UNIVERSIDADE EDUARDO MONDLANE

FACULTY OF ENGINEERING

ACADEMIC MASTER'S IN PETROLEUM ENGINEERING

APPLICATION OF SEISMIC ATTRIBUTES CORRELATED WITH LOGS FOR RESERVOIR CHARACTERIZATION

A Dissertation by

Luís Bernardo Nhantumbo

Maputo

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RECOMMENDATION OF THE BOARD OF EXAMINERS

The undersigned certify that they have read and recommend to the Faculty of Engineering a thesis entitled“ **APPLICATION OF SEISMIC ATTRIBUTES CORRELATED WITH LOGS FOR RESERVOIR CHARACTERIZATION** “ submitted by, **LUÍS BERNARDO NHANTUMBO** in partial fulfillment of the requirements for the degree of Master of Science in **PETROLEUM ENGINEERING.**

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DECLARATION OF DOCUMENT ORIGINALITY

"I declare that this dissertation has never been submitted to obtain any degree or in any other context and is the result of my own individual work. This dissertation is presented in partial fulfilment of the requirements for the degree of Master of Science in Petroleum Engineering, from the Universiade Eduardo Mondlane".

Submitted by:

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ABSTRACT

The Application of seismic Attributes and well logs on reservoir Characterization is crucial and become an integral part of oil and gas projects, used to assist stratigraphic analysis, to define the structural or depositional environment and therefore to infer some features or properties such as petrophysical properties and rock types for decision making.

This study, started with a process of selecting seismic attributes, followed by a manual interpretation of sequence boundaries on key seismic lines. The key lines are treated as control points for the semi-automatic seismic interpretation. Finally, the sequence boundaries are semi-automatically picked by finding the shortest path defined by multiple seismic attributes. To test the effectiveness of this workflow, I used a 3D seismic data set and well logs acquired over the Dutch sector of the North Sea. Seismic attributes are different ways to look at the original seismic data, which normally is displayed in amplitudes. Generally, seismic attributes provide a better correlation between the data provided by the seismic reflection method, well log data and the geology of the study area. In this work, a seismic cube was used. The identification, interpretation and characterization of this potential hydrocarbon reservoir were possible using seismic attributes. using the powerfully software Petrel 2008.1 frequently used in the oil and gas companies for reservoir characterization. The analysis suggests a low-P-impedance zone at 680 ms time which may be due to the presence of a hydrocarbon reservoir, which shows a correlation coefficient of 0.89 and 0.91 for P-wave velocity and porosity, respectively, and show area that has P-wave velocity varying from 1500 to 2600 m/s and the porosity varying from 20 to 42%.

RESUMO

A aplicação de atributos sísmicos e perfis de poços na caracterização de reservatórios é fundamental e se torna parte integrante dos projetos de petróleo e gás, utilizados para auxiliar análises estratigráficas, definir o ambiente estrutural ou deposicional e, portanto, inferir algumas características ou propriedades como propriedades Petrofísicas e tipos de rochas para tomada de decisão.

Este estudo começou com um processo de seleção de atributos sísmicos, seguido por uma interpretação manual dos limites da sequência nas principais linhas sísmicas. As linhas principais são tratadas como pontos de controle para a interpretação sísmica semiautomática. Finalmente, os limites da sequência são escolhidos de forma semi-automática, encontrando o caminho mais curto definido por vários atributos sísmicos. Para testar a eficácia desse fluxo de trabalho, foi usado um conjunto de dados sísmicos 3D adquiridos do Bloco F3 “Offshore” Holandês do Mar do Norte. Os atributos sísmicos são maneiras diferentes de ver os dados sísmicos originais, que normalmente são exibidos em amplitudes. Geralmente, os atributos sísmicos fornecem uma melhor correlação entre os dados fornecidos pelo método de reflexão sísmica, dados de perfil de poço e a geologia da área de estudo. Neste trabalho, foi utilizado um cubo sísmico. A identificação, interpretação e caracterização deste potencial reservatório de hidrocarbonetos foram possíveis usando atributos sísmicos. usando o poderoso software Petrel 2008.1 freqüentemente usado nas empresas de petróleo e gás para caracterização de reservatórios.

Através deste estudo e possível notar uma zona de baixa impedância (P) no tempo de 680 ms, que pode ser devido à presença de um reservatório de hidrocarbonetos, e a correlação dos dados sísmicos com os dados do perfil do poço, apresenta um coeficiente de correlação de 0,89 no que tange a Velocidade e de 0,91 em termos de Porosidade, a área de estudo apresenta uma velocidade da onda P variando de 1500 a 2600 m/s e a porosidade variando de 20 a 42%

DEDICATION

This dissertation is dedicated to my family members, especially my parents Bernardo Nhantumbo and Eugenia Malando for their unconditional support.

"... tudo posso naquele que me fortalece"

(Filipenses 4.13)

LIST OF ABBREVIATIONS AND SYMBOLS

2D	Two Dimensional
3D	Three Dimensional
API	American Petroleum Institute
BSFR	Basal Surface of Forced Regression
CC	Correlative Conformity
CDP	Common Depth Point
CG	Central Graben
E	East
FSST	Falling Stage Systems Tracts
GR	Gram per cubic centimetre
g/cm3	Gamma-ray
HST	High Stand Systems Tracts
km	Kilometre
LST	Low Stand Systems Tracts
m	Meter
ms	Millisecond
m/s	Meter per Second
N	North
NM	Middle North Sea Group
NU	Upper North Sea Group
PNN	Probabilistic Neural Network
P-wave	Primary wave
RMS	Root Mean Square
SB	Sequence Boundary
SSTVD	Subsea Total Vertical Depth
s	Second

KEYWORDS

Well logs, Seismic Attributes, Reservoir characterization, Block F3

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CHAPTER I

INTRODUCTION

1.1 Introduction

The Application of seismic Attributes and well logs on reservoir Characterization is crucial and become an integral part of oil and gas projects, used to assist stratigraphic analysis, to define the structural or depositional environment for decision making.

With the proliferation of many seismic attributes, it becomes a challenge to strictly define what seismic attributes are, when they should be applied and how to classify them. These questions remain not totally answered, even for the many authors who dedicated part of their work to solve the disordered situation in seismic attributes classification (e.g., Chen and Sidney, 1997; Taner, 2000; 2001). Understanding seismic attributes is crucial for the better reconstruction of the depositional system and in identifying new hydrocarbon reservoirs.

Technological development has contributed to the improvement of the quality of results in the analysis of the characteristics of hydrocarbon reservoirs. This scientific advance was especially marked by the introduction of seismic attributes and well logs, in the reservoir's characterization, which involves subsurface description task. The purpose of acquiring and processing seismic attributes and well logs in the exploration involves mapping geologic features associated with hydrocarbon formation, generation, migration, entrapment and to characterize the static and dynamic characteristics of subsurface reservoirs. (Sanda, O. Mabrouk, D., et al.,2015).

A seismic attribute is a quantitative and qualitative measure of a seismic characteristic (Chopra and Marfurt, 2005). Seismic attributes are data or information obtained from seismic data, either by direct measurements or by logical or experience – based reasoning (Cao, J.H., et al.,2015). This led to a better geological or geophysical interpretation of the data and provide a better understanding of the geometry and physical properties of the subsurface (Chen, Q. and Sidney, S., 1997).

Seismic attributes are designed to enhance and extract information from measured seismic properties and various methodologies have been developed for their application to broader hydrocarbon exploration and development decision making. This process is a time – consuming and tedious task that involves the identification of individual boundaries and their correlation with each other. To reduce the interpretation time, algorithms and software are used generally based on seismic data (attributes) and well logs.

1.2 Research problem

With the proliferation of many seismic attributes, it becomes a challenge to strictly define what seismic attributes are, when they should be applied and how to classify them. These questions remain not totally answered, even for the many authors who dedicated part of their work to solve the disordered situation in seismic attributes classification (e.g., Chen and Sidney, 1997; Taner, 2000; 2001). The definition of seismic attributes given by Taner (1997; 2000; 2001), Barnes (2000), Chopra and Marfurt, (2005) is a blend of accepted concepts presented first. "*An attribute is an intrinsic quality of an object or person*". Therefore, in the geophysical context, "seismic attributes" "*are a way to describe and quantify a characteristic content of the seismic data*".

Seismic attributes emerged to transform the subjective and experience-based interpretation process into something less tedious, and more objective. Understanding seismic attributes is crucial for the better reconstruction of the depositional system and for identification of hydrocarbon reservoir, this refers to a sequence of geological events, processes, or rocks arranged in chronological order and this still controversial and has generated long arguments among researchers and geoscientist attempting to estimate. (Pereira, A. 2009)

Software developments, particularly Petrel P&E, have enabled researchers to study time attributes of seismic stratigraphic surfaces within the chronostratigraphic framework by using seismic data. However, the application of seismic attributes in oil exploitation identifies geomorphological changes to reconstruct depositional history has been given little to no attention to data., knowing that in reservoir characterization studies is important to always consider several variables contribution for a better description. Seismic and well log data are considered to form an integral part of the qualitative and quantitative interpretative that facilitates structural and stratigraphic interpretation.

1.3 Motivation

Attributes indicate continuous change along the time and space axis, increase size of datasets are also complicating factors and is difficult to establish a relationship between seismic response and reservoir properties (well logs), among the causes of non-uniqueness, the earth's heterogeneity and the large number and non-standardized properties including the way attributes are computed.

Today, seismic attributes are added values for structural, stratigraphic and texture analysis, and in facies and hydrocarbon reservoir properties prediction, when correctly used (e.g., Taner, 2001; Barnes, 2001; Sheline, 2005; Chopra and Marfurt, 2005). Nowadays, with the advances in seismic interpretation technology, seismic attributes analysis has become common, leading in some cases to the abuse and wrong use of this valuable tool (Sheline, 2005). Thus, we need to quantify and qualify the application of seismic data (attributes) and well logs on the reservoir characterization.

1.4 Research Objectives

1.5 Main objective

To study the application of seismic attributes correlated with logs for reservoir characterization on F3-Block North Sea continental shelf, located offshore of the Netherlands.

1.5.1 Specific objectives

1. To qualify the seismic data.
2. To estimate the seismic attributes.
3. To determine the well log properties and stablish the correlation within seismic attributes.

CHAPTER II

LITERATURE REVIEW AND THEORETICAL FRAMEWORK

2.1 Introduction

This chapter discusses the seismic data (attributes) and well logs concepts in general and briefly discuss of the methods of reservoir characterization profile.

Seismic data interpretation plays a very important role in the exploration and production stream, being indispensable to develop oil and gas prospects. The geology of the subsurface is a critical factor for the successful exploitation. Seismic attributes provide geophysicists and seismic interpreters with useful information related to the amplitude, position, and shape of a seismic waveform compared to the conventional or more traditional ways of interpreting seismic stratigraphy.

The evolution of seismic attributes is closely linked to technological evolution, essentially computational, but it also progressed gradually with the introduction in 1971 by Balch of colour seismic sections, followed by Taner analysis of complex seismic traces in 1979 and finally with the generalization of 3D seismic data (Azevedo, 2009). The attributes emerged with a main purpose: to transform the interpretation of seismic data, in a less time-consuming and more objective process. The seismic attributes allow obtaining precise and detailed information on the most varied elements present in the data, whether structural, stratigraphic, or lithological (Taner, 2001 in Azevedo, 2009) contributing to the identification, modelling and characterization of hydrocarbon reservoirs with a lower degree of uncertainty.

Considering the recent discoveries of giant hydrocarbon reservoirs, is believed that most of the largest hydrocarbon plays yet to be found are in the offshore and particular in the deep-offshore. As such, the seismic reflection method and acquisition survey geometries described in this chapter will be dealing only with marine acquisition. For a more comprehensive overview of the seismic method was presented by Sheriff and Geldart (1995) and Yilmaz (2001).

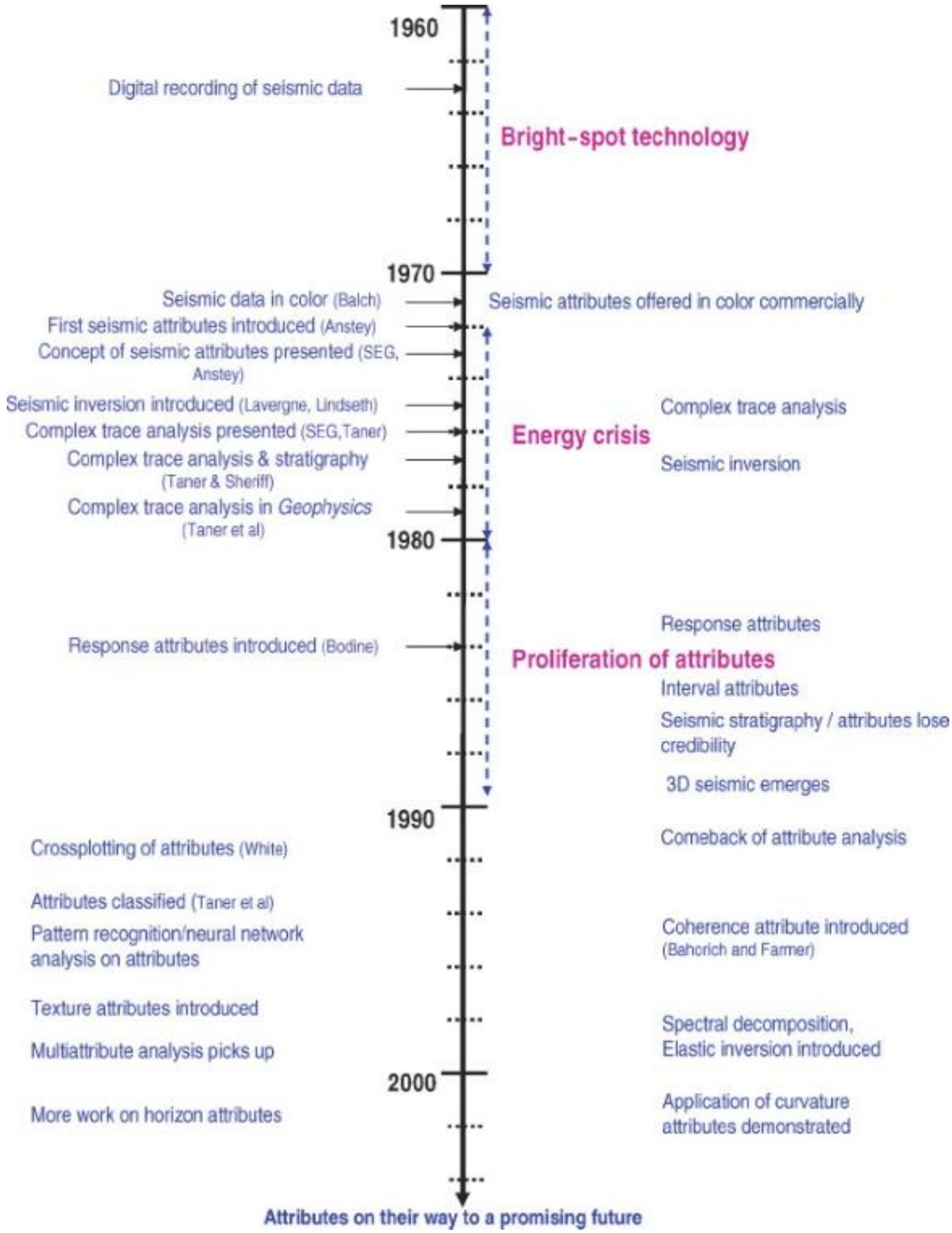


Figure 2. 1: *Timeline of the evolution of seismic attributes (Chopra & Marfurt, 2005).*

2.2 The Seismic Reflection Method

The seismic-reflection method is a powerful geophysical exploration method that has been in widespread use in the petroleum industry for more than 60 years. Since 1980, it has been increasingly used in applications shallower than 30 m, and that is the principal subject of this paper. The seismic-reflection method measures different parameters than other geophysical methods, and it requires careful attention to avoid possible pitfalls in data collection, processing, and interpretation. Part of the key to avoiding the pitfalls is to understand the resolution limits of the technique, and to carefully plan shallow-reflection surveys around the geologic objective and the resolution limits. Careful planning is also necessary to make the method increasingly cost effective relation (Don, W,.1988)

According to (The seismic reflection method is the most used geophysical technique in the oil and gas industry, as a tool for looking for hydrocarbon reservoirs, due to its high resolution even for great depths (Gomes and Alves, 2007). In fact, it can be considered that the success of oil and gas exploration and production industry is what it is nowadays due to the high quality of the seismic data acquired presently and its more accurate and better constrained interpretation (Alfaro et al., 2007). The seismic reflection method (or exploration seismology) is a remote-sensing technique which allows recording a “picture” of the subsurface with great accuracy, high resolution, and great penetration, that can be used to map geologic features associated with a petroleum system (McQuillin et al., 1986; Telford et al., 1990; Chopra and Marfurt, 2005).

Reflection seismology (or seismic reflection) is a method of exploration geophysics that uses the principles of seismology to estimate the properties of the Earth's subsurface from reflected seismic waves. The method requires a controlled seismic source of energy, such as dynamite or Tovex blast, a specialized air gun or a seismic vibrator. Reflection seismology is similar to sonar and echolocation. This article is about surface seismic surveys; for vertical seismic profiles, see VSP. (Don, W,.1988)

The selection of seismic recording equipment, energy source, and dataacquisition parameters are often critical to the success of a shallow-reflection project. It is important to carefully follow known seismic reflections throughout the data-processing phase to avoid misinterpretation of things that look like reflections but are not. The shallowreflection technique has recently been used in mapping bedrock beneath alluvium in the vicinity of hazardous waste sites, detecting abandoned coal mines, following the top of the saturated zone during a pump test in an alluvial aquifer, and in mapping shallow faults. As resolution improves and cost-effectiveness increases, other new applications will be added. (Don, W,.1988)

Exploration seismology uses the same principles of wave propagation, mainly for compressional p-waves, which travel inside Earth's layers, produced by an artificial controlled source of energy using short source-receivers offsets. Depending on the survey target, sources and receivers acquisition geometries are previously planned to maximize the imaging capacity of the seismic or attributes method for the targets under investigation (Telford et al., 1990).

In seismic reflection data, the information about the subsurface geology, physical rock properties and layers attitude, is inferred from the reflected wave travel-time between the source and its arrival at the receivers. The two-way travel-time (TWT) is defined by the time taken for the seismic waves to travel down from the source until they meet a boundary between layers with a different seismic velocity (V), density (ρ) and acoustic impedance (z; Equation (2.1)) where they are reflected and then return to the surface. The contrast between acoustic impedance is called reflection coefficient (RC; Equation (2.2)).

$$z = \rho V \tag{2.1}$$

$$RC = \frac{Z_2 - Z_1}{Z_2 + Z_1} \tag{2.2}$$

At such interfaces, the seismic rays are partially refracted, partially transmitted and partially reflected to the surface where they are detected by a group of receivers (Figure 2.2). The arrival of reflected seismic waves produces systematic variations from trace to trace.

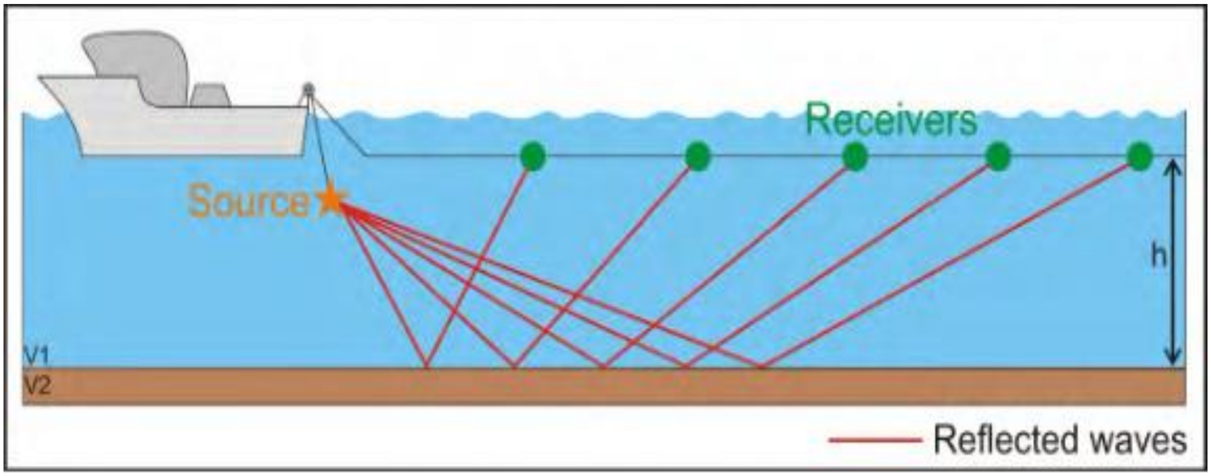


Figure 2. 2: *Diagram showing the path of the reflected seismic energy in one dimension as it travels from the source to the receivers, and it is reflected from the interface between two layers with different acoustic impedances.*

These variations are called seismic events, and if they are consistent in the recorded seismic data, they can probably be interpreted as real geological interfaces between layers with different reflection coefficients. Measuring the travel-time of the events allow to determine the attitude and location of the geological interfaces which gave rise to each reflection event. The interpretation process also considers amplitude, frequency, phase, and wave shape variations. Besides trying to identify direct hydrocarbon indicators, seismic data is most often used to identify potential structures for hydrocarbon accumulation - traps (Telford et al., 1990; Gomes and Alves, 1997).

Despite of the planned geometry, the acquisition environment, and the type of seismic acquisition (2D or 3D), receivers are disposed along a line, or along parallel lines with more than one receiver line acquiring at the same time. A seismic acquisition survey is always composed of: (a) an input source; (b) groups of receivers, which detect the reflected seismic energy (the output of the Earth) and transform it into an electrical signal, depending on the type of acquisition, receivers are disposed along a line (2D) or along parallel lines with more than one receiver line acquiring at the same time (3D); (c) amplifiers, (d) filters (e) an analogy-digital-converter (ADC) which converts the signal from analytical to digital, for recording (Telford et al., 1990, McQuillin et al., 1986).

The input source produces a previously designed pulse of energy which meets, as close as possible, certain predefined requirements such as total energy, duration, frequency content and maximum amplitude. These parameters should be set respecting the commitment of enough Earth's penetration, resolution, and good signal-to-noise ratio (McQuillin et al., 1986). Receivers should be precise enough to detect very small ground motion, due to wave propagation, and preserve the signal without adding noise.

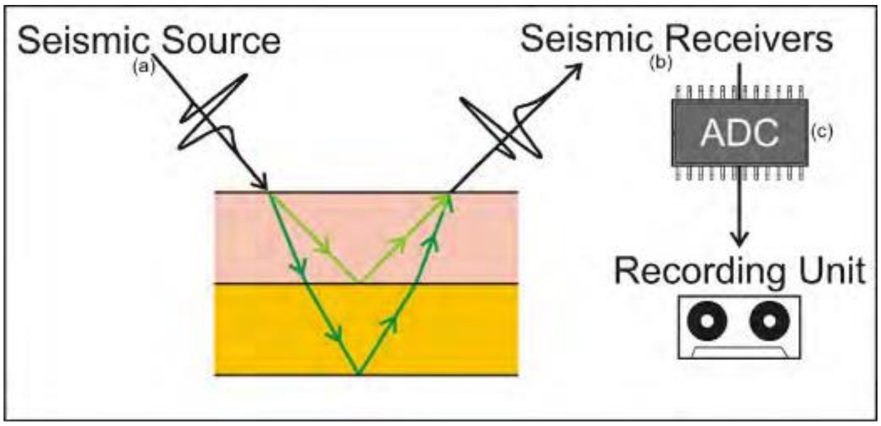


Figure 2. 3: *Schematic representation of a general seismic acquisition system. The signal is originated by the source, travels through the Earth and is received at the surface by a group of receivers.*

2.2.1. Seismic Sources

Seismic Sources Seismic sources Requirements; Principles; Onshore, offshore. Recorders Digitals recorders; Analog-to-Digital (A/D) converters.Localized region within which a sudden increase in elastic energy leads to rapid stressing of the surrounding medium. Most seismic sources preferentially generate S-waves Easier to generate (pressure pulse); Easier to record and process (earlier, more impulsive arrivals). Requirements Broadest possible frequency spectrum; Sufficient energy; Repeatability; Safety - environmental and personnel; Minimal cost; Minimal coherent (source-induced) noise.Land Source -Explosives – chemical base Steep pressure pulse. Shotguns, rifles, blasting caps;bombs, nuclear blast Surface (mechanical) Weight drop, hammer; Piezoelectric borehole sources (ultrasound); Continuous signal Vibroseis (continuously varying frequency, (Geo. 2007)

Airguns are impulsive methods that create seismic energy. An airgun is a cylindrical device which is filled with high pressure that is suddenly released into the water generating a pressure pulse. Using an array of variable size airguns (Figure 2.4) rather than using a single airgun is nowadays the standard procedure in the oil and gas exploration industry; this method allows producing a signal that matches as close as possible the theoretical desired characteristics of the input source. (Geo. 2007)

Figure 2. 4: *An array of airguns with different sizes).*

An airgun is divided into four principal components, a solenoid valve, the upper and lower chamber, which determine the size of the gun, and a double ended piston (Figure 2.5). The power of the airgun depends on the amount of high-pressured air stored in the lower chamber which is released into the water when the gun is shot. The air is injected in the upper chamber, flows through the axial opening of the piston, and is kept inside the lower chamber (Figure 2.5, on the left). When the gun is fired an electrical signal opens the solenoid valve, the high-pressured air reaches the underside of the piston producing an upward force on it. This upward movement will open the lower chamber and release the air into the water forming a bubble (Figure 2.5, right). The charging cycle starts again with the introduction of new high-pressured air inside the upper chamber which will force the piston to move downward and restart the steps described above (McQuillin et al., 1986; Sheriff and Geldart, 1995, Telford et al., 1990).

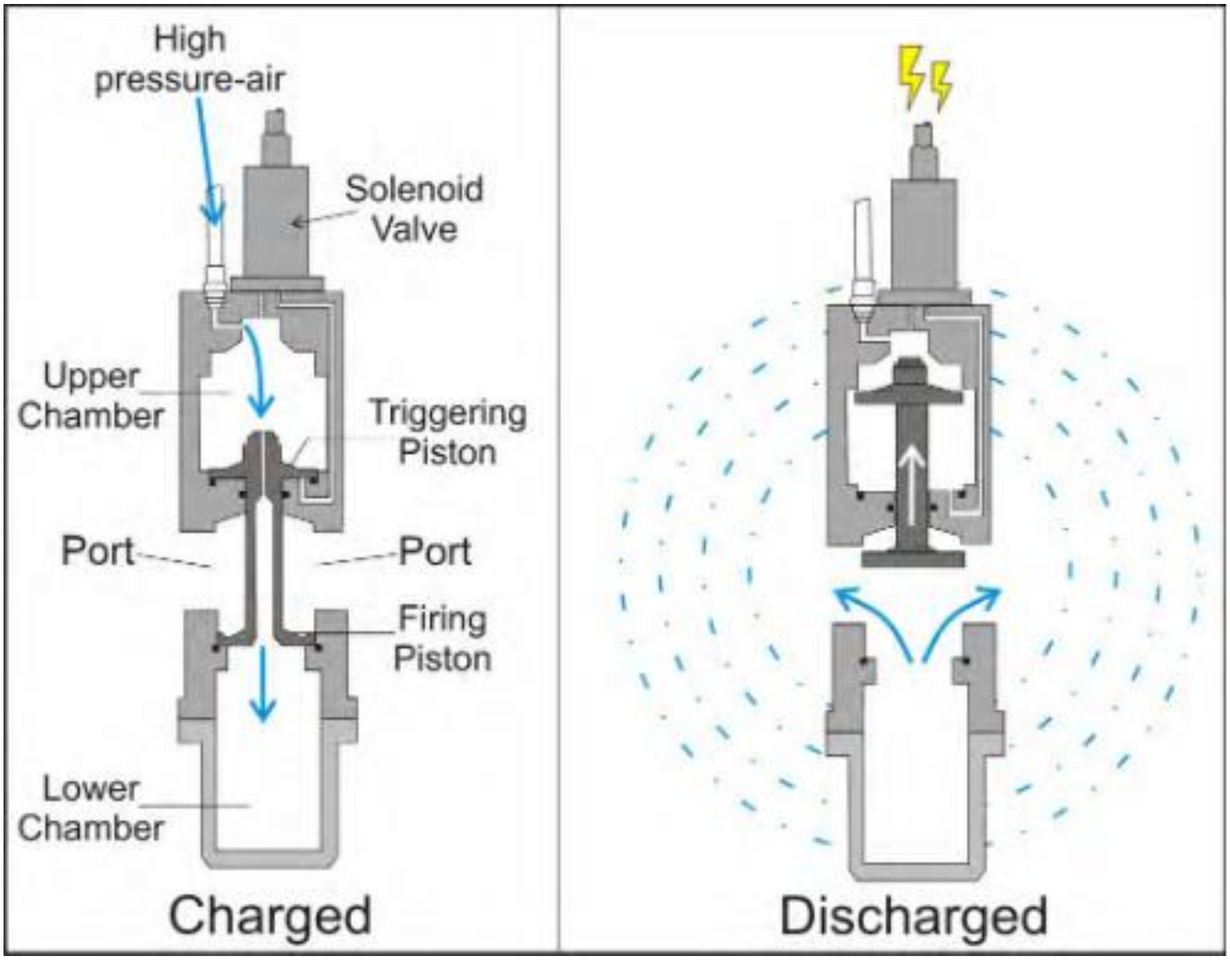


Figure 2. 5: *Schematic representation of an airgun operation.*

The biggest challenge in airguns is producing a seismic pulse as close as possible to a spike, because after the first bubble pulse, an undesired train of waves is normally created (McQuillin et al., 1986). This effect is called "bubble effect" and its origin is related to alternately moments of expansion and contraction of the air bubble formed by the shoot. When the gun is charged the lower chamber is filled with high pressured air (on the left). The airgun is then discharged by an electrical signal which opens the solenoid valve, allowing air to be released into the water while the piston moves upward producing a bubble of air (on the right).

This phenomenon will depend on the relationship between the pressured gas, the hydrostatic pressure of the surrounding water and the net force which accelerates the water outwards the bubble. When the hydrostatic pressure becomes larger than the gas pressure, the bubble originated from the shoot collapses and reduces its radius until the gas pressure inside the bubble reaches the water pressure, when the bubble starts to expand again. This oscillatory cycle will keep working until the bubble reaches the water surface. Every time a bubble collapses or expands it will produce new energy, interfering with the first and well-designed source pulse, creating an oscillatory signal (Figure 2.6; Telford et al., 1990).

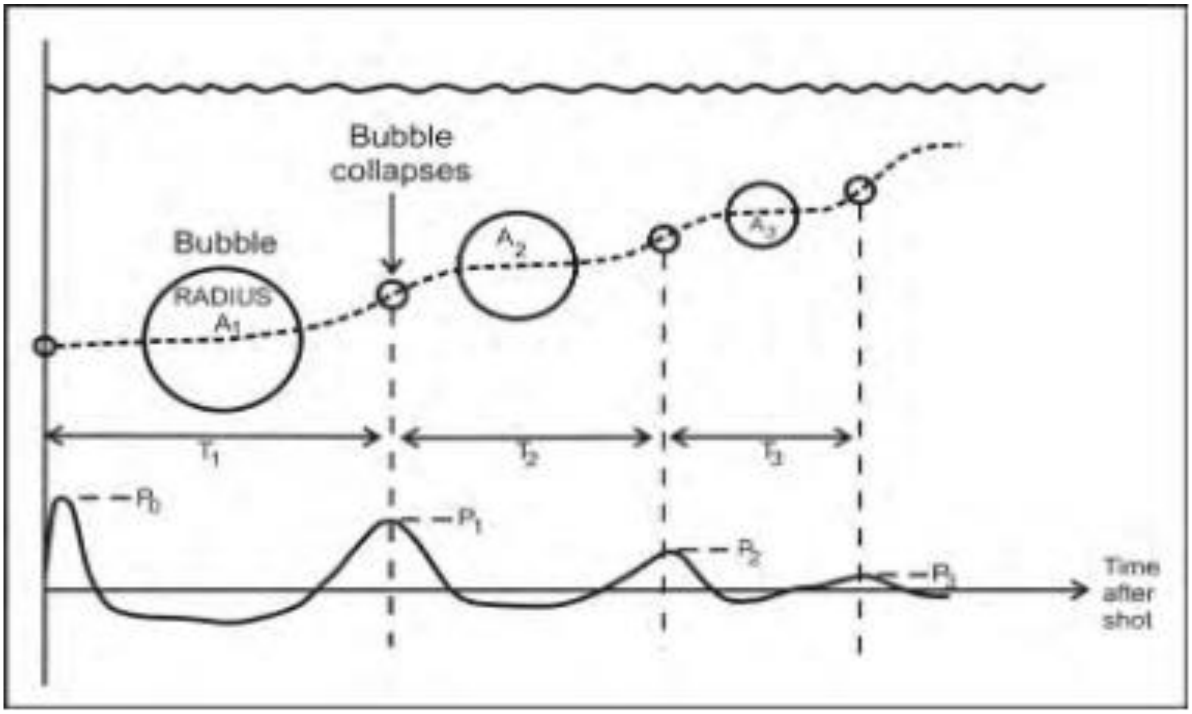


Figure 2. 6: *Representation of the bubble effect. The radius of the produced bubble when the airgun is fired is continuously expanding and collapsing until it reaches the surface creating an undesired oscillatory signal.*

Many of the acquisition seismic surveys use arrays of variable size airguns disposed in a special geometry and fired at different intervals to minimize the bubble effect. Synchronizing the firing time to align the first pressure peak will produce a cancellation of the oscillatory signal, producing a signal with frequency as close as possible to a spike pulse. Special types of airguns, called GI-guns were especially designed to minimize this effect (Sheriff and Geldart, 1995).

2.2.2. Seismic Receivers

A seismic detector measures the displacement, velocity or acceleration of material. Typically, it is an electromechanical device that responds to a mechanical input such as physical motion or pressure, and outputs an electrical signal.

On land the instruments are called seismometers or geophones. Once the sensor's spike (right) is planted into the ground, the geophone case moves with the ground while a heavy magnetic mass suspended on a spring inside the case stays stationary owing to its own inertia. The relative motion between a coil wrapped around the magnet, and the magnetic field supplied by magnets attached to the case, sets up a voltage in the coil. This voltage is passed along the wire to the recorder where it is converted to a digital signal and stored. (Geo, 2017)

Geophones are sensitive to motion only along the axis of the coil. Vertical ground motion is best detected by a orienting the coil vertically to build a vertical geophone. It is also possible to mount the spring/mass system horizontally. A combination of several sensors in different orientations allows ground motion in all three directions to be measured. (McQuillin et al., 1986).

Depending if the survey is carried on land or at sea, the receivers used are geophones or hydrophones, respectively. Standard hydrophones are piezoelectric sensors towed inside a streamer and transform the compressional p-waves into an electrical signal. Onshore, different kinds of geophones are used to detect p-waves or s-waves, depending on the survey purpose, and are normally coupled to the ground along straight lines (McQuillin et al., 1986). A streamer (Figure 2.7) is a neoprene tube where hydrophones are placed by groups in regular intervals with a total length from 6 to 8km (Alfaro et al., 2007; Telford et al., 1989). The streamer is filled with a liquid lighter-than-water (e.g., kerosene) to turn it neutrally buoyant. Connection wires in between hydrophones and from the receiver to the recording system are also included inside the streamer (Sheriff and Geldart, 1995).

Figure 2. 7: *A streamer being deployed into the water. When the vessel is not acquiring seismic, the streamer is kept onboard coiled on a reel. (Alfaro et al., 2007; Telford et al., 1989).*

A streamer is divided in several functional parts (Figure 2.8). The first component is a lead-in section which connects the vessel and the first group of hydrophones. This ensures the minimum interference from the vessel's movement in the streamer. Hydrophones are arranged in sections called "live sections" and in each section there are twenty or more hydrophones spaced approximately 1m. In terms of seismic processing the signal received at each hydrophone inside a section is summed up and is considered just one receiver group (or channel). This technique improves the signal-to-noise ratio but when there is a great component of noise acquired with the signal, it can damage the quality of the data (Alfaro et al., 2007). "Dead sections" (Figure 2.8), i.e., sections without hydrophones, are placed between live sections to give the desired length and configuration to the streamer. The last section is followed by a tail buoy equipped with positioning tools that communicate with the vessel (Figure 2.8). The buoy is used both to calculate the positioning of the streamer and to reduce the drift of the streamer due to water currents.

In intervals between channels hydrostatic pressure-based depth controllers, normally designated as "birds" are placed. These devices will induce a compensation against the upward or downward movements of the streamer to maintain it at a constant depth (Sheriff and Geldart, 1995; McQuillin, 1986).

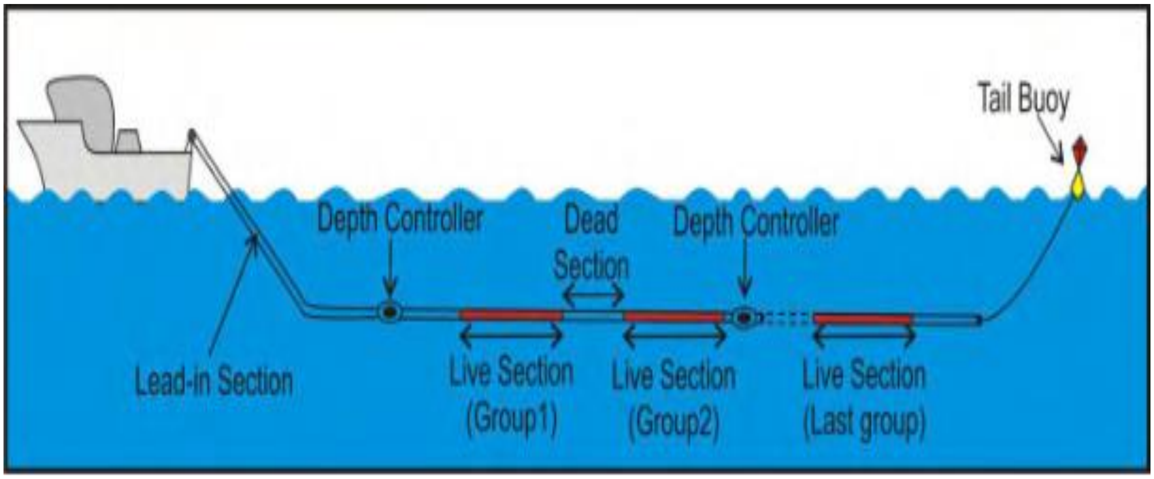


Figure 2. 8: *Schematic representation of a streamer configuration (Modified from Sheriff and Geldart, 1995).*

A stabilized streamer will reduce the noise content of the data and will ensure the right positioning of the group of channels, in depth and space, to be later corrected in the definition of the acquisition geometry, during the seismic data pre-processing stage. In addition, the towing depth will also determine the frequency component of the received signal; if a streamer is towed at less than 8m depth than the sea surface, it will better preserve the high-frequency content of the signal, but it will also increase the noise derived from weather and sea conditions.

2.3 Seismic Data

Seismic Data means data produced by an exploration method of sending energy waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation.

There are three types of seismic data: Reflection (including 2-D and 3-D) Shear wave. Refraction. Seismic data can provide a very good image of the subsurface. However, without knowing the seismic wavelet there can be many equally valid surface geologic interpretations of the actual subsurface geology. The wavelet connects seismic and well data.

The number of channels per square km (sq. km) is far higher in 3D at 2,500 than the number of channels per line km (LKM) at 250 only in 2D. This translates into a more concentrated data per block and precise information mapping (visualized as a volume/cube).

a) **Two Dimensional (2D) Seismic Data**

Two-dimensional seismic data is normally acquired along spaced straight lines at distances from each other that normally range from hundreds of meters to several kilometres. In marine seismic surveys, a single seismic vessel is used with one airgun array and a single streamer. Theoretically the content of the 2D seismic data has only information about the subsurface vertically below the acquisition path. However, the received signal has contributions of reflections from points outside the acquisition path. In terms of comparison, two-dimensional seismic sections can be considered as cross-section of a seismic volume (Yilmaz, 2001).

In the current days and due to their low acquisition costs (comparing with 3D), 2D seismic surveys are the first exploration method used in oil and gas industry, where not enough knowledge about the subsurface exists. Regional surveys are carried out to identify potential large scale hydrocarbon accumulation sites and decide about further 3D surveys parameters (McQuillin et al., 1986). To improve the signal content of the data a redundant sampling of the same reflection point is used, based on the common midpoint (CMP) reflection method (Figure 2.9; Sheriff and Geldart, 1995). The recorded seismic trace is a time-series associated with a source-receiver pair; for processing purposes this geometry needs to be transformed into common midpoint (CMP) coordinates.

For a horizontal interface, a CMP is a point at the surface located at half-offset between the source and the receiver, that is common to several source-receiver's pairs (Figure 2.9). The number of times a CMP is sampled represents the fold of the data. A CMP gather (Figure 2.9, below) is a collection of traces that share the same midpoint. This method provides enhanced data quality, suppression of multiple reflections and improved general signal-to-noise ratio, especially after stack (Yilmaz, 2001).

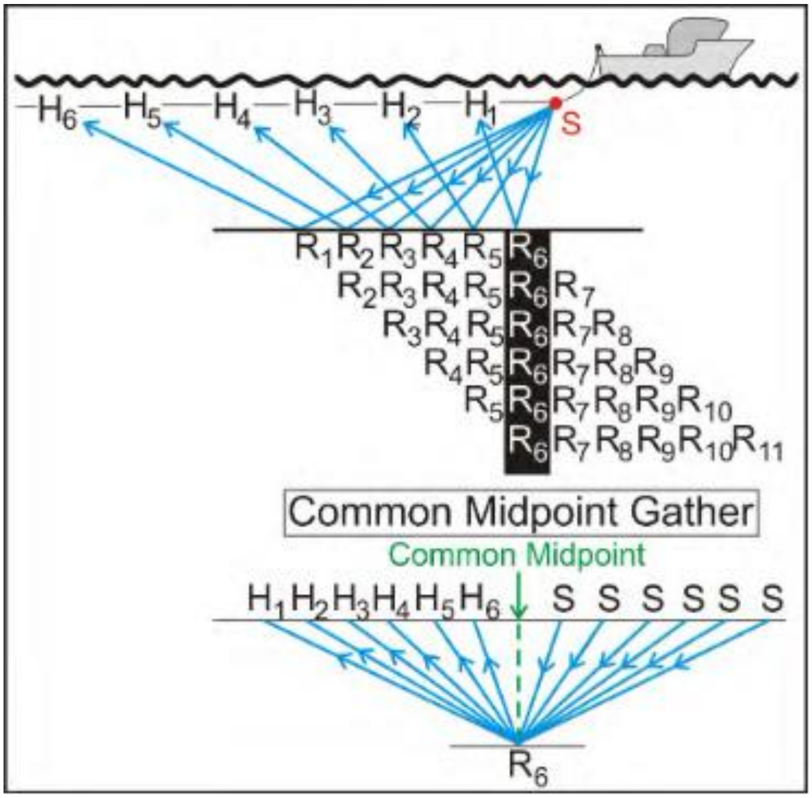


Figure 2. 9: *Seismic data acquisition. The lower part of the figure shows a six-fold coverage for one CMP location (modified from glossary.oilfield.slb.com).*

b) **3D Seismic Data**

The acquisition of three-dimensional seismic data started in 1976 (Sheriff and Geldart, 1995) and rapidly increased its importance for the petroleum industry due to its high vertical and lateral resolution even for great depths (Gomes and Alves, 2007).

Unlike traditional two-dimensional surveys which only provide information in depth along a straight line, three-dimensional seismic provides a cube with seismic data relative to three dimensions of the space (X, Y and time/depth) organized in inclines (with the same direction as the acquisition track) and crosslines (in a perpendicular direction of the acquisition path). Depending on the quality of the data in the 3D seismic volumes, the interpreter can map horizons and follow seismic events along the entire acquisition survey area and build a reliable geological model of a hydrocarbon reservoir. 3D seismic surveys have probably done more than any other modern technology to increase the likelihood of success of exploration drilling (Buia et al., 2008). In fact, interpretation of 3D seismic data benefits both exploratory wells (wildcats[1]) and development wells. The number of successful wildcats has increased in the last decades with the introduction of new acquisition and processing techniques. Development wells have also benefited, since the interpretation of three dimensional seismic data allows a better knowledge of the subsurface and the possibility to develop new solutions to improve wells productivity (Alfaro et al., 2007).

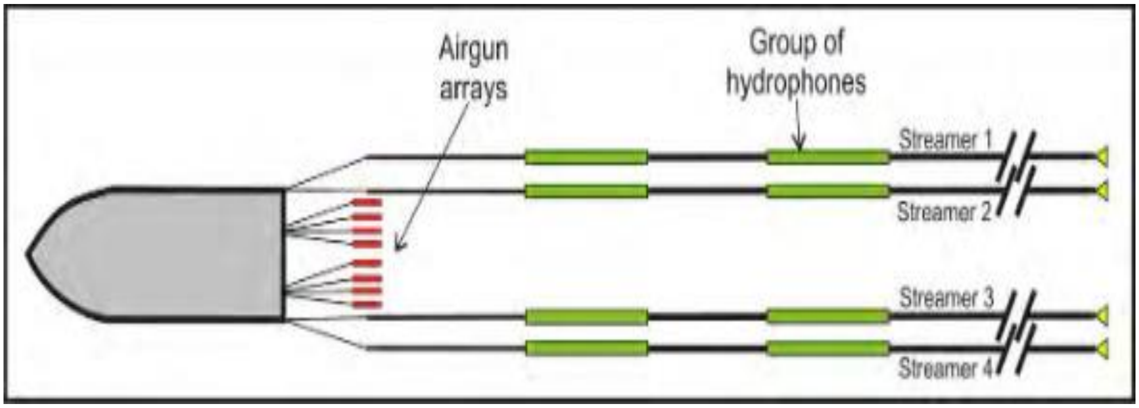


Figure 2. 10: *Schematic representation of a 3D seismic vessel configuration with 2 arrays of 4 airguns each and 4 streamers.*

In three-dimensional seismic acquisition surveys, four to ten streamers separated by 50 to 150m and airguns arrays of 12 to 18 guns that can be fired every 10 to 20 seconds at different times, are normally used. Since three-dimensional seismic acquisition is a multi-coverage method there is an immediate improvement in the signal-to-noise ratio and multiples attenuation, by sampling the same reflection, or bin[2], several times from different positions. In addition, the resulting dense sampling grid and data quality makes it possible to map not only hydrocarbon reservoirs but in some cases also assess the quality and the distribution of the oil and gas within a reservoir (Alfaro et al., 2007).

[1] A wildcat is an exploratory well in an area where there are few geological knowledge of the subsurface (glossary.oilfield.slb.com)

2 Bins are small square areas (normally 25 m by 25 m) that are treated as reflection points for the purpose of 3D data processing (Alfaro et al., 2007)

2.3.1 Seismic Marine Acquisition Surveys (3D)

A marine acquisition survey requires that the water column is deep enough (more than 10m deep) to allow freedom of movements for seismic vessels with lengths between 30 to 70m. Marine seismic acquisition is faster and consequently cheaper when compared to land surveys, since there are less non-productive time[3] (Telford et al., 1990; Sheriff and Geldart, 1995). The concept of seismic imaging is inextricably linked with the way in which the data is acquired (Amundsen and Landon, 2009). Subsurface imaging using 3D seismic surveys (Figure 2.11) is particularly successful in areas with clastic sediments.

However, problems arise, particularly in the deep-water, when imaging sediments beneath hard seafloors, salt, basalts, and carbonate layers. These limitations are caused by ray bending on the highly reflective and folded layers leading to portions of the subsurface remaining unsampled. This effect can be particularly important for seismic data acquired in just one direction. The key for a representative "picture" of the subsurface is a successful data acquisition with a 360º azimuth-offset illumination of the target area, only possible to achieve with the introduction of new acquisition geometries which consider more than one track direction (Buia et al., 2008).

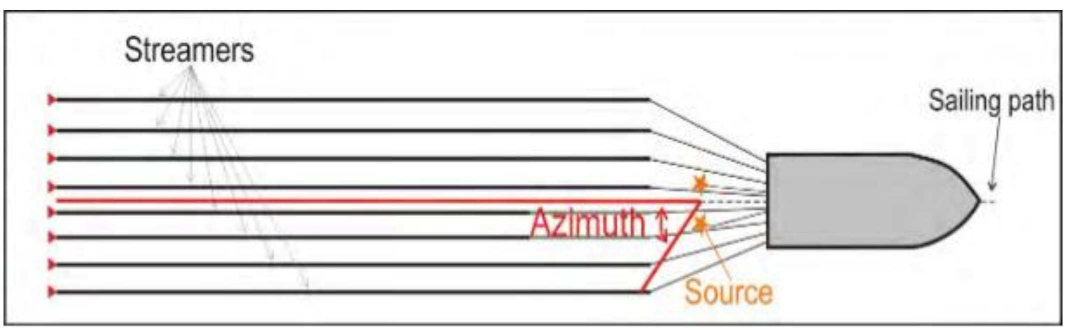


Figure 2. 11: *Schematic representation of a seismic vessel acquiring 3D seismic data, sailing in a straight path. Azimuth is the angle, at the source array, between the sail path and the considered receiver (Modified from Alfaro et al., 2007).*

3 Non-productive time is the time spend not acquiring data due to field operations. In the marine seismic acquisition sense means the amount of time a seismic vessel spends in transit from the end of one seismic line to the beginning of the next one.

a) Typical Marine Seismic Surveys

In conventional seismic acquisition surveys, the data is acquired by a single seismic vessel sailing in straight parallel lines, with opposite directions providing a coverage of about every 12.5m, with multiple streamers, over a target area (Figure 2.12). The seismic vessel is normally equipped with eight to ten streamers and a variable number of airguns and source arrays, depending on the target depth (Alfaro et al., 2008). This kind of survey has a high percentage of non-productive time represented by curved path between the end of one line and the beginning of the next. In total, non-productive time can reach 50% of the total duration of the survey, therefore increasing acquisition costs (Buia et al., 2008).

If well planned, this acquisition geometry is enough to obtain a reasonable imaging of the subsurface for almost all geological environments. Moreover, since it is a standard oil industry acquisition scheme, seismic processing flows are well known and easily applied with high effectiveness in noise reduction and improvement of the data quality. However, there are imaging limitations related to some geological contexts which cause ray bending (e.g., areas affected by intense salt tectonics) and when there are infrastructures that obstruct the acquisition path creating coverage gaps (Alfaro et al., 2007).

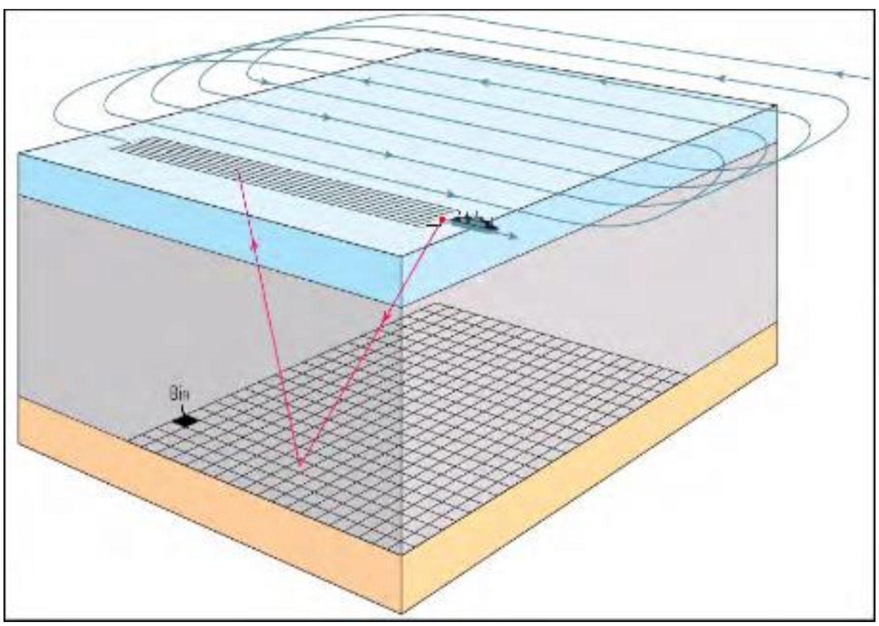


Figure 2. 12: *Schematic representation of a traditional seismic survey. The vessel sails in parallel lines with opposite directions, curved paths represent non-productive time because the acquisition system is switched off. The target area is divided in bins for the purpose of processing the data (Buia et al., 2008).*

Typical marine seismic acquisition surveys have narrow azimuth-offset coverage, just +/- 10º azimuths for far offsets (Figure 2.19) since the illumination is just in one direction and the direction of the reflected ray path will be close to the vessel track. To attenuate the lack of azimuth-offset illumination of this acquisition geometry, it should be carried out ensuring the maximum possible trace coverage per bin (Alfaro et al., 2007; Buia et al., 2008).

This conventional acquisition geometry is the mostly used acquisition method to acquire 3D seismic data worldwide. However, seismic data can easily have low quality, making the interpretation process very difficult, leading to possible incorrect reservoir prediction and characterization. Alternative seismic acquisitions geometries based on more than one sailing direction have been more recently developed to obtain more consistent and reliable 3D seismic data (Alfaro et al., 2007).

b) Wide-Azimuth Seismic Surveys

Wide-azimuth surveys (WAZ) were first introduced in the oil and gas exploration industry by BP and PGS[4] in 2001 with a testing acquisition survey in the Norwegian Sea (Alfaro et al., 2007). WAZ is a multi-vessel based method which follows the same acquisition pattern as a typical survey, in straight and parallel lines, but at least two source seismic vessels are used. The source vessels follow the recording vessel (typically with ten streamers), one behind and the other besides the streamer (Figure 2.13). Other geometries using additional seismic receiver vessels can also be applied depending on the complexity of the subsurface target (Alfaro et al., 2007; Buia et al., 2008). This method has proven improvements for large surveys in areas with great complexity and in subsalt imaging. For an effective seismic data quality, the survey should be designed considering the greatest possible distance between the source and the receiver, in a perpendicular direction to the acquisition path (crossline direction) and between consecutive acquisition lines depending on the number of involved vessels and the size of the survey area (Alfaro et al., 2007).

The wide-azimuth acquisition technique provides a general increase in coverage for all azimuths-offsets when compared to the traditional acquisition system. In fact, for near offsets it provides a full azimuth range, the optimal situation, and +/- 30º for far-offsets. Lastly, processing flows for data acquired by WAZ geometries are derived from those applied to data supplied by conventional seismic acquisition surveys, but after several basic processing steps. When compared

4 Petroleum Geo-Services

with conventional 3D data, WAZ seismic data shows less coherent noise, higher resolution, improved multiple attenuation and much better seismic reflectors continuity and interpretability, especially for those beneath salt bodies (Alfaro et al., 2007).

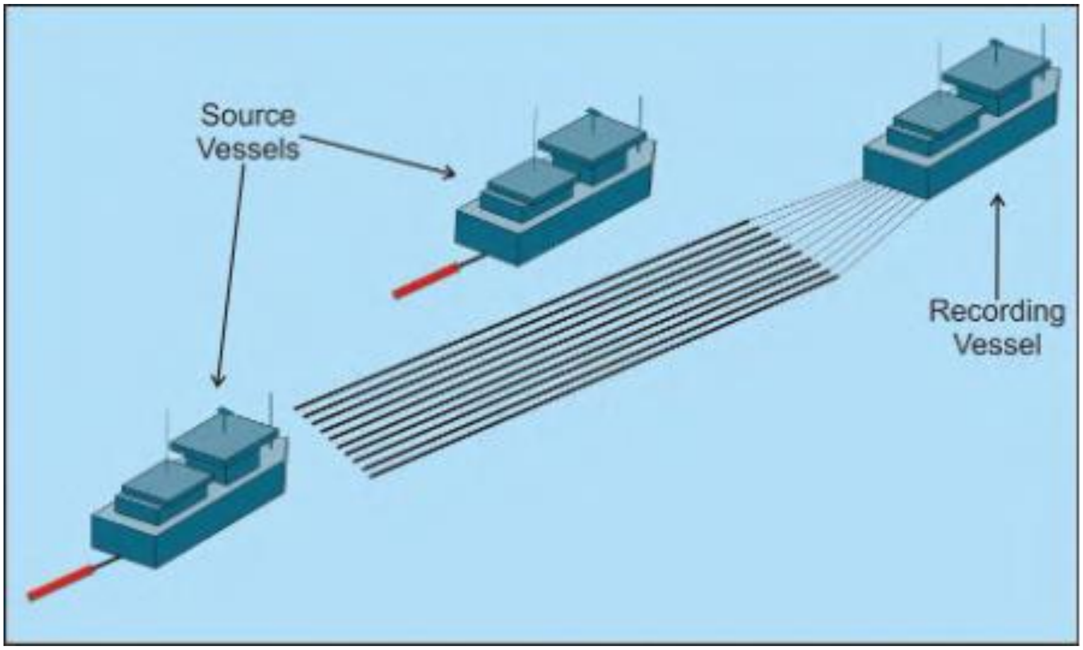


Figure 2. 13: *Schematic representation of a wide-azimuth survey. A seismic receiver vessel sails along a straight path, above the target area, followed by two source vessels sailing one behind the towed-streamer and the other besides the receivers.*

2.4 Basic Seismic Data Processing

Standard seismic processing flows are fully implemented and well known in the industry with the goal to increase the vertical resolution, to improve the signal-to-noise ratio of the data, and to display the seismic events in their correct spatial position (McQuillin et al., 1986).

A typical simple processing flow for a 2D survey is composed of a pre-processing stage, which includes: demultiplexing, trace editing, spherical divergence and geometry corrections, and a processing flow which normally includes deconvolution, CMP sorting, velocity analysis, normal moveout correction, CMP stack and migration. The processing concepts and algorithms applied in 3D seismic data processing are almost the same as those applied to 2D data. The main differences concern: quality control, statics correction, velocity analysis, migration, and the way in which reflective points are considered for seismic processing purposes. In 3D seismic data, reflection points are designated as "bins" instead of common midpoints (CMP; Yilmaz, 2001). The seismic data is sometimes recorded in a multiplexed way in which samples from the same time interval from different shots are recorded consecutively. In such cases, the first step of the pre-processing stage consists of demultiplexing, to convert the data into a suitable and organized file format for processing purposes. In oil industry, the conventional standard for seismic files exchange is SEG-Y.

The data is then edited to detect and correct abnormal traces with high noise content or inverted polarity. If basic filtering is not enough to repair the noisy trace they should be eliminated since their contribution will decrease the signal-to-noise ratio. Basic filtering is also applied to all data to reduce the characteristic low-frequency noise originated from bad weather and/or sea conditions and by undesired movements of the streamer (Yilmaz, 2001).

The spherical divergence correction applied next is a gain correction function to compensate the amplitude effects of spherical wavefront divergence. Finally, the data is corrected for the acquisition geometry with the positioning of shots and receivers inserted into the trace headers. This simple step is one of the most important in the processing flow and many of the problems that arise at later stages are originated by geometry definitions errors.

Deconvolution is then applied to compress the wavelet shape in the data, recover high-frequencies, attenuate reverberations, and short-period multiples, increasing the vertical resolution of the reflectors and normalizing the frequency spectrum of the data. Ideally, the recorded seismic trace is a convolution of the seismic wavelet, which travels from the source through the subsurface, with the reflection coefficient series, derived from the properties (density and seismic velocity) of the different rock layers crossed by the seismic energy. Deconvolution tries to undo this natural convolution process, by eliminating the source signature and derived multiples, obtaining the reflection coefficient series. However, the received signal does not contain only information about the wavelet signature and the Earth's impulse response. In fact, there many other components such as noise and limitation on sources and receivers that make it impossible to obtain the real impulse response of the Earth (Yilmaz, 2001).

The Normal Moveout (NMO) correction is then applied to data sorted by CMP (a CMP gather) using a previously created velocity field. This correction removes the source-receiver offset effect in a non-dipping seismic reflector, assuming that the reflection travel-time, which is a function of offset, follows a hyperbolic trajectory. Since reflections arrive first at nearest offsets and later at far offsets, the greater the source-receiver offset the larger the delay observed. In the NMO correction, seismic events corresponding to seismic reflections are flattened across the offset range to remove the previously described effect (Figure 2.16; Yilmaz, 2001). NMO is a dynamic correction since corrections will decrease with the increase in two-way-time and the increase in sound speed of rocks (Robinson et al., 1986).

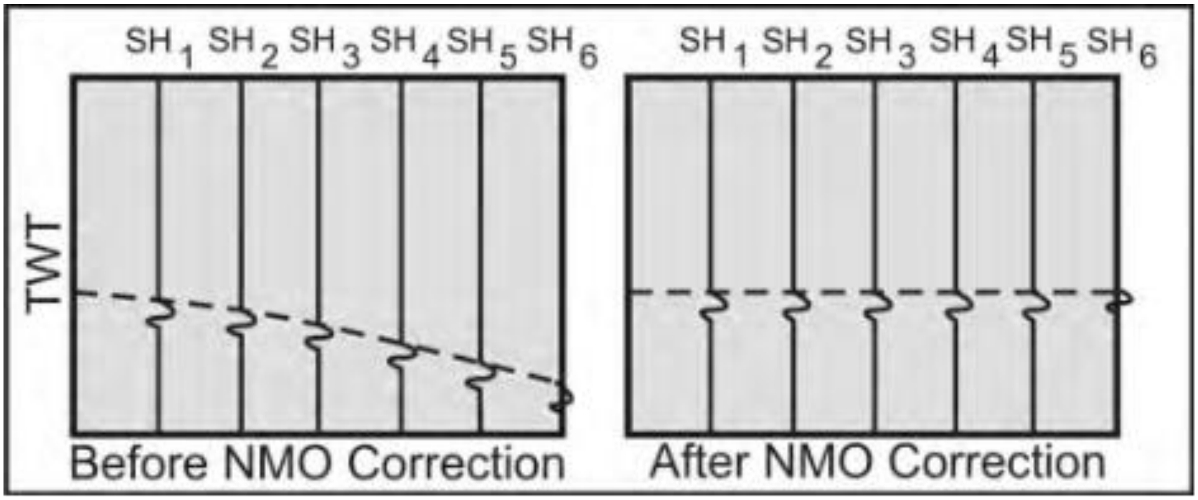


Figure 2.14: *Diagram of six traces displayed before and after normal moveout correction (from glossary.oilfield.slb.com).*

After a detailed velocity analysis, the resulting velocity field is applied for NMO correction and to stack the data. Stacking consists of summing the traces which belong to a CMP location into just one trace after NMO correction (Figure 2.17). The output data will have reinforced reflections, since noise is theoretically random and when summed tends to cancel, increasing the signal-to-noise ratio (glossary.oilfield.slb.com). The classic processing flow normally finishes with a migration algorithm. This process attempts the repositioning of the seismic reflections in their supposedly true subsurface position in depth.

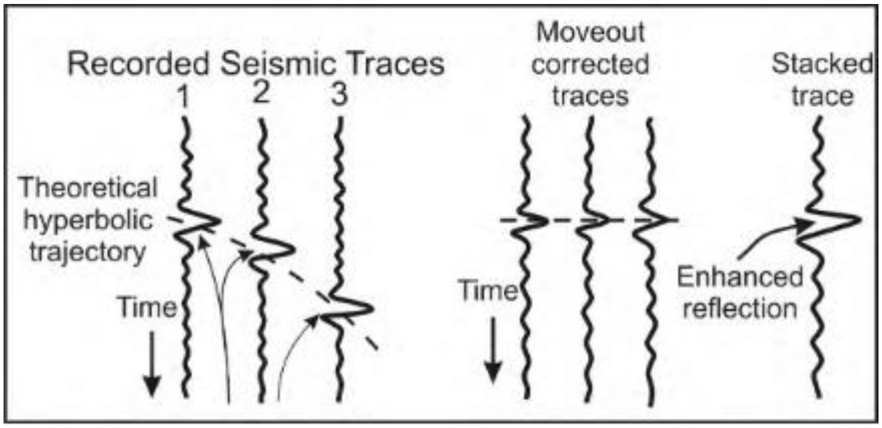


Figure 2. 15: *Data is organized by CMP which are corrected for the normal moveout effect and finally stacked to improve data quality (glossary.oilfield.slb.com).*

With a proper migration, based on a realistic velocity model, most of the diffractions within the data are collapsed. Migration has proven results for improving seismic interpretability and mapping of complex structural areas intensely folded and faulted. This processing algorithm also increases the spatial resolution of the data. For three-dimensional seismic data, 3D-migration algorithms are used.

Another way of applying a migration algorithm is before stack (pre-stack migration). Pre-stack migration is an intensive time-consuming and a heavy computation process which allows to imaging reflectors with abrupt variations of lateral velocities, with non-hyperbolic reflection events, conflict dips, and steep discontinuities. The algorithm is applied trace to trace at each CMP location, instead of being applied to the stacked data. Pre-stack migration will solve seismic imaging below salt bodies which is especially important in hydrocarbon migration and accumulation detection. All the processing steps should be quality controlled through seismic cross-sections displays to ensure that the quality of the data is not diminishing (Yilmaz, 2001).

2.5 Interpretation of 3D Seismic Data

Structural seismic interpretation is directed toward the creation of structural maps of the subsurface from the observed three-dimensional configuration of arrival times. Seismic sequence stratigraphic interpretation relates the pattern of reflections observed to a model of cyclic episodes of deposition.

Seismic interpretation is the last stage in the oil and gas industry to prospect and correctly identify hydrocarbon reservoirs on properly migrated seismic cubes. Without a consistent interpretation, the seismic data itself is useless (Robinson et al., 1986). Seismic data interpretation is an exhaustive data analysis process. Nowadays there is a lot of geological information associated with a seismic volume, which should be considered. This large amount of information increases the time consumption but, if well correlated, reduces the uncertainty to build a reliable geological model (Yilmaz, 2001).

The interpreter must combine the various components of the dataset (e.g., 3D seismic cube, 2D lines and well log data) to recognize seismic patterns that can give clues about potential hydrocarbon accumulations sites, depositional environments, and the structural geology of the area. This recognition is often based on comparisons between the data and a mental database created by the interpreter's experience. As such many people consider the interpretation process as something in between a science and art (Chopra and Marfurt, 2005).

The interpretation is done visually and interactively, in powerful workstations, over vertical seismic sections, in inline and crossline directions, and in horizontal seismic sections called horizontal time slices. Available interpretation software allows the manipulation and visualization of seismic data together with well log data and allows correcting possible mis-ties. This combined visualization allows associating seismic reflectors to boundaries of known lithological layers (Robinson et al., 1986). Identified features such as faults and key seismic reflectors (called horizons), are interpreted based not only in the travel-time but also in the amplitude content, with the objective of building a reliable geologic model (Yilmaz, 2001b).

Direct hydrocarbon indicators (DHI) in seismic data are not as common as often assumed. Only in few datasets show reflections which can be unequivocally interpreted as DHIs. The interpreter will therefore mainly be looking for structures, both tectonic and stratigraphic, that can potentially hold hydrocarbon accumulations (e.g., faults and antiforms; Gomes and Alves, 2007). From seismic data alone it is not possible to unambiguously identify lithology sequences or the fluid content filling the pore spaces. This information is normally achieved with the use of modelling algorithms, well log data and more recently (Robinson et al., 1986) using seismic attributes (Chopra and Marfurt, 2005). In fact, seismic attributes are used as a starting point or complement in the interpretation process.

A careful interpretation of 3D seismic data allows accurately mapping geological features, defining the structural geology, and inferring about lithological variations and their distributions, thereby characterizing the respective depositional systems in the survey area. A fully understanding of the study area is the key for success in oil and gas exploration and production industries.

2.6 Seismic Interpretation in Petrel (3D)

Petrel Structural Interpretation improves the understanding of structure and delineation of fault and fracture networks through various advanced edge detection and illumination attributes.

it addresses the need for a single application to support the ‘Seismic-to-Simulation’ workflow reducing the need or a multitude of highly specialized tools.Petrel is used to interpret seismic data Perform well correlation Build reservoir model Calculate volumes(slumbeger, 2012)

Produce maps pretation software tends to be easy-to-use providing several automatic algorithms to help the geoscientist in the geophysical interpretation process. In the seismic attribute’s domain, new software solutions have large attributes libraries being able to compute and display them, on-the-fly, even for large amounts of three-dimensional seismic data. These combined factors introduced a new paradigm in seismic interpretation: the possibility of creating different geological models, in a faster and reliable way, which is associated with the increase in quality of seismic data, led to optimized well design and location (Chopra and Marfurt, 2005).

2.6.1. Seismic – to – Simulation software, Petrel 2008.1

Petrel has been developed by Schlumberger since 1996 and many upgrades have been done from version to version to improve algorithms and give an effective response to the customers’ needs. It unites geosciences and reservoir engineering domains to work together allowing to “think critically and in a creative way” about the modelled hydrocarbon reservoir. Companies can increase profits by reducing the uncertainty and time consumption of data analysis, interpretation, and modelling, while experiencing the different Petrel modules (Figure 2.18; Schlumberger, 2007, 2008).

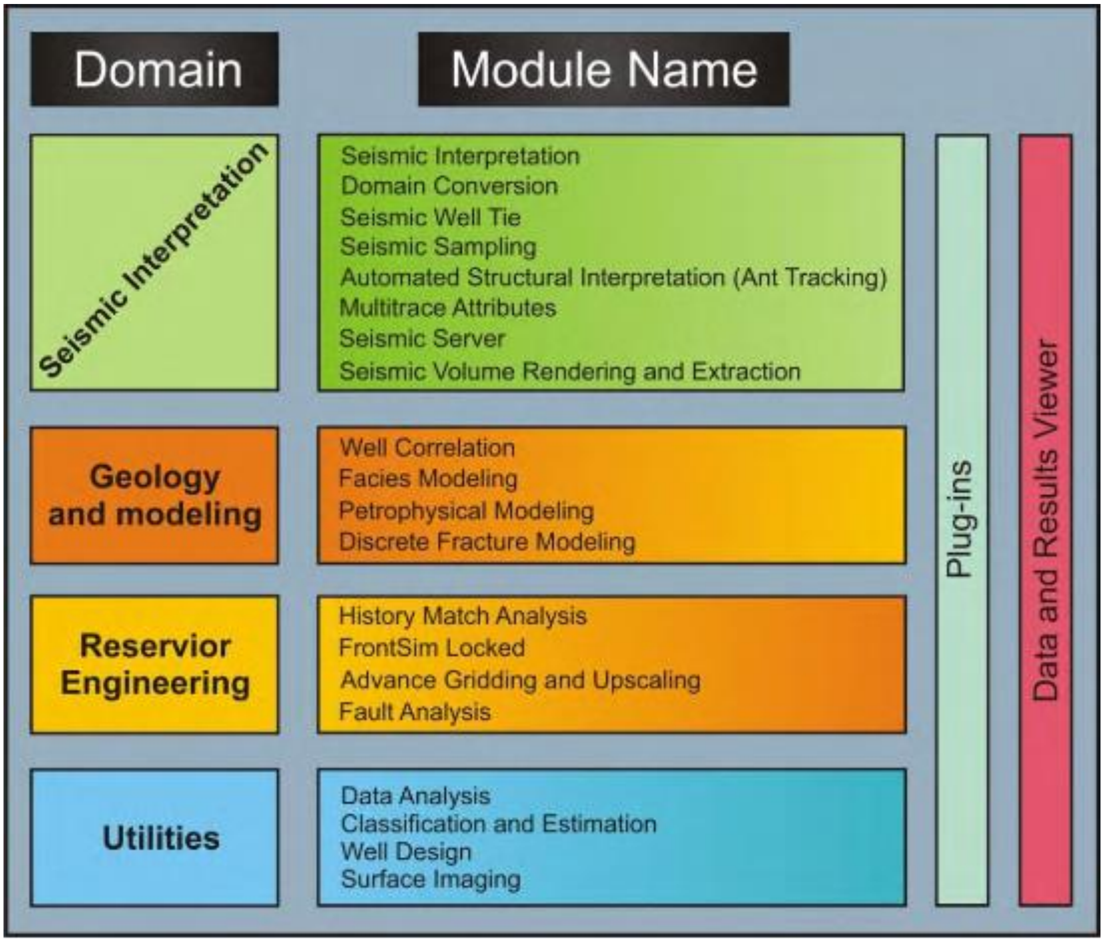


Figure 2. 16: *Petrel 2008.1 module dependency map (Pereira, G,.2009_*

2.7.1 Classification of Seismic Attributes

With the increasing interest on seismic attributes and their large number and diversity it now becomes necessary to catalogue them into different classes. Many proposals have been put forward with the aim of classify seismic attributes in a tight, strict, and intuitive way, based on both the input and the expected result. Unfortunately, new attributes appear every day and algorithms of well-known attributes can be improved since sometimes they give unexpected results.

Taner et al. (1994) were the first to introduce a coherent and real classification for seismic attributes. They created two general categories for seismic attributes: geometrical and physical. Geometrical attributes enhance geometrical characteristics of the input data such as: dip, azimuth, and continuity. Physical attributes are related to physical properties of the subsurface which are inextricably connected to the lithology. This family of attributes corresponds to attributes derived from amplitude, frequency, and phase components of the trace. These two categories can further be divided into pre-stack and post-stack, depending on the data processing step from which they have been computed.

Brown (2001) proposed to classify attributes using a tree structure with branches for time, amplitude, frequency, and attenuation, with each branch being further divided in pre-stack and post-stack attributes. Time attributes provide information about structural geology while amplitude attribute give information on stratigraphy and reservoir properties. The Chen and Sidney (1997) classification divides attributes in two main groups: one based on wave kinematic/dynamics, and the second group based on geologic reservoir features; further sub-divisions depend on where the attribute is extracted and on the expected output.

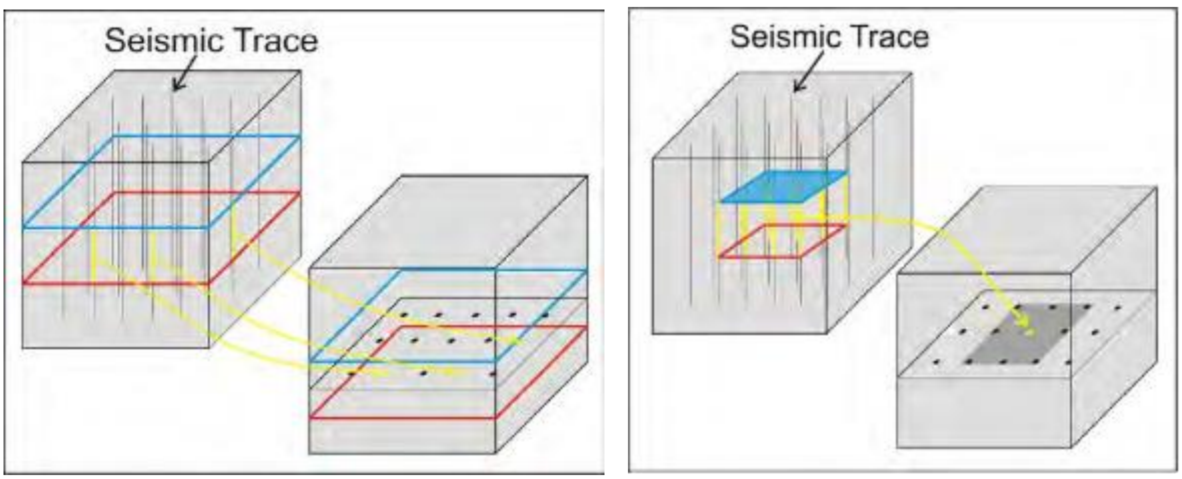
More recently, Chopra and Marfurt (2005) based on classifications from other authors, proposed a new classification for seismic attributes. The classification divides attributes into general, specific, and composite. General attributes comprise seismic attributes which measure geometric, kinematic, dynamic, or statistical features derived from seismic data. They are related either to the physical or morphological character of the data since they represent the response of a specific lithology. Therefore, they can be generally applicable to different geological environments with expected similar outputs. Specific attributes are less correlated to the lithological character of the input data and therefore cannot be extrapolated to similar geological environments since their response is intrinsic of specific hydrocarbon reservoir properties. Composite attributes include sums, products, or other combinations of more fundamental general attributes.

Petrel 2008.1 does not follow any of these classification schemes, as discussed before. It uses a new and more user-friendly classification for seismic attributes. Attributes are first divided into volume and surface attributes, depending on the input data, and then into libraries. Each library groups attributes which will enhance similar features.

2.7 Volume Attributes

Volume attributes are computed from processed seismic cubes or from previously computed attribute volumes which are extracted, depending on the mathematical algorithm, trace by trace or considering a group of traces (multi-traces). The extraction is performed over a user-defined fixed window, where two horizontal time slices are defined as upper and lower boundaries.

The single-trace method is applied when the computation algorithm operates in each trace separately between a vertical fixed window.



(a) (b)

Figure 2. 17: *Seismic attributes can be generated (a) trace by trace or (b) using a collection of multitraces. Blue and red squares represent the upper and lower time slice boundary respectively. Traces from where the attributes were extracted are represented in yellow and will be saved in a time slice placed in a central position in the computation window (modified from Chen and Sidney, 1997).*

Attribute extraction is done within the user-defined window length in a random position, inside the seismic volume. The final attribute volume is the result from repeating the attribute extraction, with the same vertical range, for different times and spatial positions, and then stacking the resultant slices. Multi-trace seismic attributes are also computed inside a fixed vertical window with user-defined limits. In this case, besides the vertical range, the user must define a bound in the number of traces that will be used to the attribute extraction, according to a mathematical algorithm. Like in the single-trace method, the output volume is the result of stacking all the time slices where the attribute computation was kept from each window position in space and time (Figure 2.21; Chen and Sidney, 1997).

2.8 Structural Attributes Library

The *Structural Attributes* library contains a collection of attributes. They are mainly used to isolate and enhance local structural variations in the seismic reflection patterns. In other words, structural attributes detect edges, compute the local orientation, and dip of seismic reflectors and enhance seismic event continuity parallel to the estimated bedding orientation. In structural attributes, an edge is defined as a discontinuity in the horizontal amplitude continuity within the seismic data, that can correspond to real faults and/or fractures.

2.9 Stratigraphic Attributes Library

Stratigraphic Attributes comprise attributes related to the identification of stratigraphic sequenc es, lateral and vertical variations of lithologies, structural orientation measurements, frequency deco -mposition and facies distribution.

2.10 Surface Attributes

A surface attribute is the value of an attribute relative to a single horizon and an interval window, between two horizons or within a constant time window. It can be computed in *Petrel* using the "*Surface Attributes*" processes under "*Geophysics*". Petrel 2008.1 has fifty surface attributes divided into four areas depending on the applied algorithm: *Amplitude*; *Statistical*; *Signal Shape* and *Measurable Interval*. In *Petrel*, surface attributes can only be computed in surfaces built from horizon interpretation.

Seismic Stratigraphic Analysis Sequence stratigraphy is the sequence, which is a "relatively conformable succession of genetically related strata bounded at the top and base by unconformity or their correlative conformities (Mitchum et al., 1977)." Seismic sequence analysis defines seismic sequences and systems tracts by identifying discontinuities recorded in reflection termination patterns. The analysis starts with establishing geometric relationships of seismic reflections on seismic profiles. Aggradation, progradation, and retrogradation are the three general stacking patterns used to distinguish between different depositional systems. Sequence boundaries and other major surfaces are identified based on seismic reflection terminations such as onlap, downlap, toplap, and truncation. Well logs provide high resolution vertical stratigraphic data. Integration of seismic and well log data provides more accurate stratigraphic models of the sedimentary fill. The well log sequence analysis performed in this study is based on GR logs response from available wells. GR logs measure the radioactivity of rocks and are commonly used as a good proxy for grain size in siliciclatic systems (Van Wagoner, 1991). Abrupt changes in GR logs responses are commonly related to sharp lithological breaks associated with unconformities and sequence boundaries (Krassay, 1998). Variation patterns of GR logs indicate changes in the stacking patterns of sedimentary facies. GR log readings can be classified into upward decreasing, constant or upward increasing. prograding, aggrading, and retrograding systems, respectively."

Gamma-ray logs record photons of gamma radiation received by a detecting crystal over a specified time period. Gamma radiation is emitted during the radioactive decay of uranium , thorium , and elements of their decay series, and from the decay of the unstable isotope of potassium , 40K

Gamma ray logging is a method of measuring naturally occurring gamma radiation to characterize the rock or sediment in a borehole or drill hole. It is a wireline logging method used in mining, mineral exploration, water-well drilling, for formation evaluation in oil and gas well drilling and for other rela The Gamma log is used to record the naturally occurring radiation found in the surrounding borehole rocks from three primary isotopes: Potassium-40 (K), Thorium (Th), and Uranium (U). Clays have the highest concentration of these radioactive isotopes; hence the Gamma log is also known as the clay log, or shale logted purposes.

Gamma Ray The radioactivity of rocks has been used for many years to help derive lithologies. Natural occurring radioactive materials include the elements uranium, thorium, potassium, radium, and radon, along with the minerals that contain them. There is usually no fundamental connection between different rock types and measured gamma ray intensity, but there exists a strong general correlation between the radioactive isotope content and mineralogy. Logging tools have been developed to read the gamma rays emitted by these elements and interpret lithology from the information collected.

Conceptually, the simplest tools are the passive gamma ray devices. There is no source to deal with and generally only one detector. They range from simple gross gamma ray counters used for shale and bed-boundary delineation to spetral in clay typing and geochemical logging. Despite their apparent simplicity, borehole and environmental effects, such as naturally radioactive potassium in drilling mud, can easily confound them. The corresponding grain size changing patterns are interpreted as an upward increase, constant or upward decrease. "In deltaic systems, (petrowiki, 2009).

Sonic Log- Sonic logs rely on the properties inherent in Snell's Law to propagate sound from a logging tool through the rock to receivers located on the same logging tool. Sonic logs require a fluid filled borehole to operate properly. Modern logs can make most measurements in both open and cased holes.

Sonic log produces data which illustrates P-wave travel time versus depth and is recorded as microseconds per foot (ms/ft). This data provides information about how fast acoustic waves travel through rock. Wave propagation which produces the P-waves in sonic logs follow properties and demonstrates how waves travel through different interfaces or rock layers in the subsurface. Waves will propagate and can be a result of several situations. Some degree of absorption will affect waves, turning the mechanical energy into heat.

Density log- The density log measures electron density by detecting gamma rays that undergo Compton scattering. The intensity of scattered gamma rays is proportional to electron density. Electron density is the number of electrons in a volume of the formation and is proportional to bulk density

CHAPTER III

DATA AND METHODOLOGY

3.1 Introduction

This chapter presents the data and Methodology, which involve all the principles behind for the research, and processed results can also be visualized in the research methods time step.

1.6 Study Area

The North Sea continental shelf, located offshore of the Netherlands is divided into geographical zones described as F3 block, within these zones there are smaller areas marked with numbers. These areas is a rectangle of dimensions 16 km x 24 km, represented in Figure 1.1. In 1987, the F3 block 3D seismic survey was conducted to identify the geological structures of this area and to search for hydrocarbon reservoirs.(Kabaca, E, 2018)

The present study focuses on the rock formation called the North Sea Group, assembled durin g the Tertiary and Quaternary period. The stratigraphy of the survey area is recorded by the composite well log reports of the Wells F02-1, F06-1, F03-1, and F03-4.
F3 Block seismic data and well logs data from North Sea, are used in this study Due to the unavailability of data from companies that currently operate in the national territory (Mozambique), F3 Block are data available on the internet, with the purpose of being used by researchers and students.

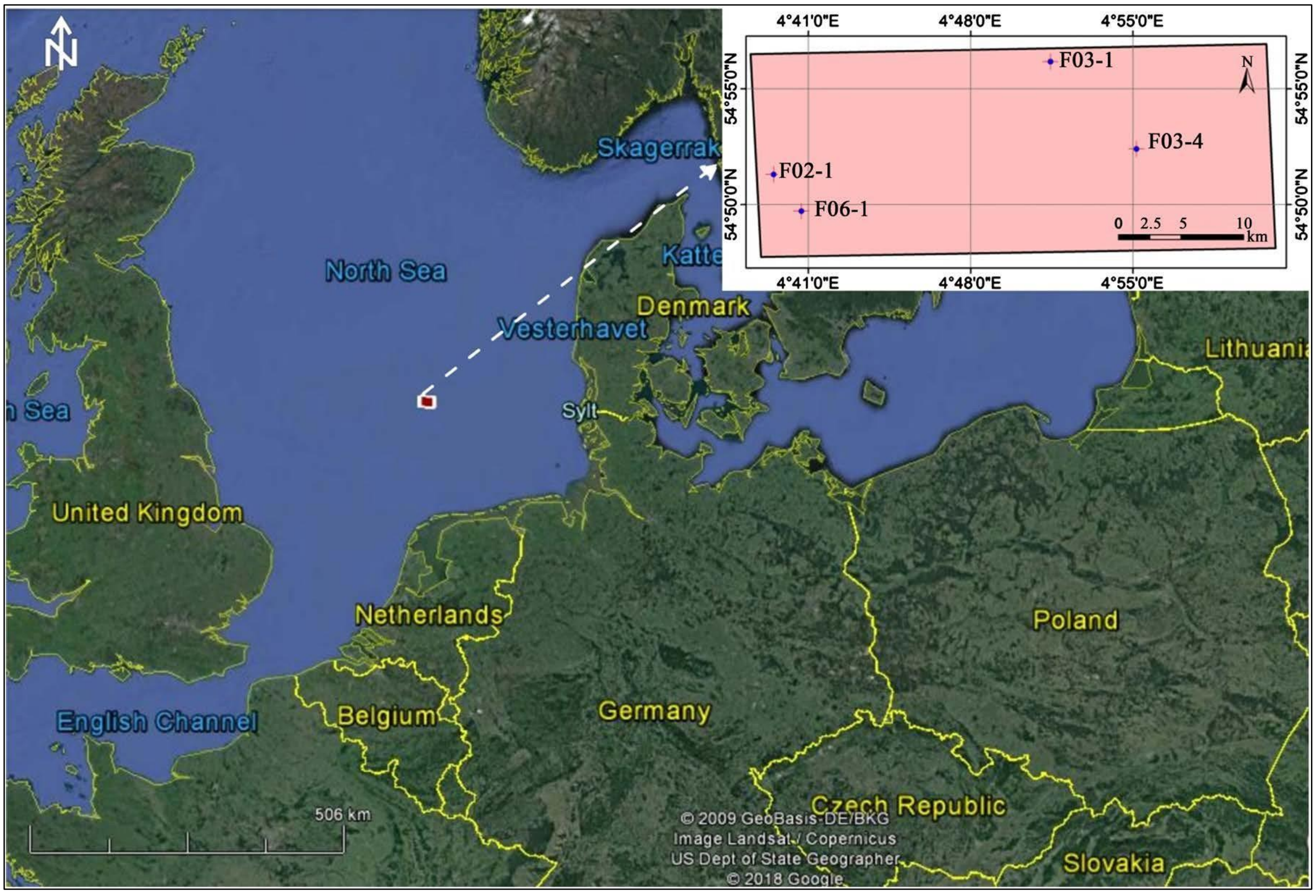


Figure 3. 1: *Location of the F3-Block in the North Sea (Dutch sector) with its wells (F02-1, F03-1, F03-4 and F06-1) presented on Google Earth.*

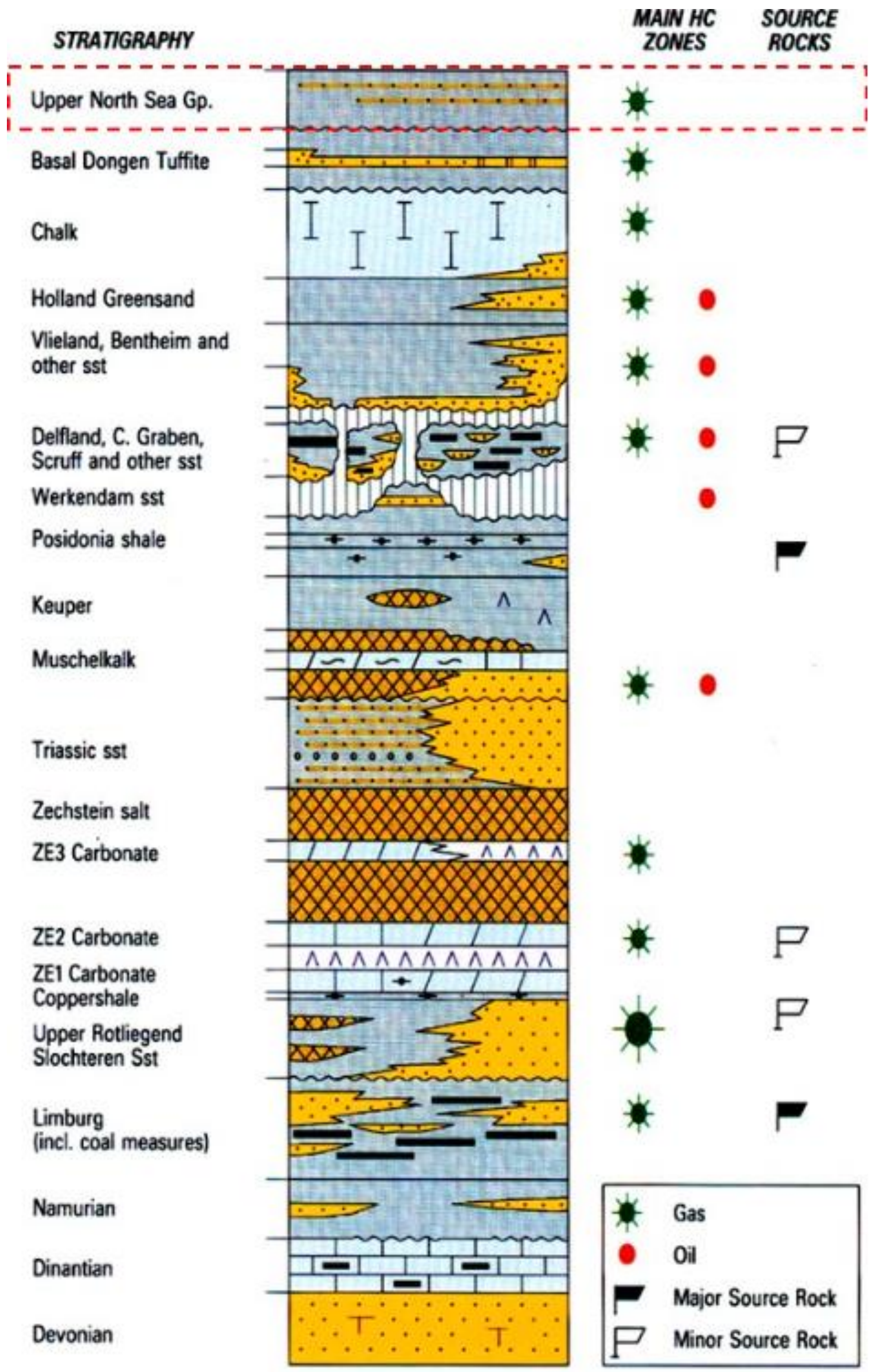


Figure 3. 2: *The hydrocarbon plays and stratigraphy of the North Sea Basin. The Upper North Sea Group is the area of interest for this study.*

3.2 Data Availability

a) Seismic Data

Seismic data over the F3 Block (Dutch sector) of the North Sea were acquired in 1987 and consist of 651 inclines and 951 crosslines. The size of the survey area is 24 km in inline direction and 16 km in crossline direction with a 25 m x 25 m bin size. The two-way travel time record length of the seismic data is 1,848 ms with a sampling rate of 4 ms. Due to unavailability of the seismic data at the northeast corner of the survey area, only the first 501 of the 651 inlines were used in this study.

b) Wells and available logs

The data from four vertical wells in the study area were available for this investigation F02-1, F06-1, F03-4, and F03-1. Wells F02-1, F03-1, and F03-4 were drilled in 1976 at X: 606549, Y: 6080124 and X: 623256, Y: 6082586 (UTM31), respectively. Well, F06-1 was drilled in 1981 at X: 607902, Y: 6077213. Sonic and gamma-ray (GR) logs were available for all the wells. Density data were available only for Well F02-1. The density and sonic logs of Well F02-1 were used to train a neural network relationship between density and sonic logs. The trained neural network was then used to compute sonic logs for the Wells F06-1 and F03-4. The probabilistic neural network (PNN) is a method of mathematical interpolation that makes use of architecture of the neural network, Probabilistic neural networks (PNN; Specht, 1990, 1991) are powerful transform approaches used to establish the mathematical relation between seismically derived attributes and porosity derived from an optimal training correlation (Chatterjee et al., 2016).

Density porosity for all the wells was computed using sandstone matrix porosity formula:

$$\rho_{density} = \frac{\rho_{matrix} - \rho_{log}}{\rho_{matrix} - \rho_{fluid}} \tag{3.1}$$

Where $\rho_{desnsity}$ is density porosity, ρ_{matrix} is matrix density (sandstone matrix, 2.65g/cm^3), ρ_{log} is measured bulk density, and ρ_{fluid} is mud-filtrate density (1.05 g/cm^3).

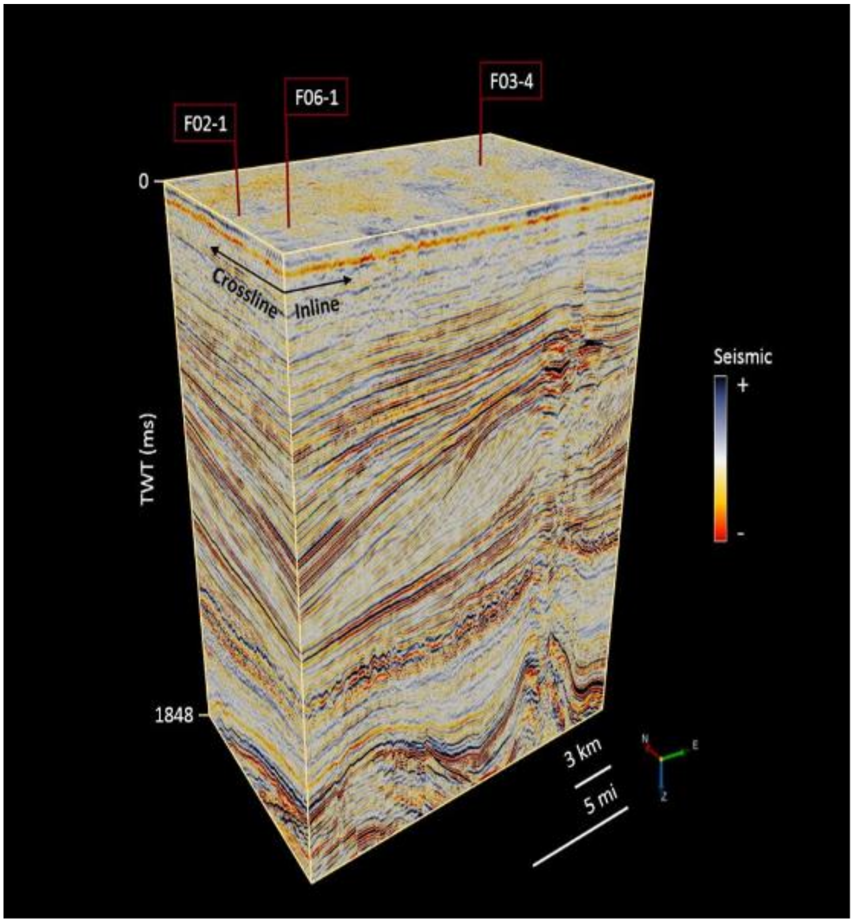


Figure 3. 3: *The 3D seismic volume with the locations of available wells.(petrel ,Kabaca, E,.2018)*

3.3 Methodology

In this study, is applied a three-step workflow to semi-automatically identify sequence boundaries. For identification of sequence boundary, seismic waveform, P-impedance, and porosity is used.

3.3.1. Seismic Attributes Computation

Seismic attribute analysis involves extracting or deriving a quantity from seismic data that can be analysed to enhance information that might be more subtle in a traditional seismic image, leading to a better geological or geophysical interpretation of the data

Seismic attributes are defined as any measurement extracted from seismic data (Taner et al., 1994). They provide some geological and geophysical information hidden in seismic images. The seismic attributes can measure time, amplitude, and attenuation of the seismic volume, we used original seismic waveform, P-impedance, and porosity as the inputs for semi-automatic horizon picking. These attributes were employed as they show sharp changes near sequence boundaries. (kabaca, E,.2018)

a) Acoustic Impedance Estimation

Acoustic impedance (Z) is a physical property , It describes how much resistance an ultrasound beam encounters as it passes through a tissue. Acoustic impedance depends on: the physical density of the tissue.The acoustic impedance inversion includes transformation of seismic traces to a reflection coefficient series and then into acoustic impedance (Lindseth, 1979; Lavergne and Willm, 1977). This technique is the reverse of conventional forward modelling since it integrates seismic and well log data to create a model of the earth (Russell B, Hampson D, Schuelke J, Quirein J, 1997). Latimer et al. (2000) pointed out the advantages of using impedance data versus conventional seismic data: "acoustic impedance is a rock property and a product of velocity and density". In contrast, "seismic reflection is an interface property and a relative measurement of changes in acoustic impedance between layers.

Having the data in layers, rather than at interfaces, improves visualization and vertical resolution. Also, the elimination of wavelet side-lobes and false stratigraphic-like effects makes sequence stratigraphic analysis easier."

The input of the seismic inversion process may be pre- or post-stack seismic reflection data. The basic theory behind all seismic inversion methods is found in the convolutional equation:

$$S = R^{*} \times W + N \tag{3.2}$$

Where S is the seismic trace, R is the Earth's reflectivity, W is the band limited wavelet, and N is the additive noise. Noise is assumed to be random and uncorrelated with the signal. The label * denotes the convolution. The reflectivity R is the contrast in acoustic impedance Z between the i^{th} and $(i+1)^{th}$.

$$R_i = \frac{Z_{i+1} - Z_i}{Z_{i+1} + Z_i} \tag{3.3}$$

$$Z_i = \rho_i \times v_i \tag{3.4}$$

Where v_i and ρ_i are the P-wave velocity and density of the i^{th} layer, respectively.

Post-stack seismic inversion is a processing technique that aims to extract the acoustic impedance of the subsurface from surface measurements (stacked seismic data) (Russell and

Hampson, 1991). The inputs of post-stack inversion usually include stacked seismic data, well log data, and a set of geological constraints in the form of a model. The way these inputs are combined depends on the inversion algorithms. (kabaca, E,.2018)

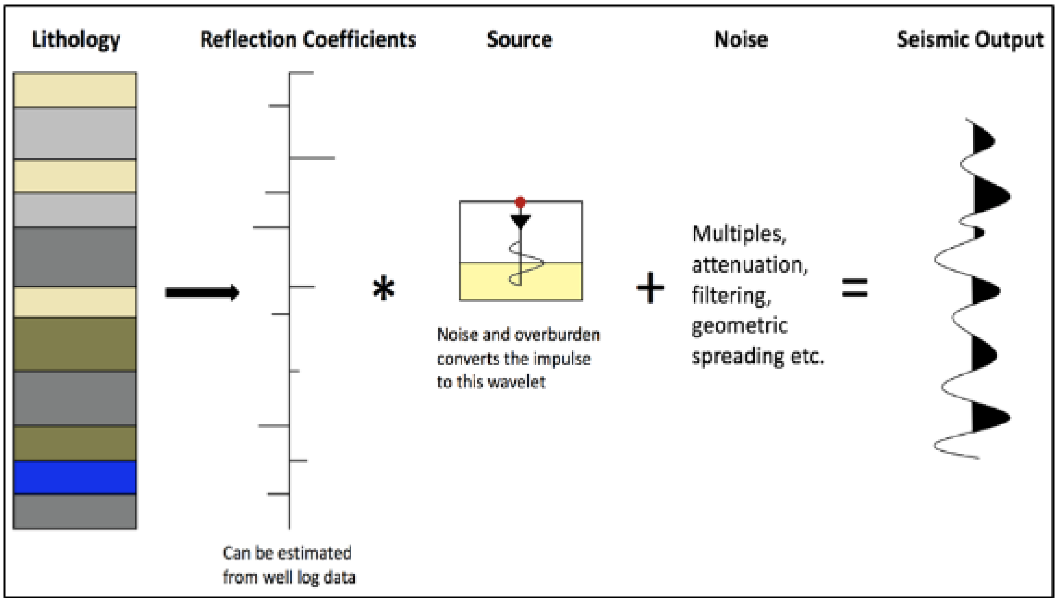


Figure 3. 4: *The convolutional theory. Reflection coefficient series are obtained from the impedance, which is the product of velocity and density. The seismic trace is the convolution between the Earth's reflectivity and a seismic source function (wavelet).modified by walden and walter, (kabaca, E,. 2018)*

Russell and Hampson (1991) described three post-stack seismic inversion methods: band-limited (BLI), sparse-spike (SSI), and model-based (MBI) inversion. Band-limited inversion tends to produce limited frequency results. Sparse-spike inversion produces lower resolution models compare to model-based inversion. Model-based inversion produces the most robust results. Therefore, a model-based inversion approach was used to estimate P-impedance volumes.

The first step in the model-based inversion is building an initial impedance model of the earth. The initial model is then perturbed until the derived synthetic seismic best fits the real seismic data. Some of the advantages of interpreting seismic data in acoustic impedance rather than seismic amplitude domain can be summarized as (Maurya and Sarkar, 2016):

1. Inversion increases the vertical resolution of seismic data by extending the frequency bandwidth. Increased resolution simplifies the stratigraphic definition.

2. Acoustic impedance is a product of sonic velocity and bulk density; therefore, impedance results can be directly compared to well log measurements.

The MBI uses a generalized linear inversion (GLI) algorithm that assumes the seismic trace and the wavelet are known and modifies the initial model until the input seismic trace matches the synthetic trace (Cooke and Schneider, 1983). GLI produces a model that best fits the measured data using a least squares method. Figure 3.3 illustrates the workflow of post-stack seismic inversion. Inputs include post-stack seismic data, well logs, and geological constraints (interpreted horizons and faults). The output is the estimated P-impedance.

Well log data and geological constraints are used to build the initial impedance model. GLI iterates updating the model parameters until the error between synthetic derived from P-impedance and seismic data is smaller than a user-defined threshold value. The mathematical expression of the GLI inversion can be expressed as (Russell, 1988):

$$F(M) = F(M_0) + \frac{\partial F(M_0)}{\partial M} \Delta M \tag{3.5}$$

Where F is modelling function, $F(M)$ is input seismic trace, M_0 is initial impedance model, $F(M_0)$ is synthetic seismic trace computed from the initial impedance model, M is true earth model, $\frac{\partial F(M_0)}{\partial M}$ is change in calculated values, ΔM is change in model parameters, and $\Delta F = F(M) - F(M_0)$ is error between the input seismic trace and the derived synthetic model trace. In this study, the CGG Veritas Hampson-Russell software (HRS) package was used to obtain the P-impedance volume.

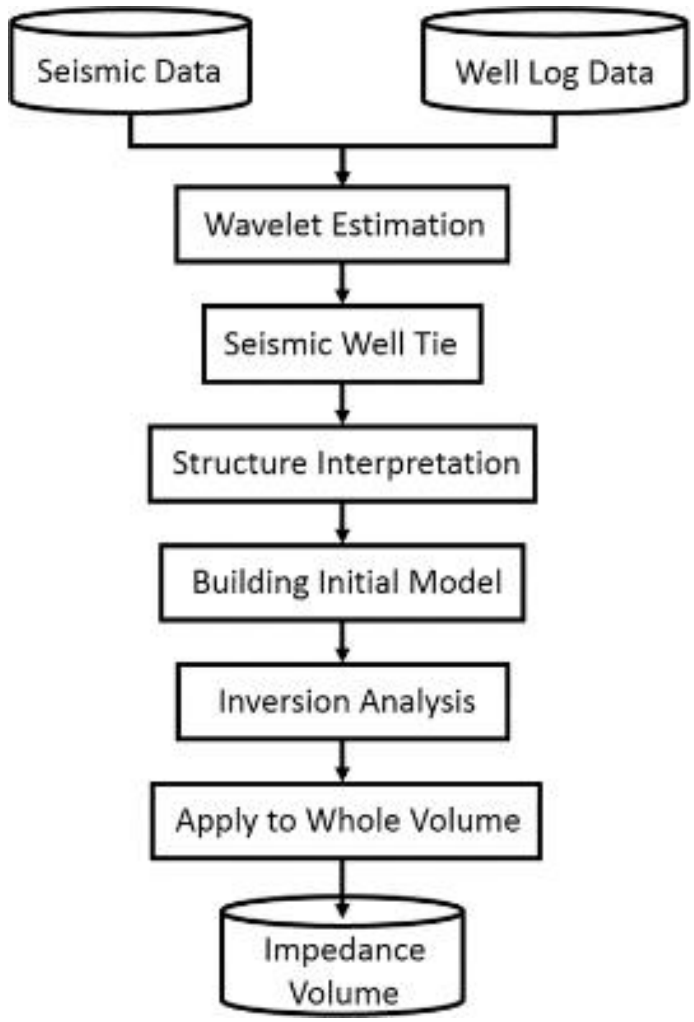


Figure 3. 5: *The workflow of model-based inversion (Kabaca,E,. 2018).*

3.3.2 Porosity Volume Estimation

Schultz et al. (1994) proposed the use of multiple seismic attributes to predict porosity. We employed the Emerge package of HRS to estimate porosity. The objective is to derive a non-linear (neural network analysis) operator that can predict porosity from a set of selected seismic attributes. Firstly, an appropriate seismic attribute group is selected by stepwise regression analysis. Then, a neural network model is trained, validated, and tested to obtain mathematical relations between porosity and seismic attributes at well locations. Finally, the trained model is applied to the whole seismic to create a 3D porosity estimation.

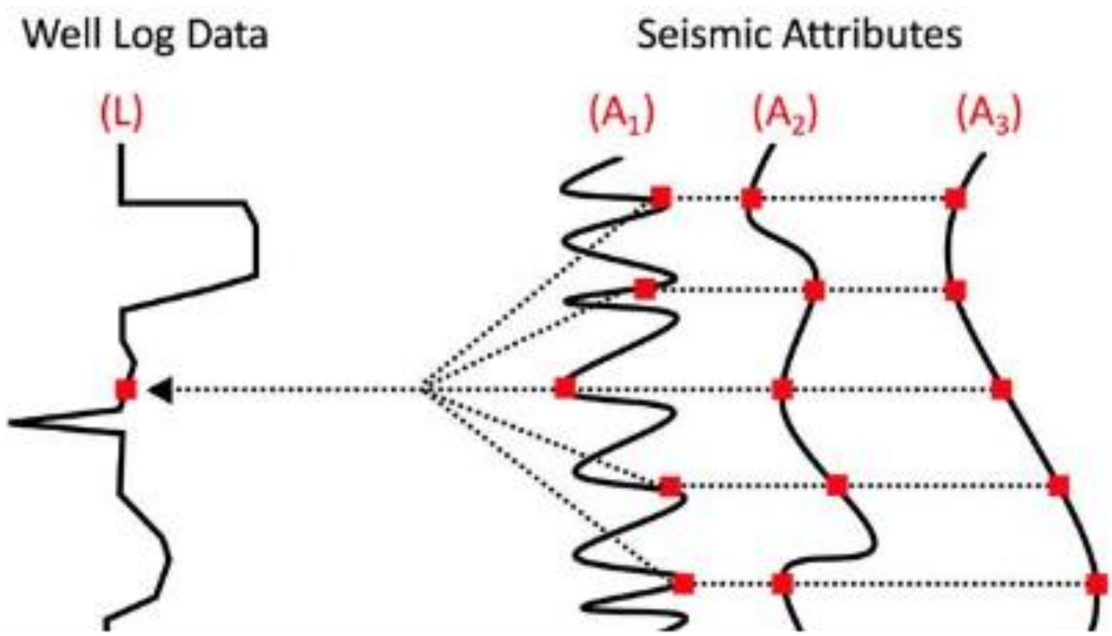


Figure 3. 1: *Prediction of the target well log data from a weighted group of seismic attributes. In the case of three attributes and five-point convolutional operator are used to estimate the value of one sample of porosity log (Modified from Hampson et al., 2001).*

Sometimes adding new attributes to the regression decreases fit ("overtraining" of Kalkomey, 1997). Emerge uses a cross-validation technique which divides the data into two sets: (1) a validation data set and (2) a training dataset (Draper and Smith, 1966). The training set is used to derive the weight coefficients through least-square optimization, and the validation set is used to value the fitting degree trough cross-plotting. The validation error curve gradually decreases and ends with the minimum, it is assumed that the number of attributes is optimum. In case of the validation error curve decreases and then starts to increase, the attributes are overtraining the system. The training dataset consist of training samples from all wells, unless specified.

CHAPTER IV

RESULTS AND DISCUSSION

4.1 Introduction

This section presents and discuss the results, presented in the order of its increasing complexity. Manual horizon interpretation is one of the most time-consuming tasks in seismic interpretation. The algorithm used in this study significantly reduced the horizon interpretation time without reducing the accuracy of interpreted horizons.

4.2 Wavelet Estimation and Seismic Well Tie

A seismic wavelet is the signature of the seismic source and the link between the seismic data (traces) and the geology (reflection coefficients) (Henry, 1997). Therefore, wavelet extraction is perhaps the most important step in the seismic well tie, which is the correlation of a synthetic seismogram calculated from well log data with the seismic data.

The seismic well is important because is used to know in which time and depth probably has the hidrocarbons.

The seismic wavelet is the link between seismic data (traces), interpretations and the geology (reflection coefficients). It must be accurately known and quantified in all stages of the seismic cycle (from modelling, acquisition, processing, interpretation, inversion and reservoir work).

A step in seismic processing to determine the shape of the wavelet, also known as the embedded wavelet, that would be produced by a wave train impinging upon an interface with a positive reflection coefficient.

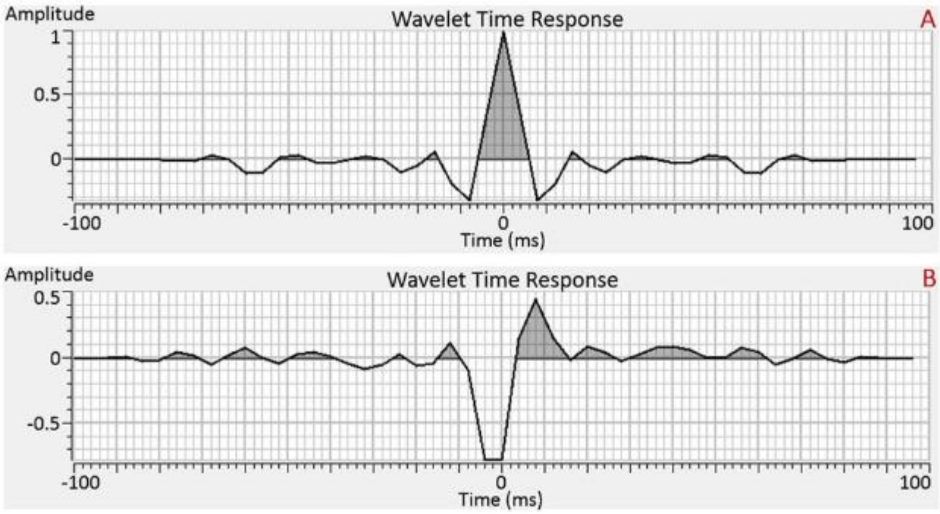


Figure 4. 1: *The seismic wavelet with (A) the statistical zero-phase Ricker wavelet, and (B) single average wavelet. The wavelets have a length of 200 ms.(kabaca, 2018)*

The synthetic seismogram is the convolution results between reflectivity derived from well logs and a wavelet. The purpose of seismic well tie is to integrate and calibrate information from well log data to the seismic section. To know exactly where is the hydrocarbons, The seismic well tie is the procedure of manually matching the synthetic and r seismic waveform.

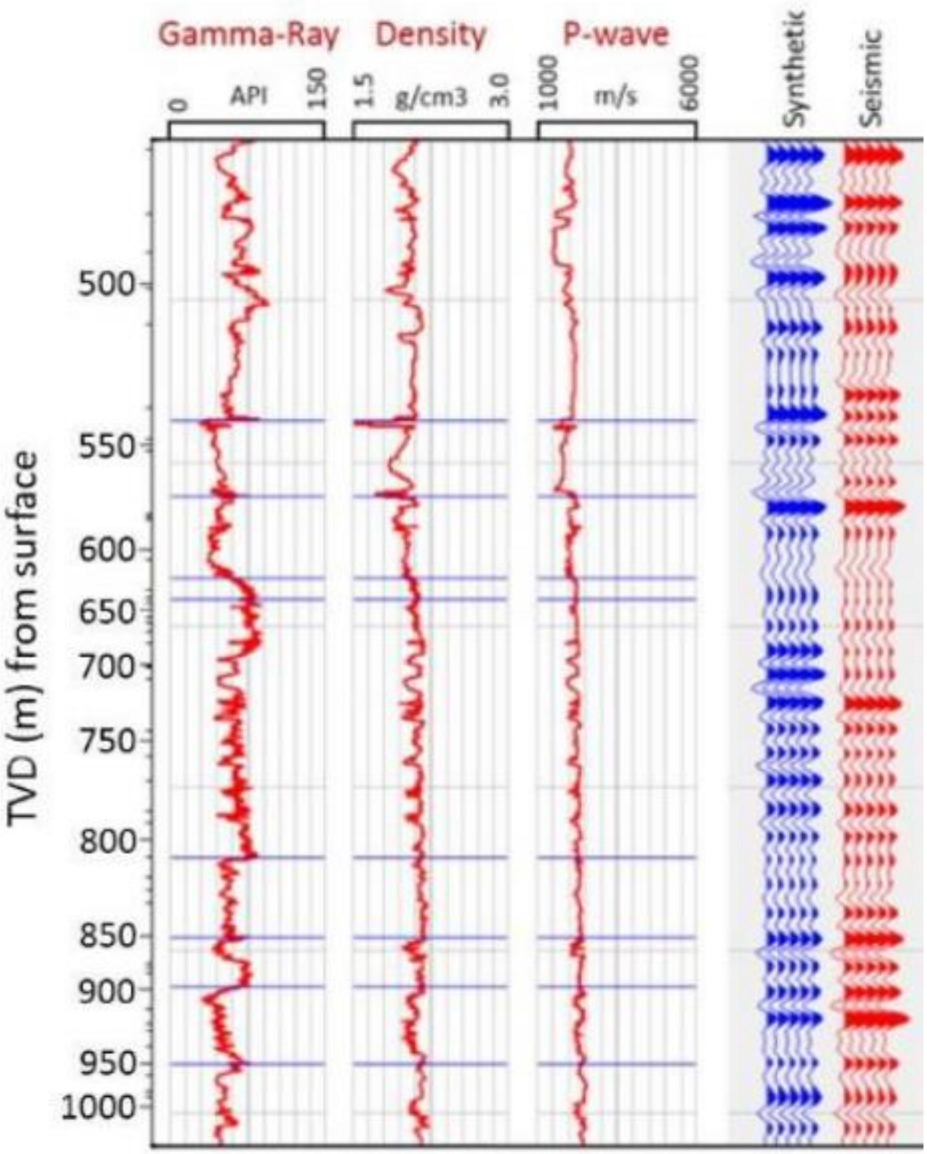


Figure 4. 2: *A seismic well tie using synthetic and seismic.*

4.3 Structure Interpretation

The model based inversion technique converts seismic data to a pseudo- acoustic impedance log at every trace. Acoustic impedance dataset is utilized in producing more accurate and detailed structural and stratigraphic interpretations than can be obtained from seismic (or seismic attribute) interpretation

The model-based inversion requires a basic model of geologic interpretation after seismic well tie. Structure interpretation consists of manual interpretation of seismic events (horizons) on individual seismic profiles in both inline and crossline directions throughout the survey area. The interpreted horizons and well logs are then used to build the initial background model needed for the model-based inversion (Maurya and Sarkar, 2016).

Acoustic impedance is a layer property of a rock and it is equal to the product of compressional velocity and density.The acoustic impedance of an instrument for any fingering is one of the major factors which determines the acoustic response of the instrument in that fingering. It determines which notes can be played with that fingering, how stable they are and it also helps determine whether they are in tune.seismic inversion is used to increase the resolution and reliability of the data and to improve estimation of rock properties including porosity and net pay. There are many different techniques used in seismic inversion.

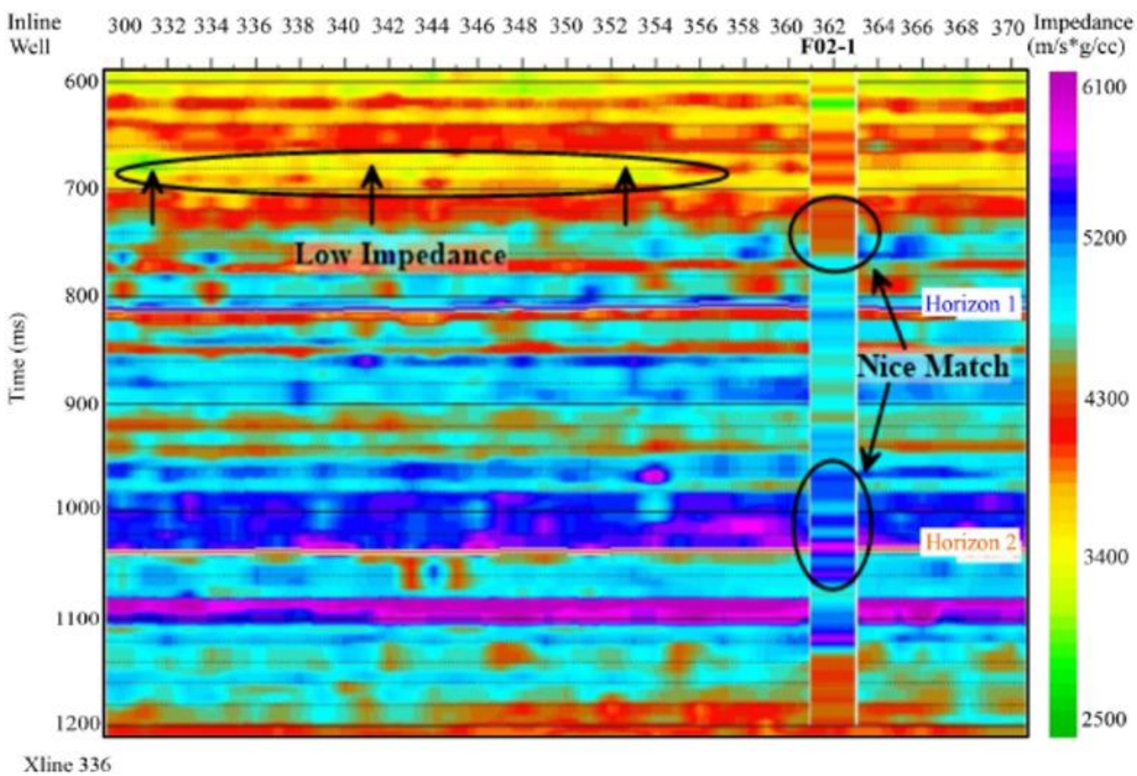


Figure 4.3: *A single crossline from the input 3-D volumes*

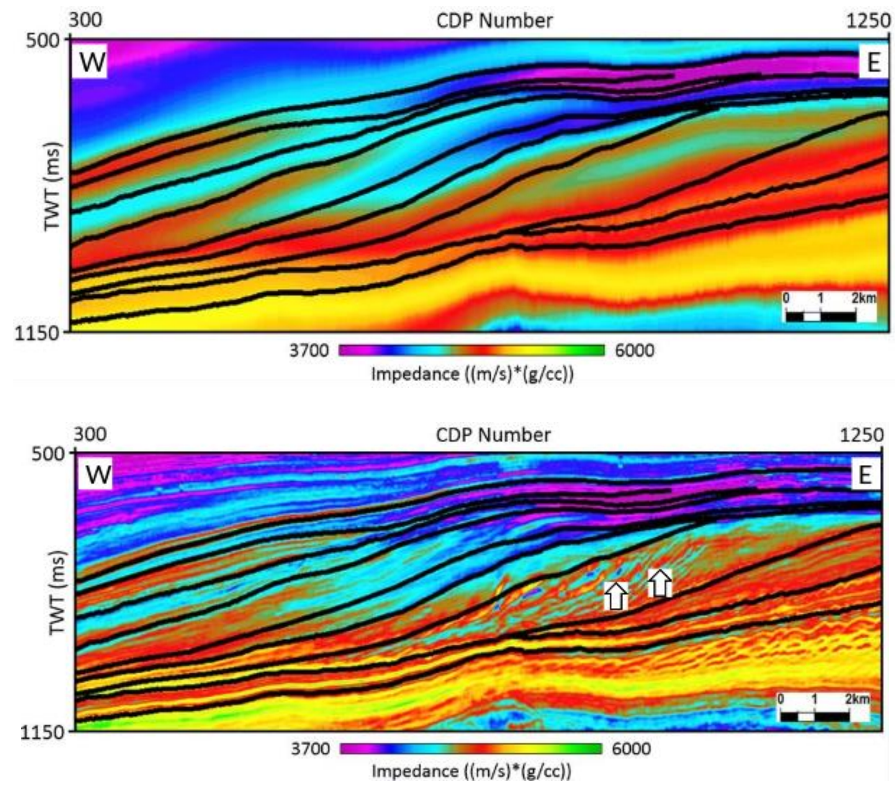
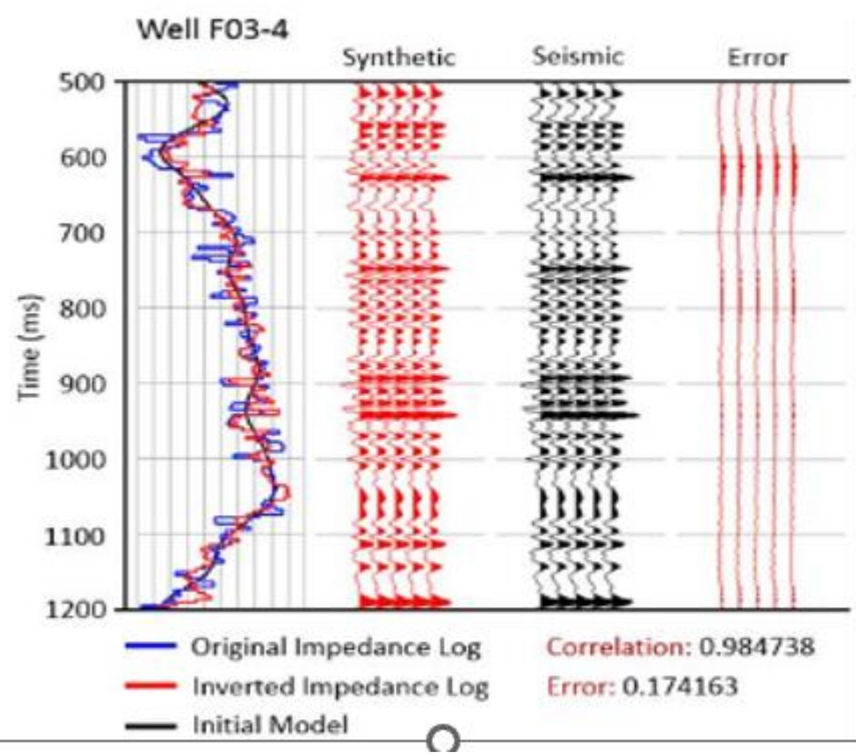


Figure 4. 4: *The initial impedance model used for the model-based inversion and The inverted P-impedance with interpreted horizons adapted by petrel , Kabaca E*



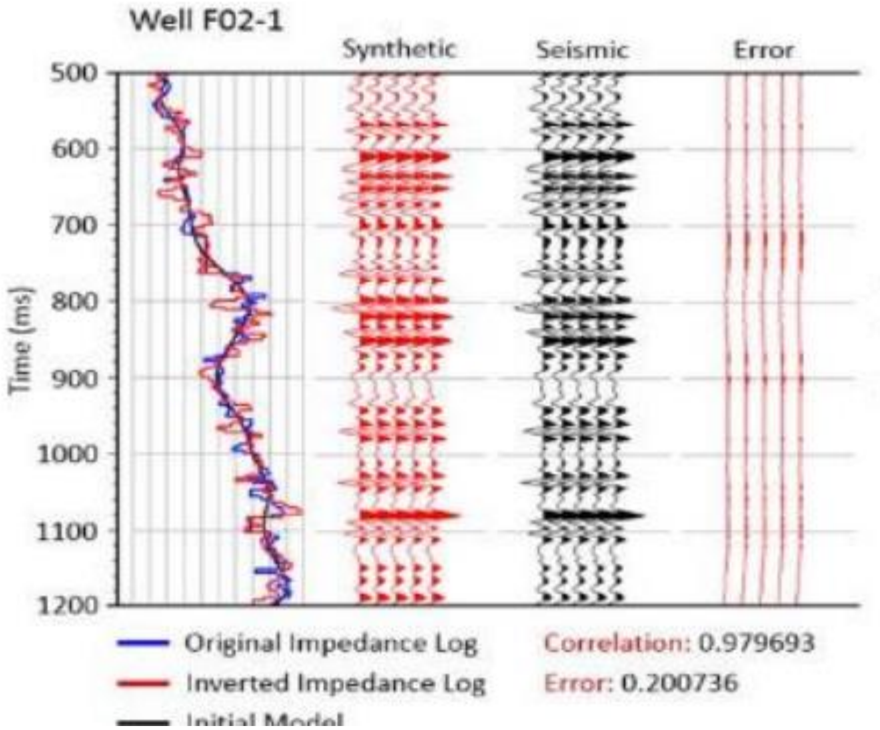


Figure 4. 5: *Inversion analysis results at well locations. adapted by petrel,*

Inversion analysis is performed by comparing the acoustic impedance log with the inverted acoustic impedance to set the inversion parameters at well locations.

4.4 Porosity

Porosity is a measure of the void spaces in a material and is a fraction of the volume of voids over the total volume. It is a phenomenon that occurs in materials.

The objective is to derive a non-linear (neural network analysis) operator that can predict porosity from a set of selected seismic attributes. Schultz et al. (1994) proposed the use of multiple seismic attributes to predict porosity.

A probabilistic neural network (PNN) is a feedforward neural network, which is widely used in classification and pattern recognition problems.

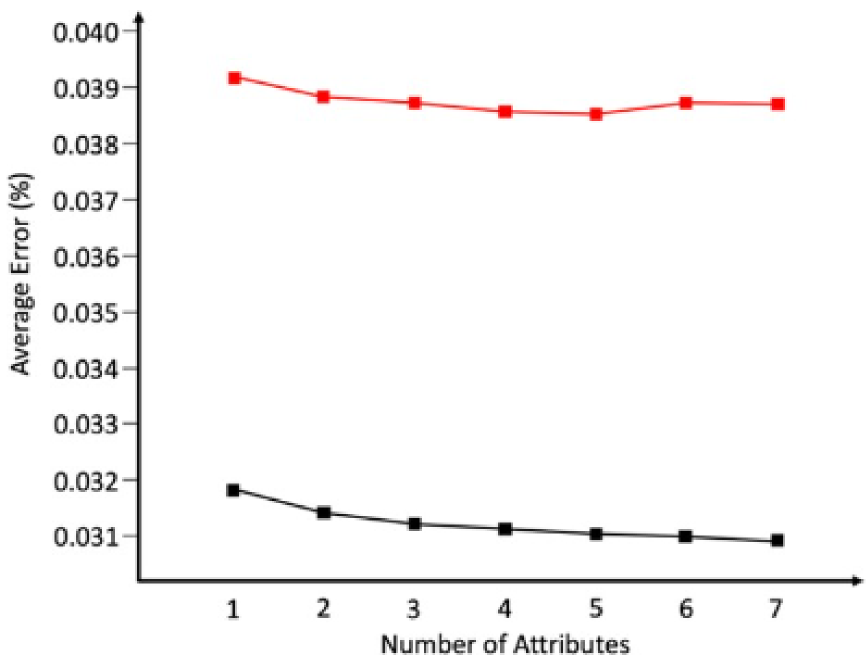


Figure 4. 6: *The results of the attributes training (black) and validation (red) procedure. The horizontal axis shows the number of attributes used in the prediction.*

Probabilistic Neural Network (PNN) The probabilistic neural network (PNN) is a method of mathematical interpolation that makes use of architecture of the neural network. The information used by PNN is a sequence of training data for every seismic sample in the examination windows for all the wells. The graph shows log values cross-plotted against a single seismic attribute. The red line shows the linear regression through least–square optimization. networks (PNN; Specht, 1990, 1991) are powerful transform approaches used to establish the mathematical relation between seismically derived attributes and porosity 53 derived from an optimal training correlation (Chatterjee et al., 2016). We employed Hampson-Russell software to perform PNN analysis and obtained a mathematical mapping relationship between the selected seismic attributes and porosity

Typically, the well log data have higher frequency content than the seismic attributes. Therefore, correlating the well log data with seismic attributes sample-by-sample may not be the optimal choice (Hampson et al., 2000).. The optimum operator length can be determined by using a testing tool provided in the Emerge software. The test suggests that a 1-point convolutional operator length has the minimum validation error of 0.031 in porosity when five attributes is used.

Table 4. 1: *List of attributes generated using single-attribute analysis for P-wave velocity.*

	Target	**Attribute**	**Error (m/s)**	**Correlation (fraction)**
1	Sqrt(P-wave)	(inverted_main_Zp)**2	128.469345	0.859274
2	Log(P-wave)	(inverted_main_Zp)**2	128.590775	0.855414
3	P-wave	(inverted_main_Zp)**2	130.768112	0.857451
4	1/(P-wave)	inverted_main_Zp	132.664215	– 0.831746
5	Log(P-wave)	inverted_main_Zp)	139.001083	0.834213
6	(P-wave) **2	(inverted_main_Zp)**2	142.085083	0.834825
7	1/(P-wave)	Sqrt(inverted_main_Zp)	142.686768	– 0.819614
8	Sqrt(P-wave)	Inverted Zp	142.717499	0.827788
9	P-wave	Inverted Zp	147.126892	0.815373
10	Log(P-wave)	Sqrt(Inverted Zp)	149.441696	0.813780
11	Sqrt(P-wave)	Sqrt(Inverted Zp)	152.914734	0.803001
12	1/(P-wave)	Log(Inverted Zp)	154.870148	– 0.802565
13	P-wave	Sqrt(Inverted Zp)	157.036591	0.786233
14	Log(P-wave)	Log(Inverted Zp)	160.289566	0.789352
15	1/(P-wave)	(Inverted Zp)**2	160.564713	– 0.834188

Table 4. 2: *List of attributes generated using multi-attribute regression for P-wave velocity.*

	Final attribute	Training error (m/s)	Validation error (m/s)	Validation error (m/s)
1	Sqrt(P-wave)	(Inverted Zp)**2	120.779972	137.834616
2	Sqrt(P-wave)	Amplitude weighted phase	115.095175	134.815238
3	Sqrt(P-wave)	Average frequency	111.342122	141.358826
4	Sqrt(P-wave)	Apparent polarity	108.567997	141.454136
5	Sqrt(P-wave)	Integrated absolute amplitude	106.380417	140.759496
6	Sqrt(P-wave)	X-coordinate	104.720408	140.784787
7	Sqrt(P-wave)	Instantaneous frequency	103.119352	139.656875
8	Sqrt(P-wave)	Quadrature trace	101.830385	141.567930

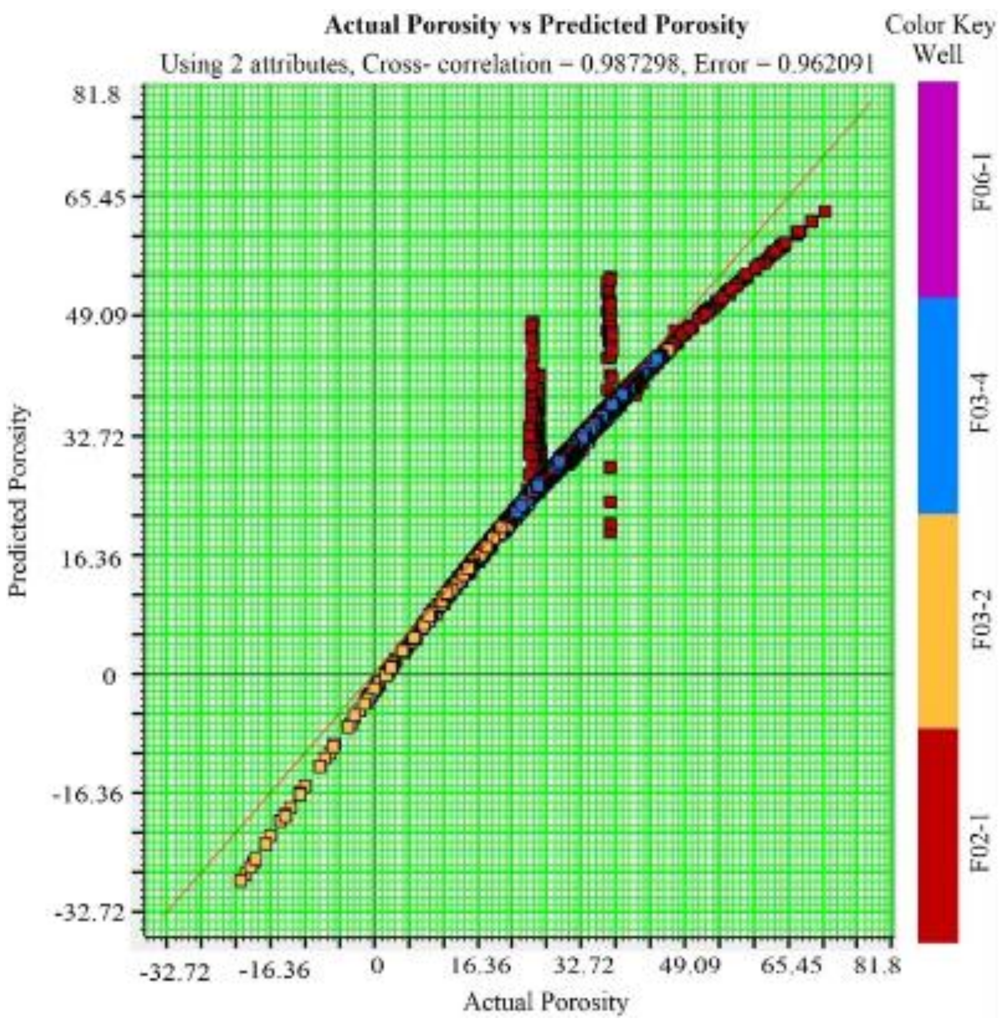


Figure 4.7: *Crossplot between original porosity and predicted porosity of all four wells Petrel*

ii. Probabilistic Neural Network (PNN)

The probabilistic neural network (PNN) is a method of mathematical interpolation that makes use of architecture of the neural network. The information used by PNN is a sequence of training data for every seismic sample in the examination windows for all the wells

Probabilistic neural networks (PNN; Specht, 1990, 1991) are powerful transform approaches used to establish the mathematical relation between seismically derived attributes and porosity derived from an optimal training correlation (Chatterjee et al., 2016). We employed Hampson-Russell software to perform PNN analysis and obtained a mathematical mapping relationship between the selected seismic attributes and porosity.

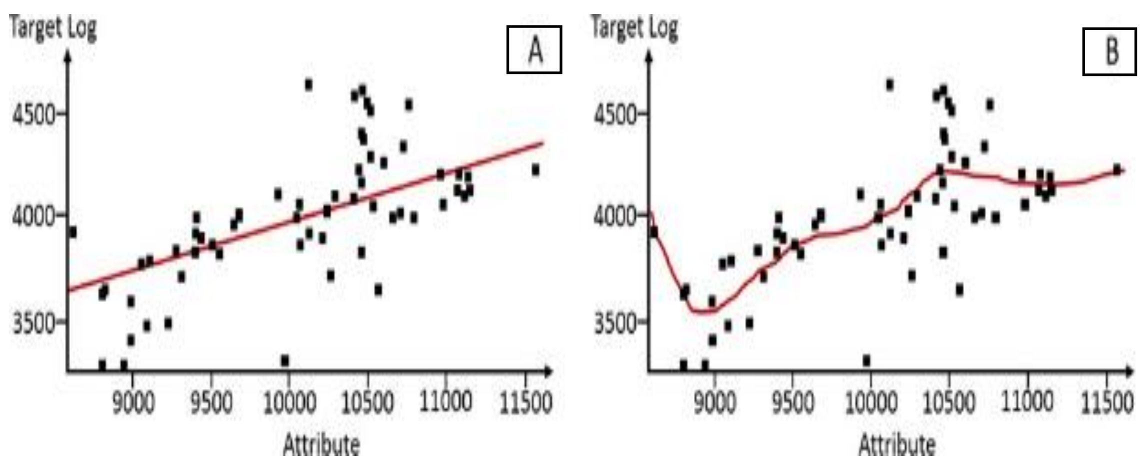


Figure 4.8: *Cross plot of target log against seismic attribute using (A) the linear relationship regression, and (B) relationship obtained using PNN (Modified from Hampson et al., 2001).*

After performing the PNN, , the final correlation between predicted porosity and original well porosity is 0.80, with an error of 0.035%..

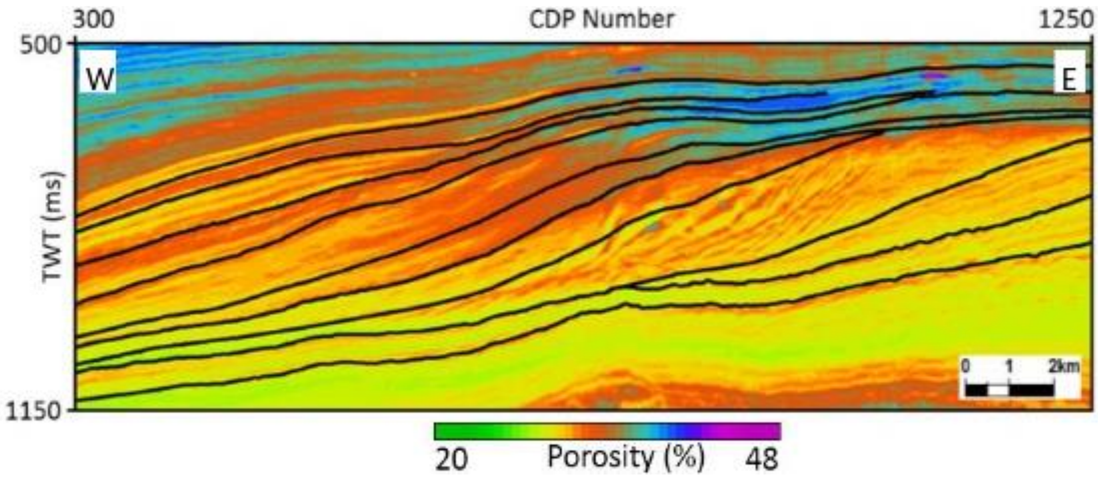


Figure 4.9: *A representative estimated porosity inline section.*

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Introduction

This chapter presents the study conclusions and the recommendations. The attributes used in this study are the P-impedance, porosity, and seismic waveform.

5.2 Conclusions

In the present study, a variety of petrophysical parameters, i.e., impedance, porosity, velocity, are estimated and seismic attributes, the envelope amplitude, RMS amplitude, instantaneous phase cosine and instantaneous frequency. Regarding the analysis Further, the inversion of entire seismic section for impedance shows a relatively low impedance varying from 2000 to 7000 m/s*g/cc in the region which indicates the presence of loose formation in the area. The analysis suggests a low-P-impedance zone at 680 ms time which may be due to the presence of a hydrocarbon reservoir, which shows a correlation coefficient of 0.80 and 0.91 for P-wave velocity and porosity, respectively, and show area that has P-wave velocity varying from 1000 to 2500 m/s and the porosity varying from 20 to 42%.

The results demonstrate a good match with the measured seismic data and well information. The methods are consistent with the well log. The application proved that the attributes combination used in this study does not necessarily have to fit any data in every case. Based on the studies presented here, and for a more advanced study, the use of attributes as a coherence cube, as it allows better results in the structural analysis, as is the case of failures, as they allow us to identify small-sized failures. Attribute is the spectral decomposition, as it allows analysing the frequency content in the seismic in greater detail, crafting a window of this seismic attribute provides a means to investigate seismic characteristics that truly refine a given frequency, at the expense of the Instantaneous frequency.

5.3 Recommendations

To qualify the seismic data for estimation of seismic attributes and to determine the well logs properties and to stablish the correlation within seismic attributes. We recommend for further studies, use of 3D Reservoir simulation with use of updated/recent version of Petrel software and integrate more data, since in this study only we used four well logs available and seismic data.

To create laws that encourage companies in the oil and gas sector in Mozambique to submit quarterly and annual reports not only to the National Institute of Petroleum, but also to make them available in academies, relevant websites linked to the aforementioned industry, and newspapers with the highest circulation in the country.

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