2306.684160000
00;2498.83669900000;3028.51182300000;3378.35607500000;3424.93937100000;3695.64608800000;39
81.52012000000;4017.47491200000;4187.37446500000]
dpt1=[0;305;446;842;1200;1351;1405;1676;1855;1866;1998;2104;2123;2180]

Cr=(1/76.75);%%%76.75 BULK MODULUS

%%% EFFECTIVE STRESS

%%
%

EffectiveStress=(OBv - Pp)

Deltastress=0.88;

vR1=(1-DPHI).*Cb,

vR2=((1-DPHI).*Cb) - DPHI.*Cp;

%%%PORE PRESSURE

CORRECTION%%
%%%%%%%%

PpressureNew=((vR1./vR2).*EffectiveStress).^Deltastress;

AVGDENformation=(1.9532+0.1198).*(((NCT-1584.96)./(952.5.*0.6)).^0.6);

DensPpDeviation=(AVGDENformation-1).*(1-(VPp./NCT).^2.3);

PFs = PpressureNew + ((PR./(1-PR)).*OBv);

EX=0.16;

EY=0.41;

Es=31;

```

t5=(Es*EX)/(1-PR.^2);

t6=(PR.*Es*EY)/(1-PR.^2);

t7=(Es*EY)/(1-PR.^2);

t8=(PR.*Es*EX)/(1-PR.^2);

%%%MINIMUM

STRESS%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

ShminY=((PR./(1-PR)).*(OBv-PR))+ PpressureNew + (t5) + (t6);

%%%MAXIMUM

STRESS%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

ShmaxL=((PR./(1-PR)).*(OBv-PR))+ PpressureNew + (t7) + (t8);

%%%MOVING AVERAGE

FILTER%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

num=(1/2)*[1 1];

den=[1];

YF2=filter(num,den,OBv);

plot(YF2,Depth,'r','linewidth',2)

hold on;

YF3=filter(num,den,shmin);

plot(YF3,Depth,'g','linewidth',2)

```

```
hold on;
```

```
plot(mw,dpt1,'k--','linewidth',2)
```

```
hold on;
```

```
YF5=filter(num,den,ShmaxY);
```

```
plot(YF5,Depth,'c','linewidth',2)
```

```
hold on;
```

```
YF6=filter(num,den,PpressureNew);
```

```
plot(YF6,dpt2,'color',[0.8500 0.3250 0.0980],'linewidth',2)
```

```
set(gca,'YDir','Reverse')
```

```
title('Stress Field')
```

```
xlabel('Pressure (psi)')
```

```
ylabel('Depth (m)')
```

```
grid on
```

```
grid(gca,'minor')
```