A Novel Analytical Technique for Evaluating Fractured and Non-Fractured Reservoirs

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By

Zohreh Movahed

Cambridge
Scholars
Publishing

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This book first published 2024

Cambridge Scholars Publishing

Lady Stephenson Library, Newcastle upon Tyne, NE6 2PA, UK

British Library Cataloguing in Publication Data
A catalogue record for this book is available from the British Library

ISBN: 978-1-0364-0999-9
ISBN (Ebook): 978-1-0364-1000-1

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CHAPTER 1

INTRODUCTION

1.1 Introduction

Studying the outcrops of the target formations/reservoirs is of great importance for understanding the possible geological (structural and sedimentological) characteristics of a reservoir. These features are studied at different scales to determine their lateral and vertical extent and distribution. Various technologies, such as Brunton compasses/inclinometers, topographic maps, aerial photographs, and satellite images mainly achieve this. A similar approach is needed for delineating and characterizing the reservoirs in the subsurface. The large-scale subsurface features are delineated with the surface seismic (2D and 3D) techniques. However, these techniques' coarse resolution (generally greater than 10 m) does not allow for feature identification of smaller scales (for instance, cross-bedding, bedding, fractures, and vugs/moulds) that are very useful for the detailed characterization of reservoir rocks.

Borehole images are very useful in cases where information on geological (structural and sedimentological) and reservoir features is required. Structural dip, by definition, is the present-day formation dip used to build the structural cross-section. It is also a record of the post-depositional structural alteration and may indicate the tectonic history of the sequence. It is not an average dip for all the bedding planes. Apart from structural analysis, the investigation of fractures is the main application for image logs in Dezful Embayment, Iran. Information on fractures is important because of their higher permeability, hence their biggest influence on reservoir producibility. Schlumberger provides high-quality borehole images in wells drilled with all types of mud: water-based and oil-based. These images can be acquired in wells of all geometries ranging in deviation from 0.0 degrees to more than 90 degrees. It is now possible to get resistivity of the invaded zone (Rxo) in the wells drilled with oil-base mud using the state-of-the-art imaging tool called the Oil Base Mud Imager (OBMI) (Schlumberger 2005). By using advanced interpretation, it can compute permeability from the borehole images in carbonates.

This study highlights the importance of data integration and borehole images in the domains of geology, petrophysics, geomechanics/drilling, reservoir and production engineering in different oil fields. Borehole images logged in the Asmari and Sarvak reservoirs from oilfields like Lali, Gachsaran, Marun, Mansuri and Pazanan are discussed (Figure 1.1).

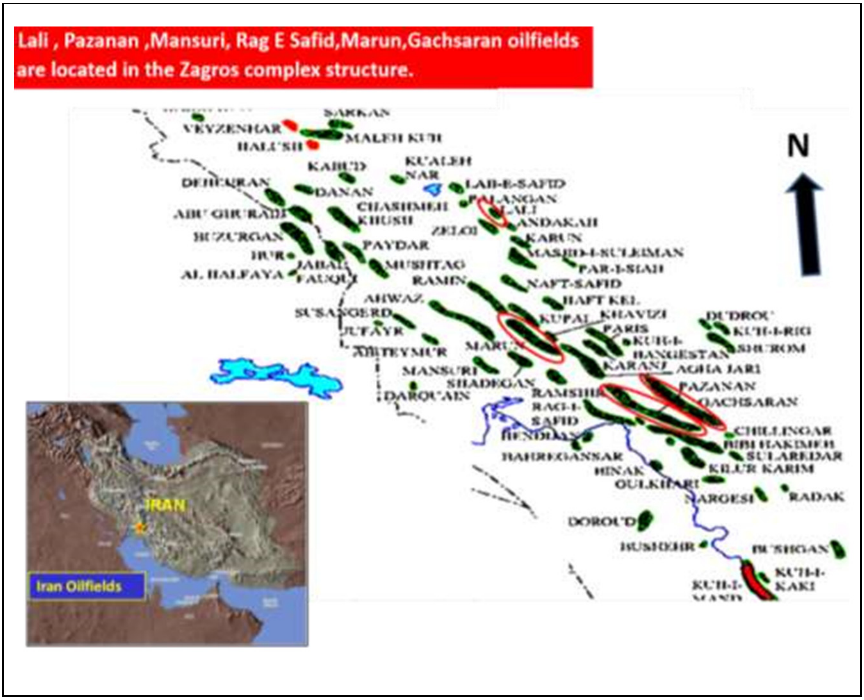

Figure 1.1 Studied oilfields (red colored) in Dezful embayment.

The Asmari formation consists of limestones: dolomitic, argillaceous, and anhydrite. The lithology of the Sarvak Formation is limestone, and it lies below the Ilam reservoir (Motiei 1993) (Figure 1.2). Our research establishes a technique to increase understanding of the Asmari and Sarvak reservoirs by using a new application of image logs.

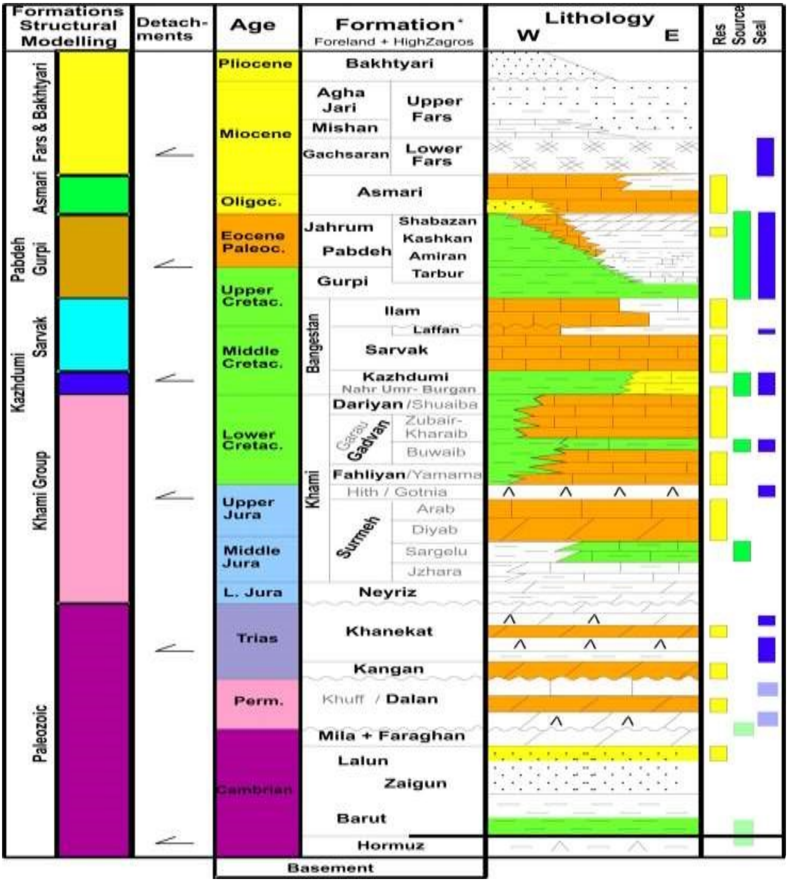

Figure 1.2 Asmari and Sarvak reservoirs in Iran (Bosold et al., 2005).

1.2 Problem Statement

Crossing the Asmari reservoir is not easy in some cases due to structural complexities, such as when there is a thick pile of evaporates from the Gachsaran Formation over the reservoir. In some wells, thicker formations than expected are found. Dip classification based on a geological log has the advantage of providing a direct representation of the structural origin and identifying Asmari fault and fracture systems, their influence on production and resolving structural complexity.

Fracture intensity and deep-rooted fractures increase the risk of unexpected water production, so it is vital to know whether the reservoir is fractured or not. If it is fractured, then what is the kind of fracture (open or closed), and what is the intensity? Do they occur as a single set or multiple sets, and what orientation is their dominant strike? Solutions to questions like these support geologists and reservoir engineers in increasing oil production (Movahed et al. 2014), and in this study, the borehole imaging tools, like the Formation Micro Imager (FMI), Oil Base Mud Imager-Ultrasonic Borehole Imager (OBMI-UBI) are interpreted to find solutions for fracture systems and fracture attributes.

A permeability analysis of dual porosity systems with heterogeneous distribution of dissolution fabrics can be evaluated by using the FMI. However, an oil company will not use permeability from FMI in a case when there are no formation testing data in the well for fracture and reservoir modeling. In this study, image logs provided the most representative measurements in geological and petrophysical heterogeneous formations and presented a method to measure permeability from FMI in the Asmari and Sarvak reservoirs.

OBMI-Rxo is a high-resolution curve that is sensitive to fluid mobility near the borehole wall and indicates invasion and indirect lithology. However, oil companies are not currently using an accurate Rxo curve of OBMI for reservoir and petrophysical applications. This method, using resistivity classes, is used to show how the high resolution OBMI curves can be used. The result of this research demonstrates the new analytical method to evaluate fractured carbonate and clastic reservoirs in Iran.

Most of the wells drilled in Iran suffer from geomechanical hazards owing to the high in situ stress related to the proximity of the Zagros mountains, and it is not always possible to acquire wireline log data because of the borehole condition (Movahed et al. 2014). In this study, advanced borehole shape analysis by using FMI and UBI helped regarding borehole instability and improved information about the well condition.

1.3 Objectives of the Research

The objectives of the research are given below:

1. To develop an accurate structural model for the Asmari reservoir.
2. To characterize fractures in the borehole.

3. To compute reliable index mobility from OBMI and index permeability from FMI.
4. To evaluate the borehole condition in order to reduce drilling risk and avoid potential well bore damages.

1.4 Scope of the Research

Borehole images were integrated with other data (petrophysical, reservoir, and geophysical) to understand the various characteristics of the Asmari, both in oil-based and water-based mud systems. In this study, borehole images are used to solve different issues in geology, petrophysics, reservoir engineering, production engineering, sedimentology, geomechanics and drilling in oil fields, which are explained as follows:

1. Image log data are processed for a number of factors that may affect the quality of the images in Geoframe. Such factors include variations in the speed of the tool relative to the drill-pipes, or cable speed, and sticking of the tool. Additionally, image logs are equalized and normalized to improve the information about features in them. Interpretation typically starts with hand-picking dips using sinusoid techniques on an image log presented at 1:20 or 1:10 scale so that the geological features are easily visualized. Once dips have been picked, they have to be classified into bed boundaries and fractures.
2. Interpreting structural dip resolved structural complexity, thus providing the exact location of the well in the Asmari reservoir, which could not reach the lower contact of Asmari after interpreting the FMI images and petrophysical logs in wells LL-26.
3. The structural dip from PZ-126 was used as input for permeability analysis, and it was imported into the Bortex module and computed reservoir heterogeneity from FMI was used to extract heterogeneities and layer details from the images. In addition to formation heterogeneities, the software also calculated the index permeability of the reservoir. Fracture properties (open or closed), occurrence, orientation, spacing, and porosity were interpreted by using an image log and imported as indirect input for permeability analysis.
4. The OBMI structural dip data is imported into the Bortex software in the MN-322. The OBMI tool was used to identify zones of higher permeability when combined with conventional induction logs and porosity logs. Separation between the Rxo curves (one from each of

four OBMI pads) and induction logs due to invasion of oil in the mud indicated higher permeability.

5. The borehole cross sections are interpreted to give a very detailed account of the in situ stress conditions by using UBI.

CHAPTER 2

LITERATURE REVIEW

2.1 Introduction

Owing to low-quality 3D seismic data and limited well control, geoscientists' opinions differed as to how to interpret the structural configuration of faults and reservoirs properly. As a result, existing seismic interpretations have substantial uncertainties. Key questions include: Where exactly is the main thrust fault, and what is its strike and dip? Where are the secondary faults? To obtain reliable structural dips and improve its understanding of this highly complicated structure (Dauod 2010), FMI data were collected and interpreted in this challenging, complex reservoir.

In addition to structural complications, fracture characterization is quite important for permeability analysis of the Asmari fractured carbonate reservoir. The fractures play a key role in the production of tight carbonate reservoirs. Significant heterogeneity in these reservoirs is found in all dimensions, and predicting reservoir continuity is challenging. Because of the large vertical resolution contrast between cores (actual scale) and conventional logs (averaged responses over a few meters), the extrapolation of small-scale heterogeneity into uncured wells using a traditional approach is unreliable. High-resolution log data, like dip meters and image logs, are required to characterize small-scale heterogeneity, which is essential to a good three-dimensional (3D) geological model that predicts true reservoir behavior. Our research demonstrates a method to increase the reservoir description of the Asmari and Sarvak reservoirs by using an advanced application of image logs.

2.2 Asmari Reservoir

The Asmari Formation (one of the best-known carbonate reservoirs in the world) was deposited in the Oligocene-Miocene shallow marine environment of the Zagros foreland basin (Alavi 2004), and it is best developed in the Dezful embayment zone (Sepehr 2004). The Asmari Formation overlies the Pabdeh and its time equivalents, the Shahbazan and Jahrum formations. The

Asmari was the first reservoir to produce commercial quantities of oil in Iran. The production capacity of the Asmari Formation is extremely high and provides the bulk of oil production from southwest Iran. The Asmari Formation consists of 314 m of limestone: dolomitic, argillaceous, and anhydrite (Motiei 1993). To the south of the Dezful embayment, its lithology changes into a mixed siliciclastic-carbonate deposit consisting of carbonate beds with several intervals of sandstone, sandy limestone and shale. This facies provides the Ahwaz Sandstone Member in some oil fields such as Ahwaz, Marian and Mansuri (Motie, 1993). Marun sandstone is a shoreface deposit. Distribution along the strike of the Zagros foreland basin is restricted to the southwestern margin as a number of elongate northwest-southeast siliciclastic bars (Alavi 2004) (Figure 2.1).

2.3 The Sarvak Reservoir

The Sarvak Formation reservoirs of the Bangestan Group lie under many of Khuzestan's Asmari reservoirs. The porosity of this shelf wackestone is variable. Lower porosities occur on the slope and basin carbonates. However, the shelf's higher-energy facies can have porosities up to 20% and permeability of several hundred mD. Most of Iran's Cretaceous reservoir is fractured, but these frequently exhibit a good primary porosity in the packstone and grainstone at the top of regressive cycles. Because of the Sarvak formation's great thickness (>800m) and the large amplitude anticlinal folding, tremendous volumes of hydrocarbons have been trapped in the Sarvak and associated Ilam reservoirs. Unfortunately, the fracture systems in these carbonate sequences are not as well connected as those of the Asmari. The reservoirs are, therefore, multi-layered and less prolific (Sorkhabi 2014) (Figure 2.1).

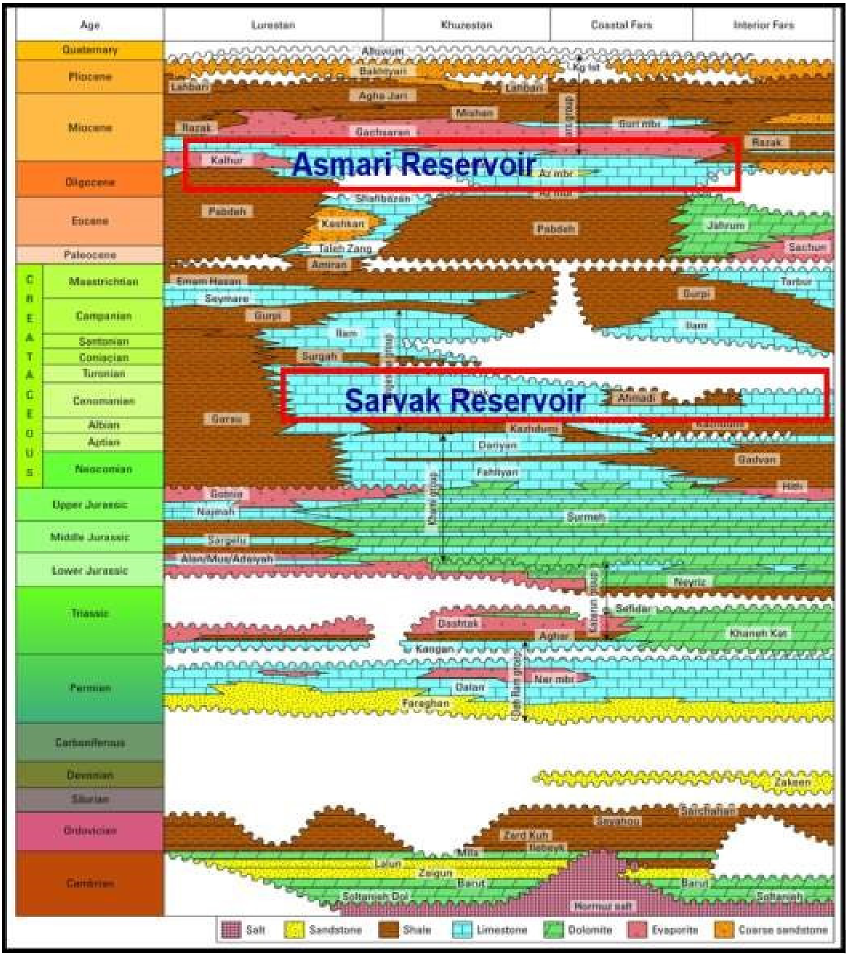

Figure 2.1 Asmari and Sarvak reservoirs in Iran (Schlumberger 2005).

2.4 Structural Complexity in the Zagros and Studied Oil Fields

The structure in the southern basin oil fields of Iran is quite complex due to compression along the northern edge of the Arabian plate marked by the Zagros Mountain belt, which is 200–300 km wide (Figure 2.2 to 2.3). It is 1200–1400 km long and crosses most of Iran (Stocklin 1968; Szabo and Kheradpir 1978; Tatar et al. 2004). It was caused by the Arabian plate colliding with the continental blocks of Central Iran during the Zagros orogeny, which began in Miocene times and continues today (Stocklin 1968). It was the strongest tectonic event in southwest Iran.

Starting in the late Miocene, this mountain-building episode is still active, as evidenced by the tilting observed in some very young conglomerate deposits. The area immediately southwest of the crush zone is intensely folded and faulted, and sediments exposed here are generally of Mesozoic age (Figure 2.4). The intensity of folding gradually decreases towards the Persian Gulf, where younger rocks are seen in the outcrops. The Zagros Mountains' folded belts are characterized by a concentrically folded belt (Mitra 2002). Broad anticlines and pinched and narrow synclines characterize the Cretaceous and younger units.

Therefore, out-of-syncline thrusts should be common within these pinched synclines, particularly in the more competent units. In addition to crustal shortening and thickening along the thrust faults, strike-slip faulting also complicated the structural style of the region. It is understood that, most probably, the convergence between the two plates was partly accommodated by the rotation and lateral movement of the crust along these faults.

Thus, accurate structural data are required to plan exploration and development wells due to the complex nature of the structures (like Gachsaran, Pazanan, Lali, etc.) comprising the Zagros Mountain belt (Figure 2.2). In some wells, a higher-than-expected thickness of formations is found. In some cases, it is caused by steeper bedding dips and in some, it is due to reverse faults. In some cases, it is not so easy to determine the exact cause of the unexpectedly higher thickness (Movahed et al. 2014). To find a solution, the borehole image log has a very important role in identifying structural and reservoir geometry (Soliman et al. 2010) and proper reservoir characterization by using them in thinly laminated reservoirs is a key to successful field development (Daungkaew et al. 2012).

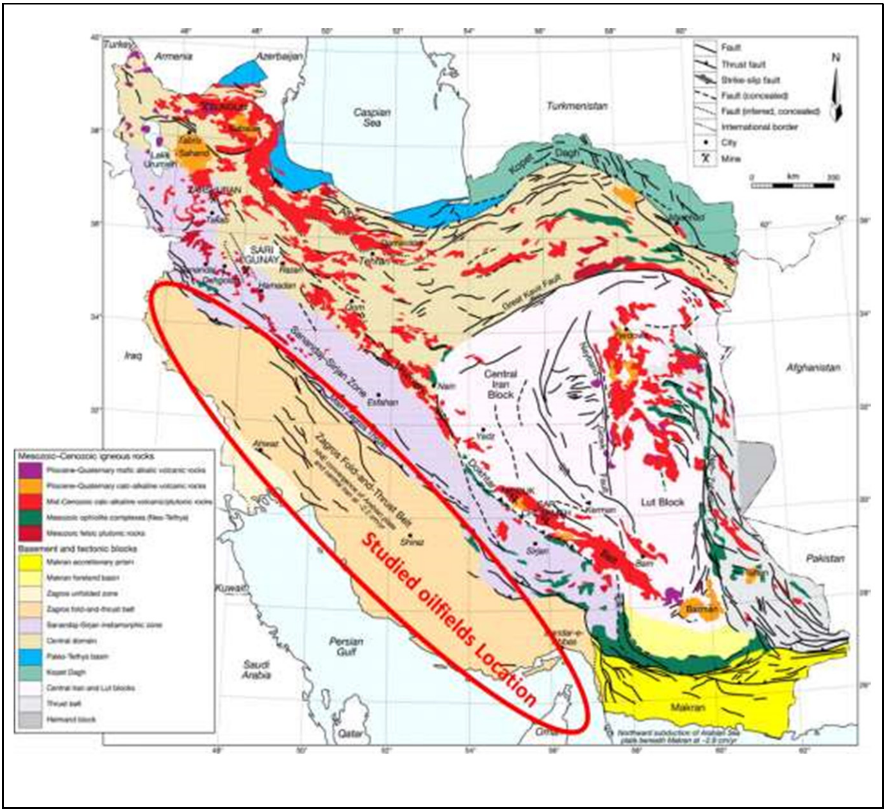

Figure 2.2 Geological and structural units of Iran (Richards et al. 2006).

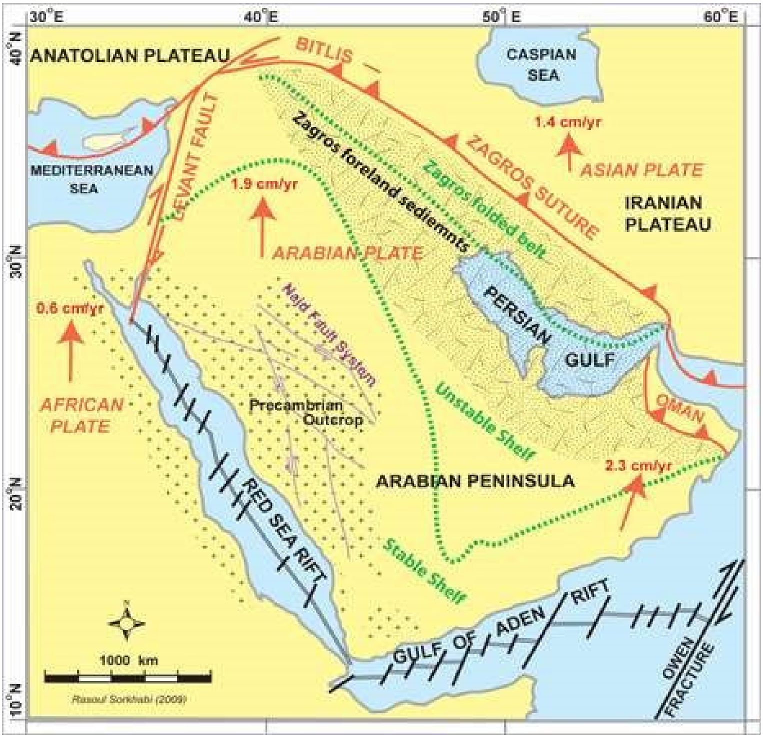

Figure 2.3 Tectonics map showing the location of Iran between the Eurasian and Arabian tectonic. Foreland folding in the southwest of Zagros convergence and large-scale strike-slip faults are indicated in Iran (Motiei 1995).

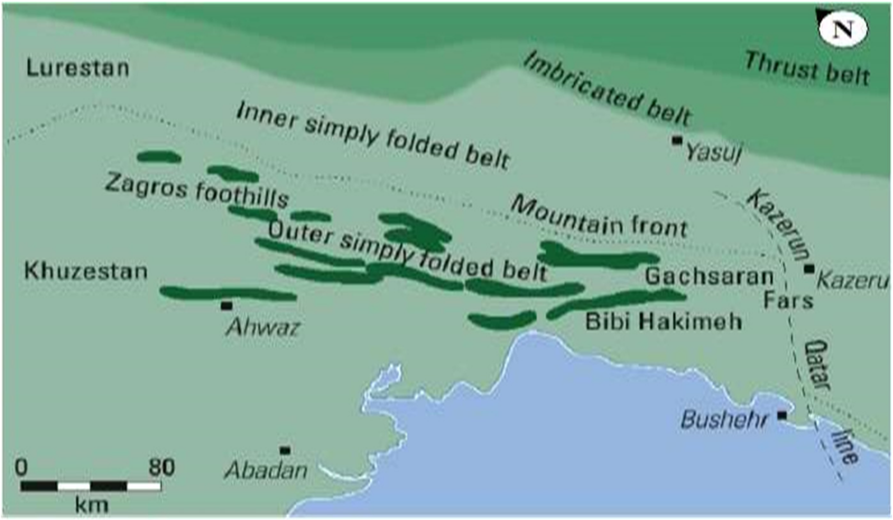

Figure 2.4 NW-SE trending major anticline structures in the Foreland basin of the Zagros Mountains (Motiei 1995).

2.4.1 Fault Types in Complex Reservoirs

Rocks respond to stress (being squeezed or pulled apart) near the Earth's surface by breaking. When rocks break, and there is no balance along either side of the break, the break is called a fracture or joint. Rocks can also break as a result of thermal extension and retrenchment, the effects of fluids freezing, or when rocks are pressed together or pulled apart. When the rocks move past each other along the fracture surface, it is called a faulting. Fault surfaces are often nearly planar, and that planar surface is referred to as a "fault plane". There are four types of faulting: normal, reverse, strike-slip, and oblique (Figure 2.5).

A normal fault is one in which the rocks above the fault plane, or hanging wall, move down relative to the rocks below the fault plane or footwall. A reverse fault is one in which the hanging wall moves up relative to the footwall. When rocks on either side of a nearly vertical fault plane move horizontally, the movement is called strike-slip. An oblique-slip fault is a special type of fault that forms when movement is not exactly parallel with the fault plane. Oblique movement occurs when normal or reverse faults have some strike-slip movement and when strike-slip faults have either some normal or reverse movement.

Usually, different rock types or rock features (such as quartz veins, mineral layers, or beds) are broken and offset along the fault plane. Faults are commonly marked by debris or breccia that forms when there is movement along the fault plane. Grinding of rock along the fault plane may also produce a clay-like, pulverized rock called gouge. Sometimes, when the fault plane is exposed, there may be grooves, striations (scratches), and asymmetric fractures, called slickensides, that provide visual evidence of movement (Costain and Coruh 1989).

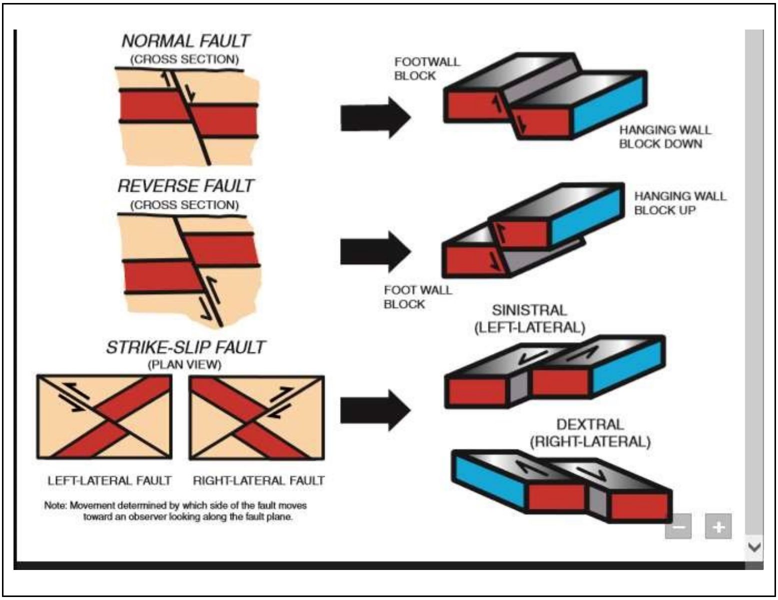

Figure 2.5 Normal, reverse and strike-slip faults (Costain and Coruh, 1989).

2.5 Fractures in Complex Structures

A fracture is any separation in a *geologic formation*, such as a *joint* or *fault*, that divides the *rock* into two or more pieces. A fracture will sometimes form a deep fissure or crevice in the rock. Fractures are commonly caused by *stress* exceeding the rock's strength, causing the rock to lose cohesion along its weakest plane. Fractures can provide *permeability* for fluid movement, such as *water* or *hydrocarbons*. Highly fractured rocks can make good *aquifers* or *hydrocarbon reservoirs* since they may possess both significant *permeability* and fracture *porosity* (Park 2005). Apart from structural complexities, it is also desirable to know whether productive fractures are present in a well that is penetrating a reservoir of very low matrix permeability. Since most of the reservoirs in this basin are comprised of carbonates and have a complex tectonics history, the chances of finding good or bad fractures are quite high in these reservoirs.

Generally, fractures control behavior in the fractured reservoir (Nelson 2001). If the fractures are open, they are the conduits to petroleum migration, resulting in the development of a high production zone with a permeability of more than 10,000 mD. (Rezaei 2006; Haller & Porturas 1998). It appears that the complex interaction of fracture, matrix, and fluids is sufficiently variable to render each fractured reservoir unique (Watts 1983). There are a number of properties that may affect rock brittleness, which includes rock type, grain size, type of cementing mineral, porosity, temperature, clay percentage, effective confining pressure, and strain rate (Stearns and Friedman 1972). Different sources of stress often create different types and distributions of fractures. Fold-related fractures are different from fault-related fractures regarding their relation to the original structural setting, orientation, and distribution. Fractures have been classified into several genetic types (Stearns 1967; Stearns and Friedman 1972; Nelson 1985). Determining the regional stress regime can be complicated by the local variation in stress and the reactivation of older structural elements (Willis 1994). Fractures and faults reveal complex geometry and timing relationships (Scarrott et al. 2010).

Nevertheless, the main challenge is to discover where they are more concentrated in the reservoir and what orientations they have in relation to the structural axis, prevailing stress regime and gas-oil or oil-water contacts. The highest measured values for secondary porosities belong to fractures in the Asmari Formation, which is characterized by significant amounts of vuggy and fracture-filling cement. Fractures facilitate fluid circulation and the subsequent dissolution of allochems and high Mg carbonates. In contrast, fine-grained carbonate facies were less cemented, and thus, porosity enhancement by cement dissolution was insignificant (Shariatinia et al. 2013). Independently from matrix porosity, fracture permeability is also important for high productivity from Asmari.

Therefore, the study of the fractures in the Asmari reservoir is a serious subject (Khoshbakht et al. 2009). By using an FMI log, structural and reservoir geologists can identify fracture features and classify fracture types at the wellbore directly. In the absence of seismic data, they can provide critical information for finding a reliable solution for some major geological problems (Rezaei 2006).

2.6 Permeability in Fractured Carbonate Reservoirs

Carbonate reservoirs account for 40% of today's hydrocarbon production, and because of several giant fields in the Middle East, they are expected to dominate production through the next century. Therefore, understanding carbonate reservoirs and producing them efficiently has become an industry priority and is likely to remain so. Current efforts in carbonate exploitation focus on correctly targeting new wells, frequently horizontal, optimizing production from untouched reserves and ensuring that massive water injection schemes deliver an effective sweep of the reservoir. In support of these efforts, geoscientists are trying to decipher the enigma of carbonate rock's complex pore space and understand how permeability barriers and conduits affect reservoir behavior (Bram et al. 1995). The zones of dissimilar porosity and permeability produced by diagenetic developments are the main keys to the heterogeneous reservoir. The dominant lithology of the Asmari Formation is a gray limestone with a widespread system of fracturing. The non-productive interval occurs where the rock has less than 5% porosity and less than 1 mD permeability (K). The productive intervals generally have porosity ranging from 5 to 25%, with an average of around 12%. Matrix permeability is low, seldom exceeding 2mD. However, the fractures within the pay intervals significantly raise the permeability in excess of 5 darcies, and phenomenal flow rates can be seen in these areas.

The Asmari fracture system is generally well-connected, and pressure responses at the well are dissipated almost instantly over long distances. In addition, the fracture system often connects the Asmari reservoirs with those of the Bangestan Group reservoirs (across 500 m to 1,000 m of shale). In the interconnected zones, the oils are of the same type and have an almost identical composition. The fluid interface in the Asmari and Bangestan reservoirs also move in unison as a result of Asmari production. Even in the relatively low-porosity zones, fractures have resulted in some wells producing over 80,000 barrels per day (bbl. /day). The thick Gachsaran formation (anhydrite/salt) sequence (300 m–1,500 m) overlying the Asmari reservoir rock provides an excellent seal.

Permeability is a challenging factor when assessing a fractured reservoir. Core analysis is a common method to identify the small-scale fractures of the well and permeability and porosity. However, there are some limitations in the core procedure, such as being highly expensive, unidirectional and having a low recovery coefficient in the fractured zone. Thus, in these cases image logs are more useful to study the subsurface fractures (Khoshbakht et al. 2009). Image log data complements core whole data and can reduce the amount of coring required by 75%, resulting in significant savings to drilling programs in terms of project cost and time (Stroble 2009).

Consequently, borehole imaging is considered to be the best technique to identify and measure the orientation of planar geological features in the subsurface. The wireline resistivity image tools are pad tools that measure the formation micro conductivity directly through an array of resistivity buttons mounted on pads that are pressed against the borehole wall. Such tools normally provide the best high-resolution borehole images with conductive (water-based) muds. Examples are the FMS and FMI with an azimuthal resolution of 64 (FMS) vs. 192 (FMI) and capable of radial micro resistivity measurements (vertical resolution 0.2”, vertical sampling: 0.1”, depth of investigation: 30”) (Prensky 1999). On the other hand, in this study, with FMI resistivity, a new technique aims to enhance the matrix permeability profile considerably.

Schlumberger introduced a new approach to utilize borehole electrical images in the analysis of carbonate reservoirs’ porosity system (Newberry et al. 1996 & Akbar et al. 2001). Porosity, permeability and other rock properties could be estimated and classified by analytical and intelligent methods (Masoudi 2014). The high-resolution electrical imaging tool is a key component in understanding and interpreting reservoir geometry at the level of detail required (Shang and Tang 2005). Permeability measurements in most of the reservoirs display strong dependency on the direction. Therefore, it is essential to determine permeability variations in different directions within the reservoirs (Sahin and Ali 2011). In MI25, FMI is used to characterize permeability in the non-fractured reservoirs (the Sarvak Formation) because of its circumferential coverage and high vertical resolution. It can pick up indirect changes in the rock fabric, which could either be depositional or diagenetic in origin. Significant heterogeneity in these reservoirs is found in all dimensions, and predicting reservoir continuity is challenging. The extrapolation of small-scale heterogeneity into uncured wells using a traditional approach is unreliable due to the large vertical resolution difference between cores (actual scale) and conventional logs (averaged responses over a few meters) (Russell et al. 2002). The method of integrating image logs with seismic and dynamic data produced a consistent and confident characterization of stress-induced fracturing and the interpretation of their effects on reservoir behavior. Therefore, it has implications for reservoir management decisions (Sadler 2002). High-resolution log data like dip meters and image logs are required to characterize small-scale heterogeneity, which is essential for a good three-dimensional geological model that predicts true reservoir behavior. In consequence, our research demonstrates a method to increase the reservoir description of the Sarvak Formation by using FMI and OBMI-UBI compared with cores in GS-16 and MI-25.

2.7 Oil-Based Mud Systems in Iran

The type of mud system for running FMS and FMI is water-based mud, and for OBMI and Dual OBMI, oil-based. In most of the fields of the Dezful embayment, it is not possible to drill wells with water-based mud now. Using an oil-based mud system poses many challenges for formation imaging. Even a thin film of non-conductive mud is essentially an opaque curtain, preventing conventional micro-resistivity images from measuring the formation. The presence of non-conductive mud cake or mud filtrate further complicates the situation. Oil-based mud can be expatriated with water-based mud at a significant cost; nevertheless there is no assurance of the measurement. Fracture aperture and porosity are computed by using FMI, but OBMI-UBI cannot support these parameters. Based on this reason, the oil company preferred to run FMI instead of OBMI, and they had to change oil-based mud to water-based mud and change mud effects on the FMI images in the permeable formation. Addressing the need for images in this difficult environment clearly demanded a novel approach, which was implemented in the Iranian fields of the Dezful embayment. The approach used in this part of Iran is comprised of two independent techniques that are used in an integrated way to describe the geological features of formations traversed by the wells. The first technique gives an acoustic (amplitude and transit-time) map of the features exposed to the borehole surface, and the second technique gives the resistivity map of the same features. A combination of oil-based mud imaging tools provided a novel method of formation and characterization in fractured and non-fractured reservoirs (Movahed et al. 2014).

2.8 Borehole Imaging Development and Application

Wireline borehole-imaging techniques were developed much later than the first oil-based mud system. It was not until 1958 that photographic devices deployed by Birdwell were first used to get a glimpse of the rocks within a wellbore. Later, in the 1960s, attempts to retrieve images from the downhole shifted toward the use of television cameras. A significant breakthrough occurred in 1968 when Mobil developed the first high-frequency acoustic-imaging tool, the borehole televiewer. Unlike the optical devices before them, acoustic tools eliminated the need for transparent borehole fluid—clear water, gas or air—and greatly expanded the range of borehole-imaging applications. Efforts launched in the 1980s to make the data more usable resulted in improvements ranging from analog-to-digital conversion and reprocessing capability to digital tools with high-resolution, focused transducers—devices that function as both transmitter and receiver. However, acoustic-imaging devices are extremely sensitive to tool centering, borehole rugosity and mud density and often are insensitive to formation bedding.

In 1986, Schlumberger broke new ground with the first micro-resistivity imaging device, the FMS tool. This tool enabled geologists to observe and analyze formation bedding, fractures and secondary porosity on an image workstation and in greater detail than before. The initial tool included two imaging pads and two dip meter pads (Table 2.1) but could image only 20% of a $7^{7/8}$-inch borehole in one pass; multiple logging passes were necessary to achieve reasonable borehole coverage. In 1988, replacing the two dip meter pads with two more imaging pads doubled the coverage of the original FMS. The push for increased borehole coverage continued as operating companies wanted to see a larger percentage of the borehole in a single pass, especially when imaging high-risk wellbores, heterogeneous or fractured reservoirs or complex carbonate rocks. The FMI, equipped with four imaging pads and four imaging flaps, again doubled the coverage of a single logging pass in 1991. The FMI tool achieved 80% coverage in a $7^{7/8}$-in. borehole (Figure 2.6) (Cheung and Laronga 2002). The quest for greater borehole coverage was not exclusive to Schlumberger.

In 1989, the Bureau de Recherché Geologique ET Minieres (BRGM) developed the 2-in. diameter ELIAS, a 16-pad, micro electrical-imaging tool that achieved 100% borehole coverage in small boreholes. In the 1990s, both Halliburton and Western Atlas achieved 60% coverage in a $7^{7/8}$-in. borehole by employing six-arm designs—the Halliburton electrical micro imaging (EMI) tool in 1994 and the Western Atlas simultaneous acoustic and resistivity (STAR) imager tool in 1995.

In addition to the microelectrical measurement, the Western Atlas tool included an acoustic-imaging sensor. Other acoustic-imaging tools were introduced prior to 1995, including the Halliburton circumferential acoustic scanning tool (CAST) and the Schlumberger ultrasonic borehole imager (UBI) tool (Cheung and Laronga 2002). These acoustic tools have resolution specifications similar to some of the micro resistivity devices, 100% borehole coverage and the potential to operate in OBM and SBM synthetic-base drilling mud (SBM) (Cheung and Laronga 2002).

Despite tremendous advancements, acoustic tools frequently do not assist in the analysis of formation bedding, which is critical to geologists trying to ascertain the structural dip or stratigraphy of a reservoir. Unfortunately, the limitations of acoustic imaging tools restrict their usefulness for the comprehensive evaluation of structures and reservoirs. The growing need of the oil industry for borehole imaging in non-conductive muds became a top priority of Schlumberger's formation-evaluation research and development (R&D) in 1997.

As a result of these efforts, in 2001, Schlumberger introduced the first micro-resistivity borehole imaging tool designed for non-conductive drilling muds (OBM and SBM). A new wireline device, the oil-based mud imager (OBMI), builds on proven methods in resistivity logging and incorporates a unique imaging pad to deliver the industry's first commercial micro resistivity-imaging service for OBM and SBM-filled boreholes (Figure 2.7) (Cheung and Laronga 2001).

This is the only tool in the oil industry today that provides quantitative Rxo (resistivity of an invaded zone) in non-conductive mud (OBM and SBM). OBMI, which is the tool used for resistivity imaging, has the disadvantage of limited borehole coverage. This limitation was successfully overcome by using Dual OBMI in one of the wells in 2010.

In Dual OBMI, two OBMI tools are stacked at an angle of 45 degrees. Thus, there are eight pads in dual OBMI as compared to four pads in the conventional OBMI tool. Each pad acquires five measurements, and the data are displayed as a color image oriented with respect to the geometry of the tool and borehole. In an 8" hole, the borehole coverage with conventional OBMI is 32%, whereas it increases to 64% with Dual OBMI (Figure 2.8).

In addition to wireline borehole imaging, Schlumberger introduced a logging-while-drilling (LWD) borehole imaging tool for conductive drilling mud systems in 1994. Geovision resistivity (GVR), also known as resistivity at the bit (RAB), provides the electrical image of formations at three depths (1, 3, and 5-in.) of investigations. To get the structural dip information while drilling in OBM or WMB, Schlumberger introduced a density and photo-electric factor imaging tool (called Vision ADN675) for 8" holes in 1994. For the boreholes drilled with a 6" bit, Vision ADN475 was introduced in 1996. In 2001, Schlumberger started providing density images in real-time to help geoscientists foster the wells within the target horizons (Table 2.1).

Table 2.1: Significant events in the development of borehole imaging tools.

Year	Borehole Imaging Tools.
1958	Birdwell employed borehole photography using a -16 mm lens.
1964	Shell used a black and white downhole television camera.
1968	Mobil developed the first analog borehole televiewer that was 33/8 in. in diameter.
1971	Mobil developed an analog borehole televiewer that was 13/4 in. in diameter.
1980	Amoco developed a 3 in. Diameter high resolution borehole televiewer that features analog to raster conversion and digital reprocessing of images.
1983	Arco developed a 3 in. Diameter high resolution borehole televiewer that features the digitization of the analog recording and digital reprocessing of images.
1984	Shell developed a 3 in. Diameter high resolution borehole televiewer that features analog to raster conversion and digital reprocessing of images.
1986	Schlumberger introduced the first micro resistivity imaging tool, the FMS, with two imaging pads and two dip meter pads.
1988	Schlumberger introduced the second version of the FMS that has four imaging pads for improved borehole coverage.
1989	Atlas introduced the CBIL borehole imaging service that utilizes dual ultrasonic focused transducers.
1989	BRGM developed the ELIAS tool that provides 100% borehole coverage in small boreholes.
1990	Halliburton introduced the CAST borehole imaging service.
1990	Schlumberger introduced the UBI that also utilizes an ultrasonic, focused transducer and has an increased tolerance of heavier muds.
1991	Schlumberger introduced a micro resistivity imaging tool, the FMI that doubles the borehole coverage to 80% in a 77/8 in.
1992	Schlumberger introduced the ARI Azimuthal Resistivity Imager tool.
1994	Schlumberger introduced the Resistivity at the Bit (RAB).
1994	Halliburton introduced the EMI Electrical Micro Imaging service, a micro resistivity imaging device.
1995	Baker Atlas introduced the STAR tool featuring six imaging arms combined with an acoustic imaging device.
2000	Schlumberger introduced the first micro resistivity tool designed for non-conductive mud (OBMI).
2001	Precision introduced the HMI.
2006	Weatherford introduced the CMI.
2008	Schlumberger introduced Dual OBMI tools.
2009	Halliburton introduced the AFR™ Azimuthal Focused Resistivity Sensor.
2010	Halliburton introduced the OMRI™ *tool* for use in oil-based muds.

Borehole imaging delivers micro-resistivity and acoustic images of the formation in both water-based and non-conductive mud. Borehole imaging is the preferred approach for determining net pay in the laminated sediments of fluvial and turbidity depositional environments.

2.9.1 Water-Based Mud Imaging

The FMI has a four-arm and eight-pad array. Each pad and flap contains 24 buttons to make 192 buttons in total for all four pads and four flaps. The tool includes a general-purpose inclinometer cartridge, which provides accelerometer and magnetometer data. The tri-axial accelerometer gives speed determination and allows the re-computation of the exact position of the tool. The magnetometers determine tool orientation. During logging, each microelectrode emits a passive, focused current into the formation. The current intensity measurements, which reflect micro resistivity variations, are converted to variable-intensity gray or color images. The observation and analysis of the images provide information related to changes in rock composition, texture, structure or fluid content (Figure 2.6) (Shawky 2006).

2.9.2 Oil-Based Mud Imaging

So far, borehole imaging is considered to be the best technique to identify and measure the orientation of planar geological features in the subsurface. The first technique gives an acoustic (amplitude and transit-time) map of the features exposed to the borehole surface, and the second technique gives the resistivity map of the same features. A brief description of the principle used by each technique is given in the following:

2.9.2.1 OBM Resistivity Imaging (OBMI)

Resistivity imaging in OBM is a technique of making resistivity maps of borehole surfaces using laterolog principles of resistivity measurement. This is achieved with a tool called OBMI. It is comprised of four pads on four arms spaced at 90 degrees around the borehole (Cheung and Laronga 2001). On each pad, five pairs of sensors (called voltage electrodes) are placed between the current electrodes, as shown in Figure 2.9. The size of each voltage electrode is 0.4 inches, and they are spaced vertically and horizontally at 0.4 inches from each other, giving the pixels a nominal size of 0.4 x 0.4 inches. The pads are pushed against the borehole wall, where a thin film of non-conductive mud is between the pad face and the formation. In accordance with the four-terminal or short-normal method of measuring resistivity, an alternating current (I) is injected into the formation between the two current electrodes (A and B) at opposite ends of each pad. The potential difference (V) between each of the five pairs of voltage electrodes is measured. From this value, the resistivity of the invaded zone, Rxo, in the small interval of the formation opposite the sensors is accurately and quantitatively calculated using Ohm's law given in Equation 2.1 as follows (Sembiring et al. 2005):

$$Rxo = k \frac{V}{I} \tag{2.1}$$

Where '*k*' is a geometrical factor. This way, five Rxo curves are obtained from each pad and converted into images, which have a vertical resolution of 1.2 inches, this being the thinnest bed for which a reasonably accurate resistivity can be estimated (Borbas et al. 2002). The tool can be run in all typical oil-base mud (OBM) types, from diesel to synthetic. It can provide images for formations with resistivity ranging from below 0.5 ohm-m to over 10,000 ohm-m (Cheung and Laronga 2001). In addition, the calibrated high-resolution resistivity represents the first Rxo measurement in an OBM environment (Figures 2.7 to 2.9).

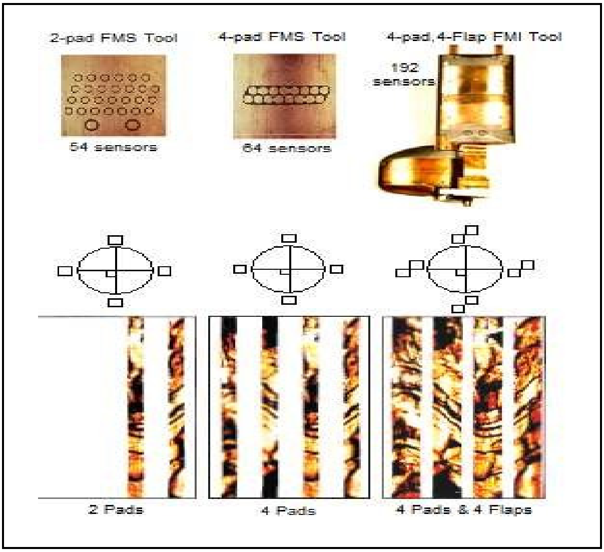

Figure 2.6 Increased borehole coverage over time. As more image data are acquired from around the circumference of the borehole, a more comprehensive interpretation is possible. Schlumberger micro-resistivity-imaging devices have progressively added more sensors and pads to improve borehole coverage (Cheung and Laronga 2001).

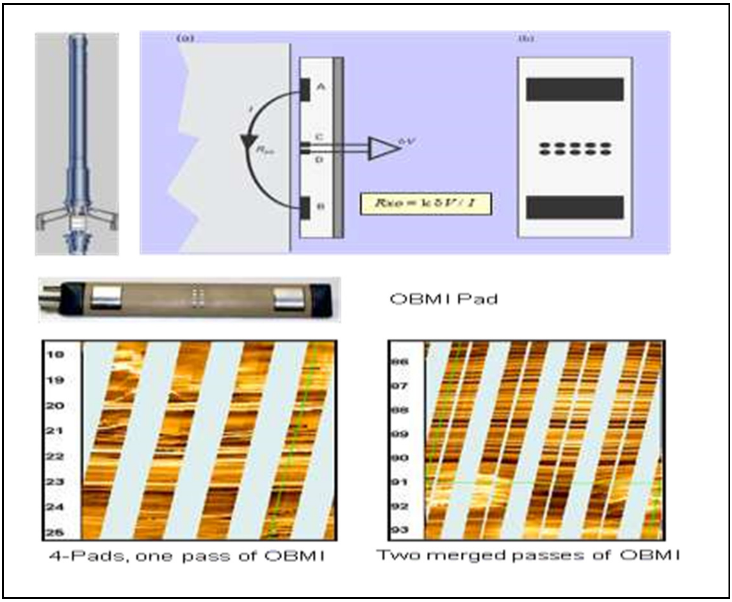

Figure 2.7 Schematic showing (a) side and (b) front views of a pad of OBMI. The tool has four pads; each pad carries five sets of sensors, which measure the voltage drop DV in the formation facing the sensors. To get more borehole coverage, more than two passes can be made that can be displayed together in one track (Cheung and Laronga 2001).