Republic of Yemen
Ministry of Higher Education and
Scientific Research
Emirates International University

الجمهورية اليمنية
وزارة التعليم العالي والبحث العلمي
الجامعة الإماراتية الدولية

EMIRATES INTERNATIONAL UNIVERSITY
FACULTY OF ENGINEERING AND TECHNOLOGY
OIL & GAS ENGINEERING

RESERVOIR CHARACTERIZATION OF QISHN CLASTIC FOR NORTH CAMAAL FIELD, BLOCK-14, MASILA BASIN, YEMEN, USING SEISMIC, WIRELINE AND CORE DATA

A PROJECT REPORT SUBMITTED IN PARTIAL FULFILLMENT OF REQUIREMENTS FOR THE DEGREE OF BACHELOR OF SCIENCE IN OIL AND GAS ENGINEERING

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SUPERVISED BY:

DR. MOHAMMED ABBAS

GRADUATION PROJECT
SANA`A
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Abdullah Hussein		
Islam Almaouri		

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DEDICATION

We dedicate this project to our nation Yemen

ABSTRACT

In this study Qishn reservoir in North Cammal field, Masila basin, Yemen was characterized by an integrated approach using Seismic interpretation, Petro-physical analysis, Core, and engineering analysis to better understand the reservoir properties and oil-in-place. A 3D seismic is used to characterize the reservoir using Seismic inversion, acoustic impedance and a porosity, permeability, formation pressure volumes was generated. Horizon and fault interpretation to was also carried out. Petro-physical analysis was done for Qishn formation to determine total and effective porosity, permeability, shale volume, water saturation and lithology distribution. The properties obtained from the petrophysical study was used to correlate the seismic volumes showing an accuracy with a correction factor of 0.91 in the porosity volume and 0.89 in the permeability volume. Maps was generated for different reservoir properties such as porosity map, permeability map, water saturation map and net-pay map. The volumetric method was used to determine the reservoir oil-in-place with the defined properties from both the seismic and petrophysics study and a STOIIP map was generated for the field. Material balance was also used to calculated the reservoir oil-in-place using production data for the field up to 2012. A good match was observed between the volumetric and material balance calculations. Finally, attractive areas for new wells in the field.

KEYWORDS:

Seismic Inversion, Acoustic Impedance, STOIIP, MBE, Horizons, Structural Maps. Property Maps, Polygon, Boundary.

CHAPTER ONE

1.1 Introduction

Reservoir characterization, in general, is the process of integrating various qualities and quantities of data in a consistent manner to describe reservoir properties of interest at inter well locations. The basic inputs in the reservoir characterization process are the geological, well log data, seismic data, core data and any other data which can be related to this study. The data used for the analysis consist of suites logs for two wells, 3D seismic cube for North Camaal as a whole, core data, and production and injection data for all wells in North Camaal.

Petrophysical properties such as porosity, permeability, net pay and fluid saturation will be defined. These properties are evaluated through well logs of two wells (North Camaal 4, North Camaal 8), seismic inversion, and laboratory core analysis. Porosity and saturation are important inputs to evaluate hydrocarbon-in-place (HIIP), while permeability is used to define if these hydrocarbons will be able to flow. The significance of such properties can also be judged from the fact acquiring formation evaluation data in all development wells to reduce uncertainties both in geologic and reservoir models.

The basic logging data that are used Gamma-Ray (GR), resistivity (LLS, LLD) and

Porosity tools (Density, Neutron and Sonic). The results from formation evaluation well logs are generally validated and calibrated against laboratory core measurements this is especially true for permeability, where a porosity-permeability relation is derived from core measurements and applied on porosity log to get permeability profile.

A general industry practice is to regard core measurements as ground truth. However, there can be uncertainties associated with core measurements especially when laboratory conditions are ignored under which core measurements were made. For example, if logs based total porosity consistently read higher than core porosity, then there is a possibility of core samples not dried enough at given temperature, and measured porosity is effective instead of total porosity (Crain's Petrophysical Handbook, 2000). Similarly, porosity from logs is derived based on mathematical models needing analyst input of formation properties e.g., sandstone matrix density of 2.65g/cc and oil density of 0.8g/cc may not be true to estimate porosity from a density log in an oil-bearing sandstone reservoir. For logs-based formation evaluation, porosity is an input to saturation and permeability equations. Uncertainty in porosity analysis will result uncertainty in estimates of saturation and permeability as well.

Seismic attributes are any measurement derived from seismic data that helps us to enhance or identify features of interest visually.

Seismic attribute may be sensitive to the desired geologic feature or reservoir property of interest directly, or allows us to define the depositional environment or structural and enables us to imply some features or properties of interest (Chopra and Marfurt, 2007).

Genetic inversion technique is used as a method to convert the seismic cube or its related attribute to a corresponding log property.

A derived effective porosity from well logs of the two wells are used to train the data and convert it to the AI and then to porosity cube.

1.2 Aims and Objectives

The aim of this project graduation is conducted to study the Qishn calstic reservoir characterization of North Camal Oil Field in addition to evaluate the hydrocarbon potentialities of the subunits Qishn Clastic reservoir by integrating a variety of data.

To achieve the aim of the project, the following objectives are defined:

- Apply 3D seismic structural and stratigraphic interpretation and integrated with well logs to develop and look for attractive area in the study area.
- Using Genetic Inversion technique as a methodology to study the reservoir characterization with Kingdom Suite software and new technologies and methodologies and using seismic attributes such as coherence or low frequency derived from inversion and other attributes to study the reservoir characterization.
- Estimate reservoir properties such as porosity, shale volume, water saturation and net pay by utilizing petrophysical analysis.
- Use rock physics diagnostics to characterize the reservoir sands in the field.
- Generated structural maps and average porosity map for the area
- Permeability and formation pressure map
- Define the volume of hydrocarbon-in-place using volumetric method and martial balance equation then comparison between two previous methods.
- Propose attractive area for new wells to be drilled.

1.3Problem Statement

Studying any petroleum field to get proper results requires integral efforts both from the engineering department, and G&G department. In this project, works have been done as a team from both the USA for seismic data (University of Austin Texas) and Yemen (Emirates International University) to characterize the oil reservoir in North Camaal field in Masila basin Yemen.

The petroleum industry is facing a future where new technologies, Creativity, and integration of different disciplines are at the core of focus for higher exploration and development success rates and improved oil recovery. Reservoir characterization is one of the most important steps in exploration and development phases of any prospect. **It combines the results of different analyses to reduce the risk and uncertainties and to enhance understanding of reservoirs and detect hydrocarbons has become more reliable.**

In this study an integrated approach; seismic analysis, petrophysical analysis, engineering analysis and core analysis to understand and to characterize the reservoir much better compared to any other single technique.

1.4 Geology of Yemen

1.4.1 Geologic Setting

The Republic of Yemen located in southwest Asia, in the southern part of the Arabian Peninsula. Geological surveying and petroleum exploration in Yemen date back to the early decades of the 20th century from the 1930s–60s, the Iraq Petroleum Company conducted exploration1 in the Hadramout and Mahrah areas in north-east Yemen, during which period Ziad Rafiq Beydoun (1924–1998) pioneered geological studies of the country. During the 1970s and 80s both North and South Yemen began offering concession blocks to a number of foreign oil companies. The first commercial discovery came in 1984 when the American company Hunt Oil drilled Alif-1 in the Marib sector of the onshore Sab'atayn Basin in North Yemen, in the Alif Member of the Sab'atayn Formation (Middle–Upper Tithonian age). Twelve onshore and offshore sedimentary basins have been identified in Yemen, categorized into three groups based on the geological era in which they Originated: Paleozoic, Mesozoic and Cenozoic as shown in Table 1.1. The Sedimentary Basins of Yemen shown in Figure 1.1. (1) Rub' Al-Khali (2) Sana'a (3) Suqatra (4) Siham-Ad-Dali' (5) Sab'atayn; (6) Balhaf; (7) Say'un-Masilah (8) Jiza'-Qamar (9) Mukalla-Sayhut (10) Hawrah-Ahwar. (11) Aden-Abyan (12) Tihamah. of These, Only Two,

Geological Ear	Basins
Paleozoic Basins	Rub' Al-Khali Basin. San'a Basin. Offshore Suqatra (Island) Basin.
Mesozoic Basins	Siham–Ad-Dali Basin. Sab'atayn Basin. Say'un–Masilah Basin. Balhaf Basin. Jiza'qamar Basin.
Cenozoic Basins	The Aden–Abyan Basin. Hawrah–Ahwar Basin. Mukalla–Sayhut Basin. Tihamah Basin.

Table 23.1 Paleozoic, Mesozoic and Cenozoic

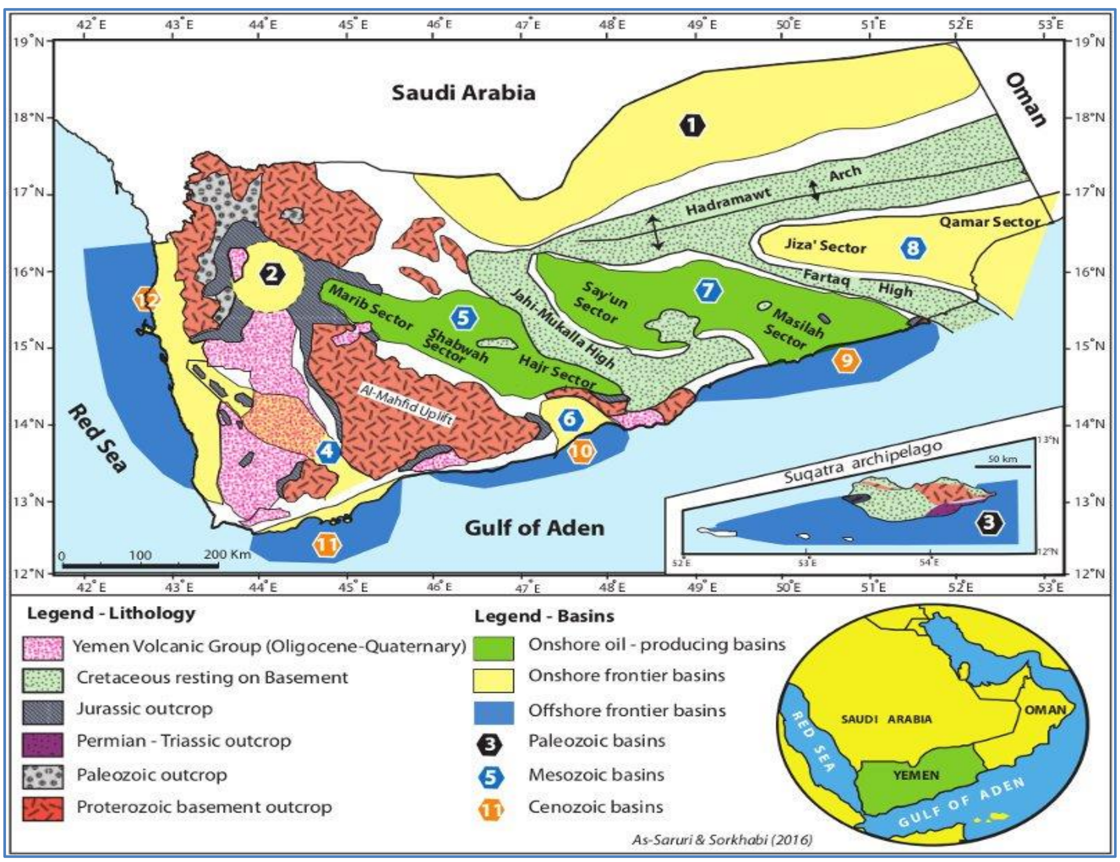


Figure 1.1 The Sedimentary Basins of Yemen

Sab'atayn and Say'un-Masilah basins, are well explored and produced hydrocarbon; the rest remain frontier basins. The two explored and produced basins occurs in two rift basins in Yemen. In western Yemen, petroleum is generated and produced in the Ma'Rib–Al Jawf / Shabwah basin, and in eastern Yemen in the Masila-Jeza basin. These eastern and western basins are largely separated by a structural high known as the Mukalla or Jahi-Mukalla High (figs. 1).

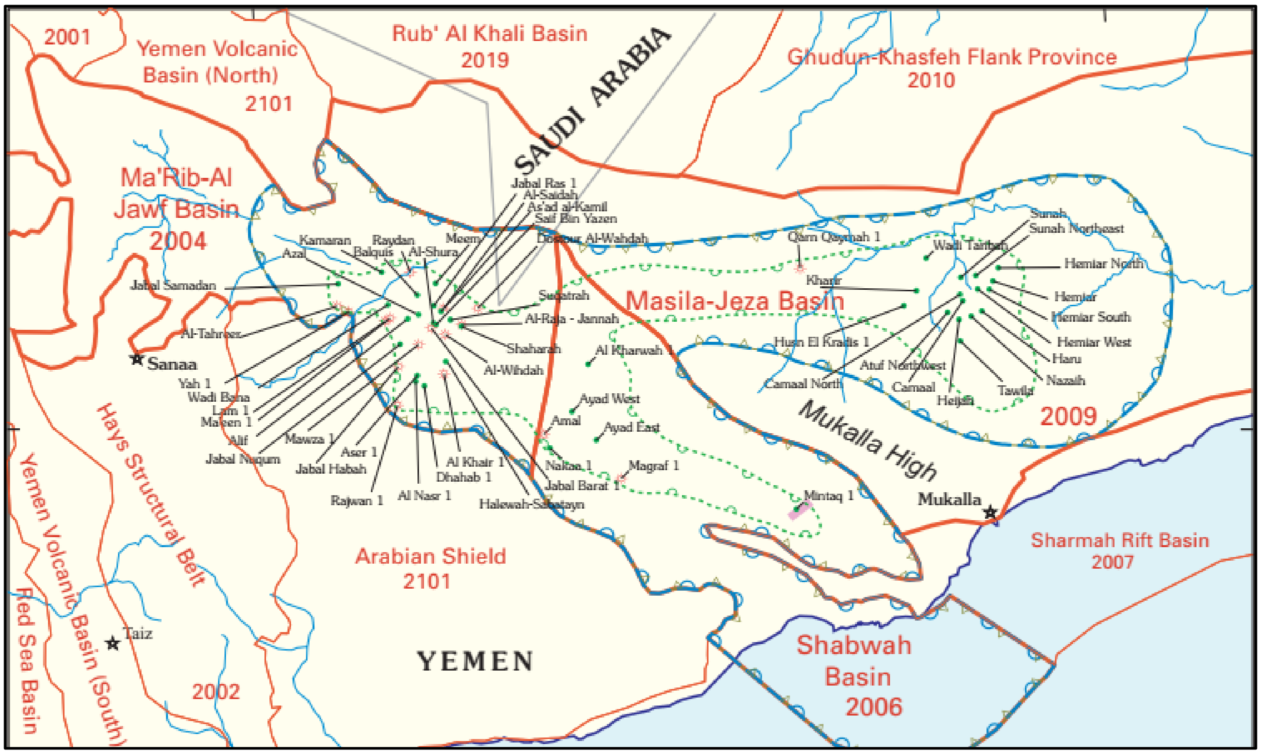


Figure 1.2 map

The western basin is known by a variety of names such as Sabatayn, Marib-Shabwa-Hajar (Beydoun and others, 1998), and Marib-Shabwa basin (Brannin and others, 1999; Csato and others, 2001). Similarly, the eastern basin is also known as the Sayun al Masilah and Jiza-Qamar basin (Beydoun and others, 1998), Sayun basin, and Sir-Sayun basin (Csato and others, 2001). These basins are part of a system of major rift basins, and various authors have used a variety of names for both the main basins and the sub-basins or grabens that occur within them. The names used herein attempt to represent the major petroleum basins or sub-basins within the three provinces included in the Madbi Amran / Qishn Total Petroleum System.

Although the petroleum-bearing grabens are considered to be of Late Jurassic age, their origins can be traced back to Precambrian fault systems. During

Precambrian time, the area underwent a major collision and terrane accretion from about 955 to 615 million years ago (Ma), when older magmatic assemblages (≈2.95–2.55 billion years old) accreted with younger magmatic, volcanic, and plutonic rocks (Husseini, 1989; Whitehouse and others, 1998). However, during the Infra-Cambrian (≈615 to 580 Ma), the southern Arabian peninsula became extensional with intrusions of alkali-rich granites and volcanics as well as development of salt-filled extensional basins. These rift basins were related to major wrench-fault systems such as the Najd, in the western Arabian Shield, which consists of a series of northwest-southeast-trending left-lateral fault zones as much as 1,100 km long and 300 km wide (Husseini and Husseini, 1990; Ellis and others, 1996). The presence of 400 m of Infra-Cambrian syn-rift sediments and metasediments in Yemen (Beydoun, 1997) and the known hydrocarbon occurrence related to Infra-Cambrian salt basins in nearby Oman (Husseini and Husseini, 1990; Pollastro, 1999) led to early exploration efforts that focused on the potential of an Infra-Cambrian petroleum system.

Exploration in the 1980's, however, demonstrated that the Infra-Cambrian sediments were not petroleum bearing, but that petroleum potential existed in rocks, rifts, and structures of Late Jurassic age. The orientation of the Jurassic rifts is likely inherited from the Infra-Cambrian Najd wrench faults, which were reactivated during the Jurassic breakup of the Gondwana supercontinent. The petroleum-bearing grabens of Yemen are interpreted to be the result of a failed arm of a triple junction that occurred in Late Jurassic time (Kimmeridgian) (Greenwood and others, 1980; Husseini, 1989; Jungwirth and As-Sururi, 1990; Schlumberger, 1992; Redfern and Jones, 1995, Csato and others, 2001). Kimmeridgian source rocks and Jurassic-age petroleum systems are important worldwide, particularly within extensional basins such as the North Sea (Ahlbrandt and others, 2000).

Following Jurassic rifting, sediments filled the resulting grabens from earliest Cretaceous (Berriasian) through Late Cretaceous time. A second phase of rifting and associated transpressional and transtensional structures were related to the opening of the Red Sea and the Gulf of Aden during Oligocene and Miocene time (Beydoun, 1989; Haitham and Nanai, 1990; Bott and others, 1992; Crossley and others, 1992; Huchon and others, 1992). During this rifting, sea-floor spreading separated Arabia from Africa and the Arabian plate rotated in a counterclockwise direction. Tertiary petroleum systems of the Red Sea are largely within the rift sequence, whereas petroleum potential in the Gulf of Aden is thought to be largely in the pre-rift sequence. The Gulf of Aden is cut by a series of northeasttrending transform faults that reflect the oblique motion of the Arabian plate from the Gulf of Aden; the Red Sea rift and related structures formed mostly in response to plate movement perpendicular to the ocean spreading center. In Yemen, the southern portion of the Shabwah basin (known as the Balhaf basin) and much of the Masila-Jeza basin (specifically the Hadramawt Arch) are also related to transtensional and transpressional forces during the Tertiary rifting event (Bott and others, 1992; Richardson and others, 1994; Csato and others, 2001).

1.4.2 Petroleum System

1.4.2.1 Source rocks and oil

Within Yemen, geochemical data from 12 oils are reported in the GeoMark (1998) oil database. Seven oils are from Jurassic reservoirs in the Ma'Rib–Al Jawf / Shabwah basin; of these, six samples are from Alif, Azal, and Shabwah fields, and one sample is from an oil seep. Three oils are from Jurassic and Cretaceous reservoirs in the Masila-Jeza basin (Sunah, Hemiar, and Camaal fields; fig. 1), and two other samples are from Tertiary reservoirs in the Gulf of Aden. Although three groupings of oil were identified, oils from Jurassic reservoirs are dominant in both basins. The nine Jurassic-reservoir oils (seven from the west, two from the east) are genetically similar. API gravities range from 29° to 35°, sulfur content from 0.09 to 0.59 percent, and pristine / phytane ratios from 1.46 to 1.72. Biodegradation is suspected in the seep sample from the western basin due to its low API gravity of 14°, high sulfur content of 6.3 percent, and low pristine / phytane ratio of 0.3. The Cretaceous oil sample from Hemiar field in the eastern basin is distinct from all other oil samples, perhaps due to biodegradation; its gravity is lower (22.2°), and sulfur content is higher (1.23 percent), but its pristine / phytane ratio of 1.69 is within the range of the Jurassic samples. The Gulf of Aden Tertiary oils are also different, in that they have high pristine / phytane ratios, 2.02 to 2.92, and reduced δC13values (<–24) as compared to all other samples whose δC13values range from –26 to –28.3. Some oil from the Gulf of Aden is anomalously high gravity, as much as 43°, as noted by Beydoun (1989). These data indicate that the onshore oils in Mesozoic rocks dominantly belong to one genetic oil family, although biodegradation is suspected in the seep and Hemiar samples. The offshore, Gulf of Aden oils reservoir in Cenozoic rocks are from a different oil family.

The source of hydrocarbons from the Madbi Amran / Qishn TPS is believed to be Upper Jurassic Madbi (Kimmeridgian age) shales. Petroleum-migration modeling in the deeper western basin demonstrates the effectiveness of Madbi source rocks and the thermal immaturity of Tithonian Nayfa (Naifa) source rocks (Csato and others, 2001). Csato and others (2001) reported thermally mature Madbi Formation in the Lam and Maabir-Meem members to contain source rocks with total organic carbon (TOC) ranging from 1.4 to 3.6 weight percent, hydrogen indices (HI) of 180–370 and TMAX values ranging from 224°C to 229˚C. Brannin and others (1999) reported TOC values of 2–5 percent and HI's of 580 for the Madbi Formation in the western Yemen basins, and reported as much as 12 percent TOC (Rock Eval) in the pre-rift Shuqra Formation with HI greater than 300. Thermal maturation of Madbi source rocks is believed to commence with oil generation at about 2,700 m (Csato and others, 2001). Thermal maturation modeling shows that with high heat flow, Madbi source rocks may have expelled oil from 135 to 90 Ma, and with low heat flow, from 85 to 50 Ma (Csato and others, 2001). Both models apply inasmuch as a variety of structural configurations and variable heat flow exist within and among the basins. Essentially, oil generation commenced in the Late Cretaceous following deposition of significant post-rift clastics of the Tawilah Group.

In summary, the Kimmeridgian shales of the Madbi Formation are probably the principal source rocks in both the eastern and western onshore basins of Yemen. One total petroleum system was identified and assessed for both basins (fig. 1.2).

1.4.2.2 Reservoir rock

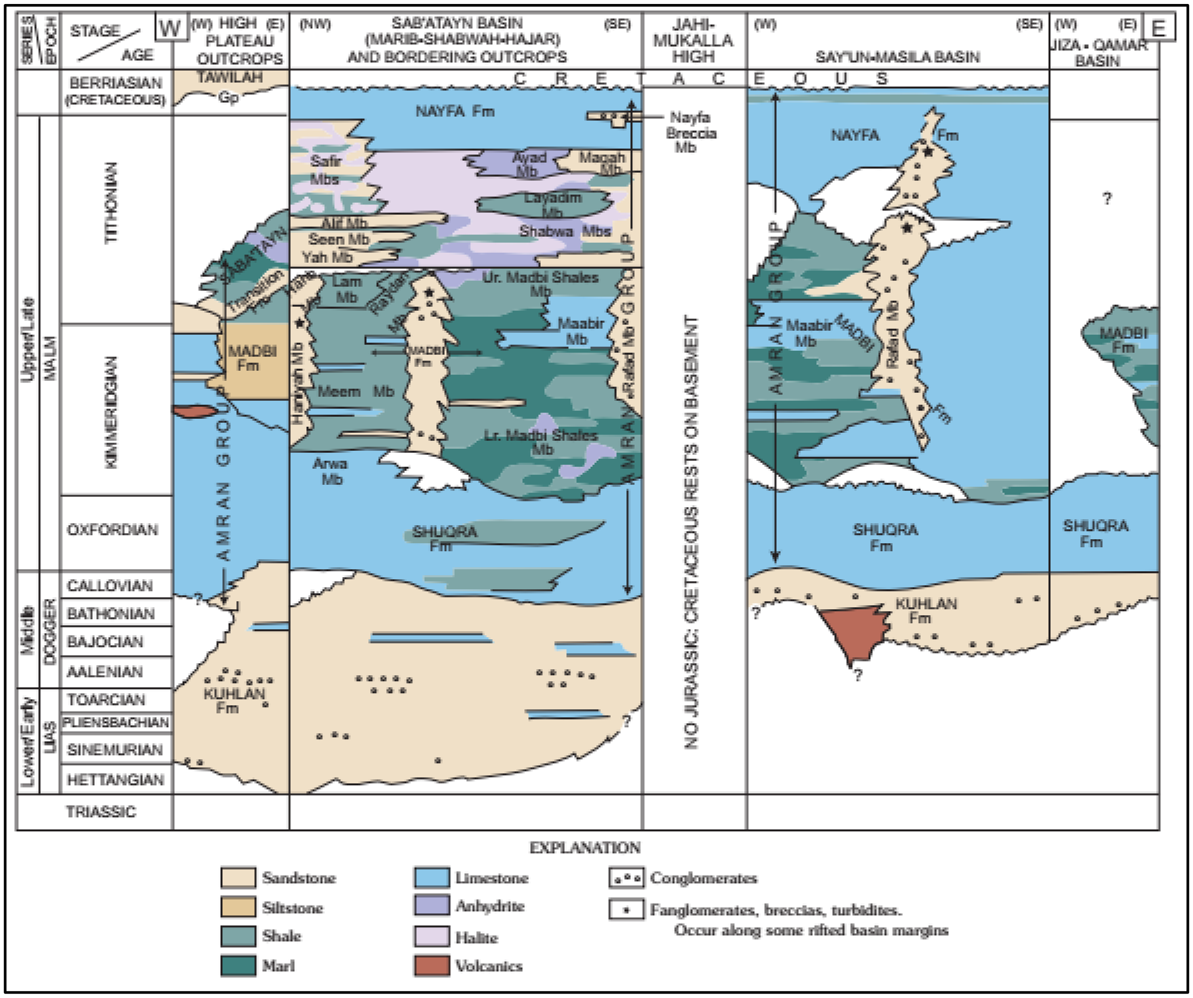


Fig 1.3: Jurassic lithostratigraphy, correlations, and spatial stratigraphic distributions for Yemen (modified from Beydoun and others, 1998). Queried where uncertain.

Reservoirs in the two basins are dependent primarily on the presence or absence of the Upper Jurassic (Tithonian) salt of the Sabatayn Formation (Shabwah Member) (fig. 1.3). In the western Ma'Rib–Al Jawf / Shabwah basin, reservoirs beneath the salt consist dominantly of clastics deposited either along the margins of the various grabens (Hayniyat and Rafad Members, fig. 1.3) or as turbidites (Meem and Lam Members) in the deeper portions of the grabens (figs. 1.3). The upper part of the Jurassic Amran Group and its coarser clastic units, Alif, Seen, Yah, and Safir Members of the Sabatayn Formation, are the principal reservoirs in the western basin (fig. 1.3).

The Madbi Amran / Qishn Total Petroleum System takes its name from the Madbi Formation source rocks and the Amran Formation (Jurassic Tithonian) carbonate and clastic reservoirs in the western basin beneath the salt and the Qishn Formation (Cretaceous Berriasian) clastic reservoirs in the eastern basin where no salt is present. Reservoirs in the western basin are relatively shallow, with depths ranging from 1,829 to 2,286 m (from 6,000 to 7,500 ft) in the west (Petroconsultants, 1996). Initially, much of the production was established in Jurassic carbonate intervals; however, production from sandstones became more dominant as the fields were more fully developed. Porosities for the sandstones generally range from 15 to 28 percent, with permeabilities ranging from 80 millidarcies (mD) to 4 darcies. Most Jurassic sandstones have permeabilities in the several hundred millidarcy range, and commonly in the one-half darcy range (Petroconsultants, 1996). Some reservoirs have lower porosities resulting from halite cement present in the pores, and some production problems are related to salt precipitation and salt production in the western basin reservoirs (Schlumberger, 1992).

Reservoirs in the western basin were charged by vertically migrating hydrocarbons that were trapped beneath a salt seal formed by the Shabwah Member of the Sabatayn Formation (fig. 1.3). Halokinesis in the western basin commenced in Early Cretaceous time and strongly influenced reservoir distribution there. Thickness of these formations and members changes abruptly, depending upon their position relative to the horsts and grabens in the basins and their relations to salt dynamics (thin over diapirs, thick in salt removal areas). The Jurassic syn-rift fill is as much as 4 km thick in the western basin, and individual coarse clastic intervals along some rift margins are as much as 900 m thick (Brannin and others, 1999). Thus, some individual reservoirs may be several hundred meters thick, but thin abruptly across intervening horsts. Turbidite reservoirs and basin margin clastics are also important syn-rift reservoirs that intercept and trap hydrocarbons generated from the deep marine source rocks of both the Meem and Lam Members of the Madbi Formation. Fractured rocks of the Maabir Member also have produced hydrocarbons, as have the pre-rift successions of the Shuqra (carbonate) and Kuhlan (clastic) Formations. Reservoirs in these latter two formations are secondary and generally of poorer quality relative to the Upper Jurassic reservoirs (Brannin and others, 1999).

In the Masila-Jeza basin, the Upper Jurassic salt is absent and the principal reservoir and trapping conditions exist in the transgressive Qishn Formation (fig. 1.4), which may be as much as several hundred meters thick. The principal reservoirs occur within a 75-m clastic interval of mixed sands and shales underlying a carbonate facies (Putnam and others, 1997) that forms a seal for Madbi Formation hydrocarbons migrating vertically as shown in. The eastern basin reservoirs are shallower than those in the western basin with producing depths of about 1,524 m at Camaal, Heijar, Heimar, Haru, Suna, and Tawila fields (Petroconsultants, 1996; Putnam and others, 1997; fig. 1.3). Reservoir quality for Qishn clastics is excellent. At Camaal field, all Qishn reservoirs exceed 23 percent porosity with permeabilities exceeding 1 darcy (Putnam and others, 1997). Petroconsultants (1996) also reported high porosity and permeability values for the eastern basin Qishn sandstone wells. In the eastern basin, tectonic rejuvenation related to Tertiary rifting caused remigration and breaching of preexisting Jurassic reservoirs. Extensive leakage must have occurred as heavy oil belts are known to occur on the margins of the Qishn reservoirs (David Boote, oral commun., 2000)

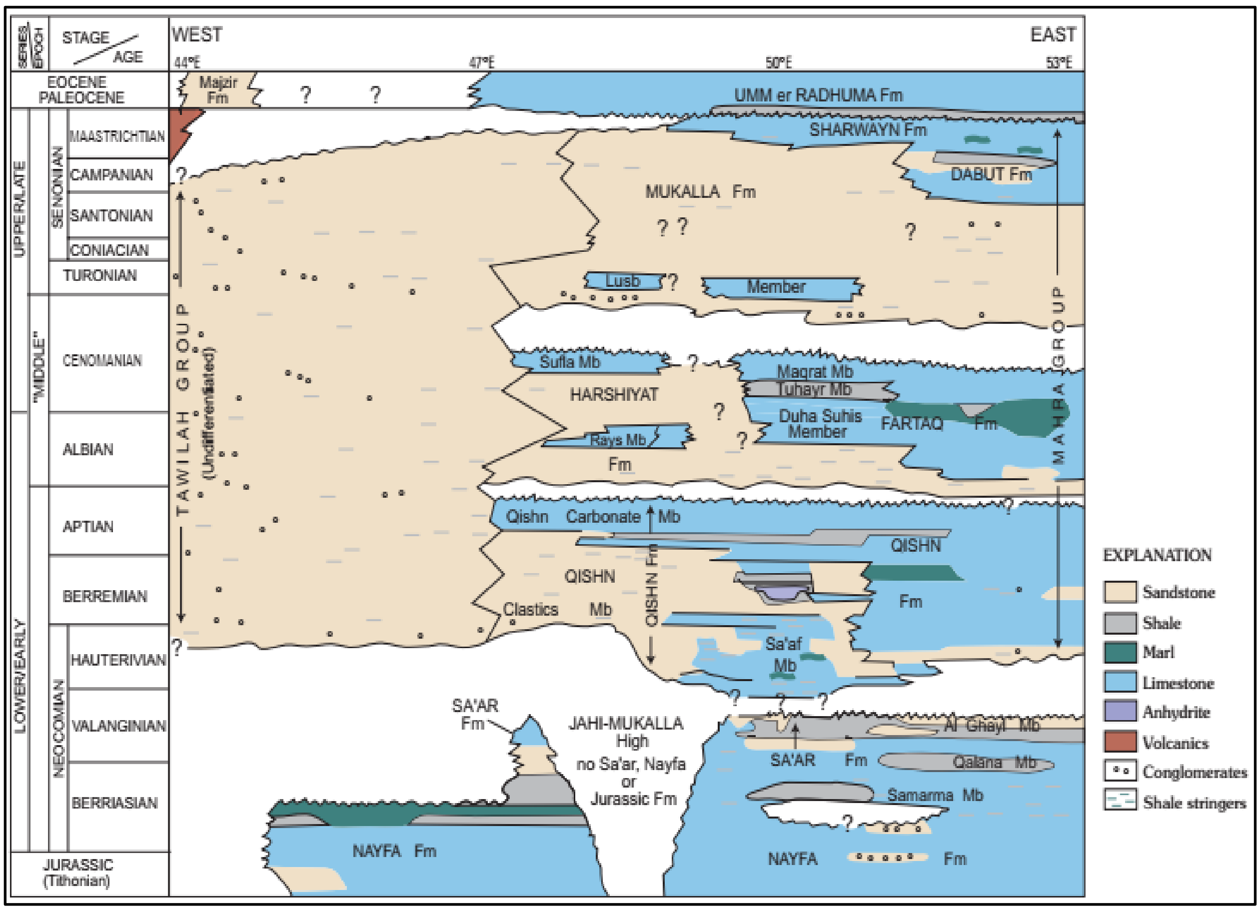


Fig 1.4: Jurassic lithostratigraphy, correlations, and spatial stratigraphic distributions for Yemen (modified from Beydoun and others, 1998). Queried where uncertain.

1.4.2.3 Seal Rock

Salt in the Shabwah Member (Tithonian) of the Sabatayn Formation forms the seal for the reservoirs in the Ma'Rib–Al Jawf / Shabwah basin (Seaborne, 1996). Salt sequences as much as 30 m thick have been observed in outcrops, but in places where the bases were not exposed (Beydoun and others, 1998). Brannin and others (1999) reported Sabatayn Formation salts as much as 1,500 m thick in the Amal field (fig. 1.3). The salt was mobilized shortly after deposition of the Nayfa (Naifa) Formation during Early Cretaceous time. Differential loading on the salt during sedimentation, as well as uplift of the Mukalla high, volcanism on the basin margins, and tilting of fault blocks associated with these activities, contributed to salt instability. The thickness of overlying formations, particularly the Nayfa and Qishn Formations, and Tawilah Group, is dependent on salt movement, thicker where salt withdrew and thinner over diapirs.

In the Masila-Jeza basin, the salt is absent; thus, hydrocarbons generated from the Jurassic rifts migrate upward until they are trapped generally within the Qishn sandstone reservoirs beneath the Qishn carbonate unit. The presence of degraded oils and heavy oils in some of these fields indicates that the seal in the eastern basin is less effective than the salt seal to the west.

1.5 Study Area

1.5.1 The Masila Basin

Masila Basin is one of the onshore basins in Yemen, which is located in the east part of Yemen. The Masila Basin is classified as large hydrocarbon basins in Yemen and contains several, well known hydrocarbon oil fields.

The Masila Basin is one of the Mesozoic sedimentary basins of Yemen (Fig. 1.5), and was formed as a rift-basin linked to the Mesozoic breakup of Gondwanaland and the evolution of the Indian Ocean during the Jurassic and Cretaceous. Mesozoic and Cenozoic units are widely exposed in the sedimentary basins of Yemen. The definition of the lithostratigraphic units in the Masila Basin including North Camall oilfield have been studied by many authors such as Hatitham and Nani, Al Areeq , Beydoun et al , Bosence et al. , Putnam et al. , Holden and Kerr , Watchorn et al. , Cheng et al. , Brannan et al. and Leckie and Rumpel . The stratigraphic section of the Masila Basin including studies North Camall oilfield in age from Precambrian to Tertiary (Fig. 1.5) Basement complex rocks of Precambrian age underlie the Jurassic rocks at a sharp unconformity surface. They consist of granite, diorite and metamorphic rocks. The Jurassic units comprise clastic, carbonate and argillaceous sediments. The lower part of the Jurassic is composed of sandstone and limestone (Kohlan and Shuqra Formations). Here, the Kuhlan and Shuqra are regarded as a discrete prerift package. The Kuhlan Formation is predominantly clastic with local basement topography commonly providing the provenance of sediment. This formation includes fluviatile and arkosic red beds that grade upward into a shallow-marine facies and represents the early transgressive phases of the middle Jurassic seas. These continental rocks are overlain by shallow-marine fossiliferous carbonates such as the Shuqra Formation (Fig. 1.5). The Shuqra Formation conformably overlies the Kuhlan Formation with a gradational contact. This conformable relationship reflects the gradual transgression and a slight deepening of marine conditions corroborating the evidence for a tectonically quiescent platform. The Shuqra Formation is a neurotic limestone with richly fossiliferous marls and does not contain potential source beds. conformably underlies the Madbi Formation (Fig. 1.5). During the late Jurassic commencing in the Kimmeridgian, syn-rift sediments of the Madbi Formation were deposited.

The lithofacies of this unit reflects openmarine environment and can be divided into two members. The lower member, Madbi limestone, is composed mainly of porous limestone, shale layers, with basal sand that forms a good reservoir in some oilfields of the Masila Basin. The upper member is called Madbi shale that is composed of laminated organic-rich shale and mudstone and considered to be the most prolific oil-prone source rock in the basin. During the latest Jurassic to early Cretaceous time, the rifting system of the Masila Basin continued, but the subsidence became slower.

It was accompanied by the accumulation of carbonates in shallow-marine shelf deposits (Naifa Formation). The Naifa Formation consists mainly of silt and dolomitic limestone and lime mudstone with wackestone. The Cretaceous units comprise the Qishn, Qishn, Harshiyat, Fartaq, Mukalla and Sharwayn formations (Mahara Group) (Fig. 1.5). The Qishn Formation is mainly composed of limestone and dolomite, with mudstone and sandstone intercalations. The Qishn Formation was deposited during transgression in Early Cretaceous time. The Qishn Formation conformably overlies the Naifa Formation and unconformably underlies the Qishn Formation. The Qishn Formation consists mainly of limestone, with shale and minor carbonate interbeds, deposited in braided river channels, shoreface and shallow-marine settings as predominantly post-rift sediments.

The Cretaceous Qishn Formation in the Masila Basin has a variety of usage of the various operating oil companies and authors. Redfern and Jones interpreted the Qishn Carbonate Formationss as being age-equivalent of the Biyadh Sandstone of Saudi Arabia. They also identified a clear overall transgressive signature through the Qishn Carbonate Formationss and noted that the upper part of the formation typically consists of carbonates. A down-systems-tract facies change from coarse grained clastic deltas in the west to shale and limestone dominated successions farther east was recognized by Redfern and Jones, Holden and Kerr and Brannan et al. The Qishn Carbonate Formations underling the Qishn Carbonates, which comprises carbonate rocks with red shale beds at the base and represented the proven seal rock in the Masila Basin (Fig. 1.5)

The Qishn Carbonate sediments were deposited in deep water under alternating open and closed marine conditions. The Tertiary units comprise homogeneous argillaceous, detritus carbonates and hard, compacted, massive and bedded dolomitized fossiliferous limestone with local chert nodules (Umm Er-Radhuma Formation) that changes to shales with minor limestone bands in the upper levels (Jeza Formation). [PEPA].

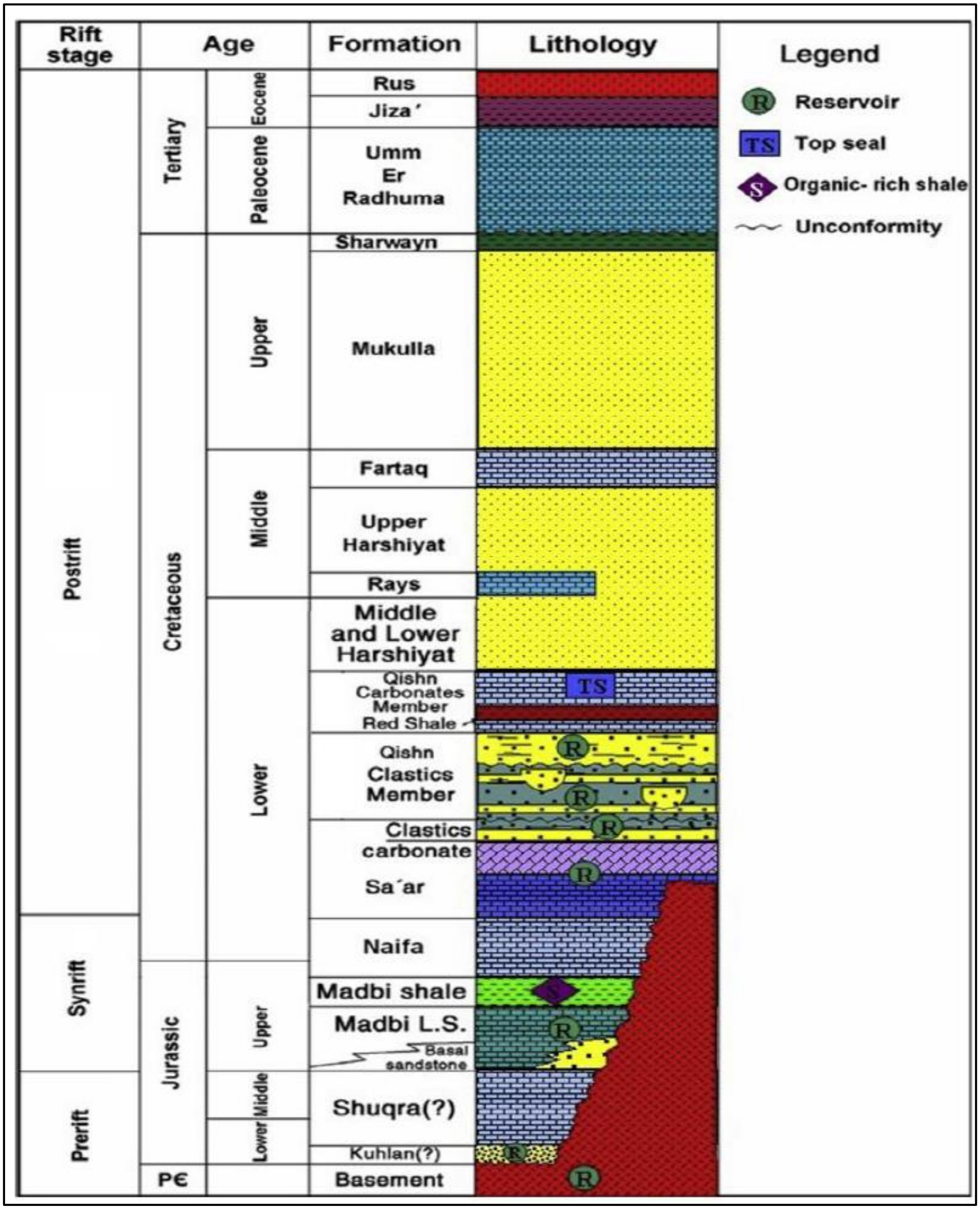


Figure 1.5 The Cretaceous Qishn Formation in the Masila Basin

1.5.2 Block-14

Block 14 is operated by Canadian Occidental Petroleum Yemen Petro Masila now and is located in the Hadhramaut region, in east-central Republic of Yemen. Oil was first discovered on the Block in late 1990 with Commerciality declared in late 1991. Oil production at Masila began in July 1993. There are now 14 known fields containing 56 pools within the Masila Block. Total proved ultimate recoverable oil reserves are approaching 900 million STB. Proven, probable and possible reserve estimates are in excess of one billion barrels of recoverable oil (AAPG Annual Meeting, 2001).

The Masila fields are in the Jurassic- to Lower Cretaceous-aged, Saar Graben. Almost 90% of the Masila reserves are reservoir in the Lower Cretaceous Upper Qishn Clastics Member of the Qishn Formation. Oil is also found in at least seven other reservoirs consisting of Lower Cretaceous and Middle to Upper Jurassic age clastics and carbonates as well as fractured granitic basement (AAPG Annual Meeting, 2001).

This discussion focuses on the main producing horizon; the Upper Qishn Clastics Member. The Upper Qishn represents an upward transgressive sequence from braided river deposits into tidally influenced shorelines, overlain by subtidal and shelf deposits. The Qishn reservoir sandstones have both high porosity (18-21%), and high permeability (<10 Darcies). They are relatively homogenous and continuous in the lower section and are more heterogeneous in the middle-upper section. The uppermost marine sandstones are more mature and very homogeneous. The major field accumulations are tilted, normal, fault block structures located over basement paleo highs, and are dependent upon juxtaposition against overlying Qishn carbonates. The carbonate-dominated pre-Qishn section, including the source rock, is not present on the paleo-highs, and is thickest in the basement lows. The main identified source rock is the Madbi Shale, a Type II marine source which is mature in ‘kitchens’ adjacent to the structural highs. Secondary oil migration occurred upward along fault planes to the overlying traps.

Seismic acquisition in the Masila block has been difficult and expensive because of the remote location, rugged topography and rocky desert terrain. The land surface is incised by deep, wadis or canyons. To date, four 3D seismic programs totaling 162 mi^2 (414 km^2), and 1,415 miles (2,264 km) of 2D data have been acquired. Processing and interpretation problems are significant due to a low velocity surface layer, scattered seismic energy, poor signal to noise ratio from numerous canyon walls, and to “fault shadow” velocity anomalies overlying many of the tilted fault block culminations (AAPG Annual Meeting, 2001).

The biggest production challenge in these fields is water handling. Much water is produced along with the oil, due to a combination of medium gravity (15-33 API^{o}) moderate viscosity oil, high reservoir permeability and a strong regional acquifer. The Upper Qishn oil is undersaturated in gas (average GOR is 3 to 7 SCF/bbl) requiring electric submersible pumps to provide sufficient artificial lift for the large volumes of produced fluid (AAPG Annual Meeting, 2001).

At end of December 1999, the daily production rate collectively for all fields was 210,000 STB/D, with 680,000 BWPD and 6.5 MMCF/D solution gas. Cumulative oil production is over 400 million STB. Initial average well oil production rates vary by producing zone, but fall in a range of 1500 to 15,000 STB/D, with many wells producing from more than one reservoir zone with minor commingling (AAPG Annual Meeting, 2001).

Oil and water are produced in the fields, transported via pipeline to the Central Processing Facility (CPF), where most fluid separation occurs. Increasingly, separation of oil and water is being performed at individual fields using hydro cyclones before entering the CPF. Produced water is re-injected into the reservoirs. The clean oil is moved to the southern coast via an 85 mile long (140 km) 24” pipeline. Export oil is then loaded onto offshore tankers, via a Single Buoy Mooring system (SBM) located 1.25 miles (2 km) offshore, near Mukulla. (AAPG Annual Meeting, 2001).

1.5.3 North Camaal Field:

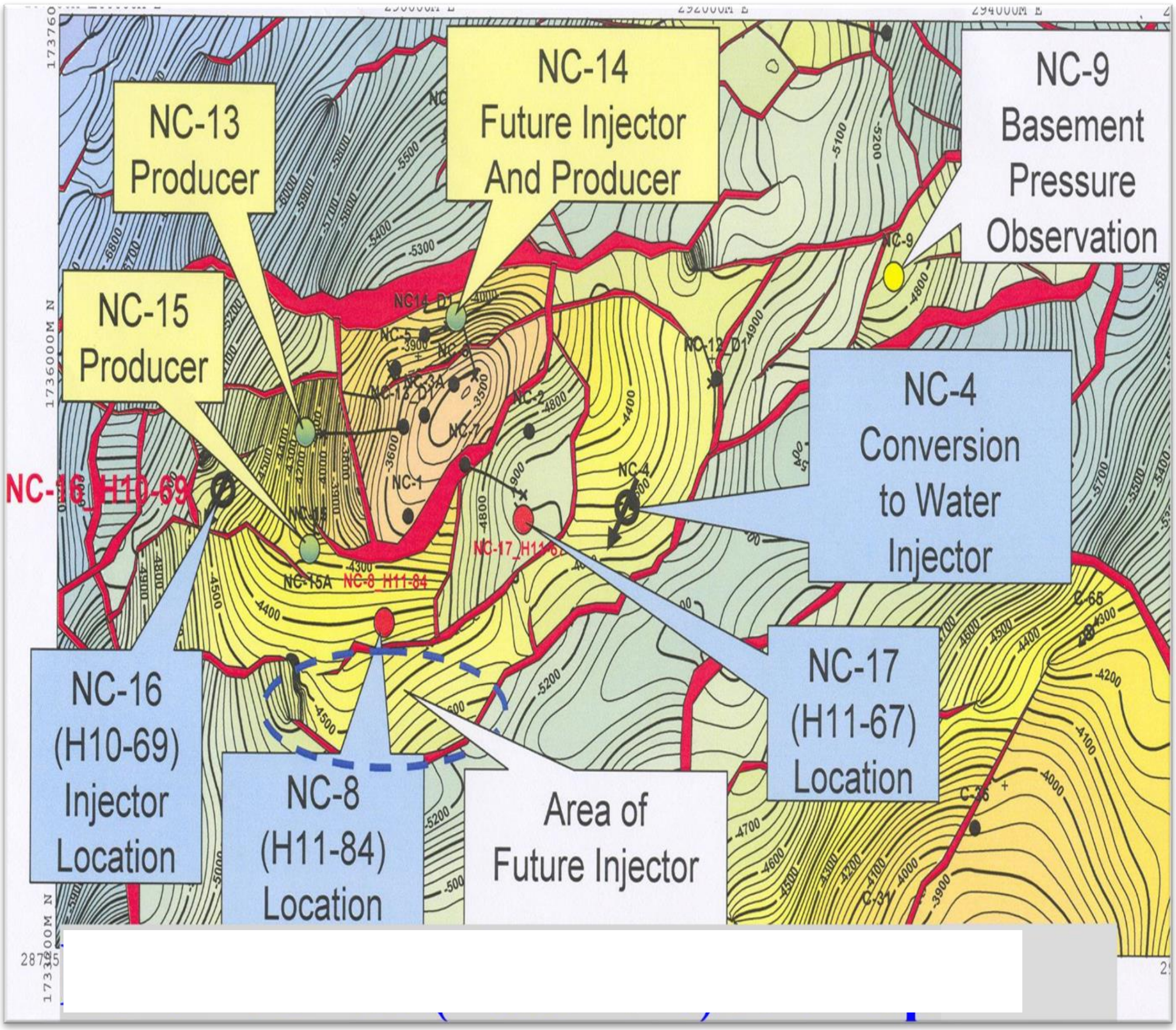


Figure 1.6 North Camaal structure and well locations. Source (Unpublished report of Block-14, 2012)

1.5.3.1 Overview of North Camaal Field:

The North Camaal oilfield is one of the productive oilfields in the onshore of Block-14 in the Masila. The structure map of the field showing the well locations is shown in Fig. 1.6

North Camaal was first discovered on May 1992, and since then several exploration wells has been drilled until it was finally started producing on July 1993. Water was first injected in 2004 and infill drilling has been continued since then. The field is now under Water injection (secondary recovery), and water cut of more than 50% increasing with time.

The early Cretaceous Qishn Formation Sandstone is an important hydrocarbon (oil) main reservoir in the North Camaal field.

Qishn sandstone reservoir is divided into three main units named S1, S2, and S3. S1 is main hydrocarbon-bearing unit which is further subdivided into three sub-units, i.e. S1A, S1B and S1C. S1A and S1C subunit attain the best hydrocarbon saturations and in same time S1A zone is the best petrophysical and reservoir quality properties and higher hydrocarbon content.

The produced oil at North Camaal oilfield is light oil and has a specific gravity between 32 API. The source rock is Upper Jurassic Madbi Formation (Hakimi et al. 2010a).

There are 28 wells drilled in North Camaal field. The average reservoir initial pressure on these wells is 1743 psi (Qishn classtic) and currently it's 1463 psi (Canadian Nexen unpublished report, 2012)

1.5.3.2 Petrophysical properties of the producing reservoirs in North Camaal:

- ***Upper Qishn****:* Qishn is a sandstone formation with an average porosity of 18%, and average effective permeability ranging from 50mD to 800mD. The average water saturation in Upper Qishn is 11%. Oil produced from Upper Qishn has an API of 32, which is light.
- ***Upper Saar****:* Upper Saar is mainly a limestone formation with some dolomite. It has an average porosity of 15%, and average effective permeability ranging from 150mD to 1000mD. The average water saturation in Upper Saar is 30%. Oil produced from Upper Saar has an API of 36, which is light.
- ***Basal Sands****:* Basal Sands are a sandstone formation. It has an average porosity of 13%, and average effective permeability of 750mD. The average water saturation in Basal Sands is 25%. Oil produced from Basal Sands has an API of 36, which is light.
- ***Basement****:* Basement rocks in North Camaal are granite. It has an average porosity of 1%, and average effective permeability is ranging from 7mD to 30mD. The average water saturation in Basal Sands is 10%. Oil produced from Basal Sands has an API of 34, which is light.

1.5.3.3 Fluid properties of the producing reservoirs in North Camaal:

- **Qishn Clastic Reservoir**

As we can see from table 1.1, the reservoir temperature is 156 F. Both the initial and bubble point pressure are 1734 psia, 47 psia respectively. Oil density is 32 API which is light oil.

Temp.	156 F
Pi, psia	1734
Pb,psia	47
Oil Density	0.865
API	32.08381503
Gas Density	0.001577

Table 1.2 Qishn S1/S2 Reservoir Fluid Properties

Table 1.2 bellow shows gas-oil-ratio, oil FVF (Formation Volume Factor), and oil viscosity against various pressure readings for both Qishn S1/S2 oils.

Pressure (psia)	Gas Oil Ratio (scf/STB)	Oil FVF (RB/STB)	Oil Viscosity (centipoise)
2015	2.82167	1.04087	3.30823
1911.42	2.82167	1.04089	3.27476
1807.84	2.82167	1.04091	3.24129
1704.26	2.82167	1.04094	3.20782
1600.68	2.82167	1.04096	3.17435
1497.11	2.82167	1.041	3.14088
1393.53	2.82167	1.04103	3.10741
1289.95	2.82167	1.04108	3.07394
1186.37	2.82167	1.04113	3.04047
1082.79	2.82167	1.04118	3.007
979.211	2.82167	1.04126	2.97353
875.632	2.82167	1.04135	2.94006
772.053	2.82167	1.04146	2.90659
668.474	2.82167	1.04161	2.87312
564.895	2.82167	1.04181	2.83965
461.316	2.82167	1.0421	2.80619
357.737	2.82167	1.04256	2.77272
254.158	2.82167	1.0434	2.73925
150.579	2.82167	1.0454	2.70578
47	2.82167	1.05627	2.67231

Table 2.3 Fluid Property Test

1.5.3.4 North Camaal Reserves:

- ***Proven reserves (1P):***

The proven reserves in North Camaal are 124.924 MMSTB (for all reservoirs), in which the recoverable is 50.994 MMSTB. According to an unpublished report from Canadian Nexen, the cumulative production until May 2012 are 47.105 MMSTB, with remaining recoverable reserves of 3.887 MMSTB to be produced.

- ***Proven, Potential, Possible reserves (3P):***

The 3P reserves in North Camaal are 135.196 MMSTB (for all reservoirs), in which the recoverable is 63.652 MMSTB. According to an unpublished report from Canadian Nexen, the cumulative production until May 2012 are 47.105 MMSTB, with remaining recoverable reserves of 16.547 MMSTB to be produced.

CHAPTER TWO

2.1 Literature review

2.1.1 Well Integration and Reservoir Properties

Well integration is the process of combining data from two or more distinct data sources so as to verify and calibrate reservoir properties and predict reservoir potential. In this research work seismic and well-log &core data are combined to ensure the success of well integration and good knowledge of the subsurface. It cannot be over-emphasized that petroleum resources are found hundreds of feet beneath the earth surface in heterogeneous formation and the precision of information on the location of these resources rely on the understanding of the geology of the formation.

Data obtained from the propagation of waves (either refraction or reflection method) can give clues on the formation characteristics. For example, seismic exploration techniques, based on the study of the propagation characteristics of elastic (seismic) waves in the earth’s crust are used to investigate the crust’s geological structure. Depending on the reflected or refracted wave signal, seismologists and geologists can predict the formation rock type at various depths from arrival time of the wave energy emitted into the formation. The wave’s arrival time is a function of the structural or crystalline arrangement of rock atomic particles. Information obtained from the propagated wave is used in predicting rock hardness, rock stress, rock density etc and in classifying rock type.

Although the resolution obtained from seismic is relatively low when compared to well logging, the area of coverage of seismic acquisition is larger than that of well-logging. Well logging on the other hand gives high resolution but tends to be limited in that it only provides information at the well location- the wellbore. Well-log data however include but not limited to porosity, permeability, lithofacies, water saturation and net pay …etc.

Tying seismic data to well data enables the prediction of geological ages, rock types, porosity, and fluid types away from the well and within the well of properties such as porosity variation, fluid types, top of abnormal pressure zones etc. from which petrophysical models can be derived.

2.1.2 Sources of Data Acquisition

The integration of data is at the core of reservoir modeling. The primary objective of integration is to explicitly account for and incorporate all data necessary for describing the reservoir and building models that approximate reality. In the petroleum industries, the principal areas from which data can be generated are:

- Seismic Survey
- Well Logs (Wire line or Logging-While-Drilling)
- Laboratory Analysis of Core
- Others

While the significance of other data sources cannot be under-rated, it is however important to state that for the purpose of this research task, emphasis would be placed on seismic survey and well log data.

2.1.2.1 Seismic Survey:

Seismic survey is one of the key geophysical approaches used in exploring for petroleum resources and by far the leading and only geophysical approach used both in exploration and development phases. Magnetic and gravity surveys, the other two geophysical approaches or methods, are used only in pre-drilling exploration.

Seismic data can be acquired both onshore and offshore with virtually the same operational principles but with devices adapted to each terrain. On land, for instance, acoustic waves are generated at or near the earth surface by shooting seismic from sources such as dynamite, thumper (a weight dropped on ground surface), dinoneis (a gas gun), or a vibroseis (which literally vibrates the earth's surface). The acoustic waves which are transmitted into the earth from dynamite and the other named sources, when reflected are received by electronic devices called geophone. Here, the geophones digitize the waves after performing a number of signal processing stages such as amplification and filtering. The processed signals are then transmitted to a nearby truck to be recorded on magnetic tape or disk. The recorded data sets are displayed in a number of forms for interpretation and research purposes; including visual display forms (photographic and dry-paper), a display of the amplitude of arriving seismic waves versus their arrival time, and a common type of display called variable-density.

By utilizing information on travel time, arrival time, seismic survey provides a way of measuring the physical properties of the subsurface formation. These measurements give geological information which is significant in identifying structures such as faults and traps as well as provide information on depth, stratigraphy and position of source rocks.

For offshore seismic survey, that is obtaining subsurface data by propagating acoustic waves over marine environment, the seismic vessel replaces the on-land truck while receiver devices called hydrophones serve the same function as the geophones which receive reflected (incoming) signals during onshore seismic survey. Performing seismic survey offshore is cheaper comparably to onshore due to the involvement of smaller workforce. Also, the offshore process is faster and simpler as most of the tasks are machine implemented.

Most of seismic survey now are 3D. 2D shooting are very little done today because of the shortcomings of 2D such as:

- Distortion of geologic structure image.
- Insufficient subsurface sampling to define small-scale geologic features (Gadallah, and Fisher, 2009).

3D seismic survey concept, firstly explained in 1980s and 1990s, its use highly expanded in searching for oil and development of oil field (Brown, 2004). In 3D

Seismic survey positioning of shots and receivers allow recorded arrivals to be assembled to represent the rayed reflected from an area of each reflecting surface (Kearey et al, 2002).

The costs of 3D seismic survey is really deserved because it eliminates the development of unnecessary wells (Sheriff and Geldart, 1983).The result of 3D seismic survey gives more accurate details and clearer image by increasing resolution of 3D seismic survey vertically and horizontally. 3D migration accuracy related to the velocity field, signal to noise ratio, migration aperture and the approach are important factors in seismic processing, the errors resulting from these factors assumed to be small, so the data will be more interpretable structurally and stratigraphically. Technology aides in processing of 3D seismic data which collected in closely spaced and producing a large amount of data. Also, in understanding of advantage of color, work with horizontal section, acoustic impedance, frequency sections, vertical seismic profile VSP and attributes (Brown, 2004).

Seismic interpretation:

seismic interpretation is the science (and art) of inferring the geology at some depth from the processed seismic record. While modern multichannel data have increased the quantity and quality of interpretable data, proper interpretation still requires that the interpreter draw upon his or her geological understanding to pick the most likely interpretation from the many "valid" interpretations that the data allow.

The seismic record contains two basic elements for the interpreter to study. The first is the time of arrival of any reflection (or refraction) from a geological surface. The actual depth to this surface is a function of the thickness and velocity of overlying rock layers. The second is the shape of the reflection, which includes how strong the signal is, what frequencies it contains, and how the frequencies are distributed over the pulse. This information can often be used to support conclusions about the lithology and fluid content of the seismic reflector being evaluated.

The interpretation process can be subdivided into three interrelated categories: structural, stratigraphic, and lithologic. 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. The aim is to develop a chronostratigraphic framework of cyclic, genetically related strata. Lithology interpretation is aimed at determining changes in pore fluid, porosity, fracture intensity, lithology, and so on from seismic data. Direct hydrocarbon indicators (DHI, HCIs, bright spots, or dim-outs) are elements employed in this lithologic interpretation process.

The process of interpreting seismic data eventually comes down to putting pencil to paper or cursor to screen. After building an exploration analog by integrating the available geological data, it is advisable to scan the dataset to observe the basin setting, major structural components, and major stratigraphic components, such as reefs, shelf breaks, and major sequence boundaries. While scanning, major faults can be picked as a guide to establishing the dominant structural style.

After scanning, detailed mapping begins by working outward from a point where geological information exists, preferably a well location with a synthetic seismogram. The horizons selected for mapping and observed fault cuts are correlated from the well to the seismic. The interpreter then begins to pick these same events away from the well on the seismic, being careful to tie at all other well locations.

Critical to the interpretation process is comparing how horizons and faults tie at line intersections. Significant effort is expended correcting misties of faults, horizons, and sequence boundaries at every line intersection. In this regard, closing the interpretation in loops around the seismic grid is a particularly effective technique. On a workstation, a quick way to check for misties is a contour map. Misties will be evident by groups of unreasonable contours. In addition, workstations can be very helpful for working out the misties among varying vintages of two-dimensional data by applying time and phase shifts automatically

Tying all lines in both 2-D and 3-D data sets is the only way to reliably construct a three-dimensional model of the subsurface using two-dimensional images. Tying around data loops is also the best way to correlate from fault block to fault block. Otherwise, faults must be jumped using reflection character, sequence analysis, or additional well control.

After all lines are picked and tied, the results of the interpretation are then summarized and presented as maps. Basically, any observation that can be made using seismic data can be posted on a base map and mapped. Maps that are routinely made include

- Time structure maps with faults
- Depth structure maps
- Seismic facies maps for reservoir, source, or seal analysis
- Seismic amplitude maps for DHI analysis
- Thickness maps inferred from seismic tuning analysis
- Fault plane maps
- Fault plane maps with cross-fault sand juxtaposition for seal analysis
- Isochron or isopach maps showing growth or thinning in a stratigraphic interval
- Seismic velocity maps for lithology determination or depth conversion

In addition, many combinations of these maps can be made, such as seismic amplitude plotted on top of structure. The only limitations in constructing these maps are the imagination and skill of the interpreter.

The overall aim of seismic interpretation is to aid in constructing the most accurate earth model or reservoir description possible. This can best be accomplished when the seismic data are merged with petrophysical, geological, and engineering databases. While the process of interpreting seismic data is basically the same on paper or in a workstation environment, the workstation offers advantages in data management, manipulation, and display and it allows for a more convenient integration of other data types.

The simplest method used for seismic interpretation started by finding interested Marker on section, there are a lot of methods to identify interested reflection, the interpreter can tie between the seismic section and an already picked section in another area, it is easy to identify reflection when interpreter be already familiar with it, this occurs with seismic data in areas he have worked overlong period in which the reflection has distinctive appearance. Another method for identification interested reflection depend on tie wells with seismic data by time-depth chart, check shot, and vertical seismic profile VSP. Synthetic seismogram one of famous method to ties formation tops in wells to seismic data. Interpreter can use stacking velocity information obtained in processing the seismic data to identify reflection; this is the seismically derived velocity, it is better to average velocities from several nearby points. The ultimate in reflection identification can be made from a vertical seismic profile or VSP, vertical seismic profile shot in surface and geophone distribution vertical in wells, information recording after rearranging obtain reflection section. Synthetic seismogram are artificial seismic traces used to establish

Correlations, the important use of synthetic seismogram is in studying the effect of changes in the layering on the seismic record. The horizon seismic picking defines as the coloring of reflections in the seismic sections that represent layers of rock, purpose of seismic picking is to obtain information about the geology in studied area, and the interpreter starts by identifying interested reflections on the section to represent rock layers. The important reflection was picking first, displaying colors maps that result after finishing picking for all seismic section to enable us for obtaining valuable subsurface geological information. The convention seismic interpretation technique usually starts by identifying horizon passed on correlation with observation formation tops in wells. The horizon that was detected on seismic sections provides us with two-dimension pictures only, but three dimensional pictures is necessary to determine geological structures style and closures.

Seismic Attribute

The Oxford Dictionary defines an attribute as, “A quality ascribed to any person or thing”, so they have extended this definition to: “Seismic Attributes are all the information obtained from seismic data, either by direct measurements or by logical or experience passed reasoning” (Taner et al., 1994).

A simple working definition a seismic attribute is any measure of seismic data that helps us better visualize or quantify features of interpretation interest, another definition response attributes characterize simple reflection boundaries and/or complex reflection zones/packets; variations within single energy envelope lobes

The seismic attributes are not seismic properties but they are the change in properties that associated with our geological target, if seismic attributes are constant (no contrast) in time slices or seismic section, they will not generate interested geological information.

Classification of seismic attributes:

There are a lot of classification of seismic attributes we must choose one that help us in the make picture of different attributes, and can make easy to choose attributes that helps our purpose, so We prefer Liner et al.’s (2004) classification into general and specific categories. Liner et al.’s general attributes are measures of geometric, kinematics, dynamic, or statistical features derived from seismic data. They include reflector amplitude, reflector time, reflector dip and azimuth, complex amplitude and edge detection/coherence, **AVO**, and spectral decomposition.These general attributes are passed on either the physical or morphological character of the data tied to lithology or geology and are therefore generally applicable from basin to basin around the world. In contrast, specific attributes have a less welldefined basis in physics or geology. While given specific attribute may be well correlated to a geologic feature or to reservoir productivity within a given basin, these correlations do not in general carry over to a different. And can add a third category to Liner et al.’s classification, that of" composite” attributes (also calumet attributes by Meldahlal et al., (2001)).

Many of the specific attributes cited in the literature are sums, products, or other combinations of more fundamental general attributes. It is preferred to use two types of composite attributes: those used to display more than one attribute at time (Chopra AND Marfurt, 2005) and those combined using geostatistics, neural nets, or other classification technology. Given the dangers of false correlations, we prefer when possible to use attributes that individually correlate to only one physical or geologic variables of interest, followed by geostatistics, neural networks.

Traditional classification of attributes

Pre-Stack attributes:

Input data are CDP (common depth point) or images gather traces. They will have directional (azimuth) and offset related information. Computations generate huge amounts of data; hence they are not practical for initial studies.

Post-Stack attributes

Stacking is an averaging process, losing offset and azimuth related information.

Input data could be CDP stacked or migrated. One should note that time migrated data will maintain their time relations, hence temporal variables, Post-stack attributes are better for observing large amounts of data in initial investigations. For detailed studies, pre-stack attributes may be incorporated.

Classifications attributes as computationally

Class I: Attributes are computed directly from traces. This data could be pre- or post-stack, 2-D or 3-D, before or after time migration. Trace envelope and its derivatives, instantaneous phase and its derivatives, bandwidth, Q, dips etc. are some of the attributes computed this way

Class II: Attributes are computed from the traces with improved S/N ratios after lateral scanning and semblance-weighted summation. Details of the computation are given in the Maximum Semblance Computation section of the Geometrical attributes. All of the Class I attributes are computed in Class II. In addition lateral continuity and dips of maximum semblance are computed from the scanning procedure.

Classification based on geology

Physical attributes

Physical attributes relate to physical qualities and quantities. The magnitude of the trace envelope is proportional to the acoustic impedance contrast, frequencies relate to the bed thickness, wave scattering and absorption. Instantaneous and average velocities directly relate to rock properties. Consequently, these attributes are mostly used for lithological classification and reservoir characterization.

Geometrical attributes

Geometrical attributes describe the spatial and temporal relationship of all other attributes. Lateral continuity measured by semblance is a good indicator of bedding similarity as well as discontinuity. Bedding dips and curvatures give depositional information.

Geometrical attributes were initially thought to help the stratigraphic interpretation.

However, further experience has shown that the geometrical attributes defining the event characteristics and their spatial relations, quantify features that directly help in the recognition of depositional patterns, and related lithology.

Applications of seismic attributes

General applications

- To intelligently extrapolate sparse well measurements of reservoir thickness, porosity, and hydrocarbon saturation onto the much denser seismic grid. The first use of attributes is to intelligently extrapolate well measurements of reservoir thickness, porosity, and hydrocarbon saturation onto the much denser seismic grid. Prediction tools include multivariable statistics, geostatistics, and neural networks applied to attributes that are sensitive to amplitude and thickness. Practitioners typically are Petro physicists, geophysicists, and engineers
- To reconstruct the tectonic, depositional, and diagenetic history, allowing us to infer lithology, porosity, seal, fracture density and fracture orientation
- To communicate your play in a limited time to non-geoscientists: The third use of attributes is to communicate complex geology to others in a short amount of time. Attributes do not 'create' any new information. But extracting that information takes time and skill. Attributes are particularly useful in quickly describing key tectonic and depositional processes to non-geoscientists – bankers, engineers, and landmen, management, and government regulators.

Important geological applications for seismic attributes

- Reflector divergence and/or parallelism.
- Angular unconformities.
- Stratigraphic terminations.
- Reflector curvature.
- Flexures and folds.
- Unresolved or poorly migrated faults.
- Differential compaction.

Supervised training neural networks

There have been a number of Neural Networks developed within the last couple of decades. Supervised trainable networks are used in many different fields. In this case, the user provides some examples for the neural network to learn, and then the network is tested with another data set to check the success of training. One important point to remember is that the network, if trained properly, will recognize and correctly classify only those cases included in the training set. Any new conditions not included in the training set will be misclassified or not recognized. Feed forward, fully connected perceptron artificial neural networks (**ANN**), Learning Vector Quantization (**LVQ**), Probabilistic Neural Networks (**PNN**), and Radial Basis Function Networks (RBF) are some of the available networks. Each of the methods has its advantages and limitations.

Seismic Generic inversion:

It is an approach to inversion and estimating rock property, it's a combination from neural network and genetic algorithm. This method characterize by its fast user friendly and cost effective (Veeken et al, 2009). This approach is patterned by Schlumberger and incorporated into from Petrel 2009.1 and later versions. Only seismic data post stack and well logs recorded in control wells needed. Horizon interpretation, fault interpretation, and wavelet extraction are not needed which is different than model based inversion (Veeken et al, 2009).

2.1.2.2 Well Logs:

To conduct formation evaluation which is also linked to the analysis of the subsurface, wide range of measurements and geophysical techniques are required. Information gathered through the use of calibrated instruments enables the determination of the reservoir's extent, pay thickness, porosity, rock type, storage capacity, hydrocarbon content, and well producibility. Contingent on these parameters is also the determination of the economic value and production potential of the reservoir.

Well logging provides an excellent medium for the determination of the reservoir parameters. Well logging is the use of down-hole instrument, either during or after drilling, to evaluate the formation and measure reservoir parameters. Log measurements, when properly calibrated, can give the majority of the petrophysical parameters. Specifically, logs can provide a direct measurement or give a good indication of:

- Porosity, both primary and secondary
- Permeability
- Water saturation and hydrocarbon movability
- Hydrocarbon type (oil, gas, or condensate)
- Lithology
- Formation dip and structure
- Sedimentary environment

A single well log cannot exclusively extract all relevant data from a reservoir. Data obtained from well logs fitted for specific activities are assimilated and utilized for the evaluation of the reservoir. The table below indicates some of the most encountered well logging tools and data each may be capable of extracting from a well:

No.	Well Logging Tool	Data
1	Sonic Log	Interval Transit Time
2	Density Log	Bulk Density
3	Porosity Log	Total Porosity
4	Gamma Ray Log	Shale Volume
5	Resistivity Log	Formation True Resistivity

Table 2.1: Well Logging Tools and Associated Data

Logging can answer many questions on topics ranging from basic geology to economics; however, logging by itself cannot answer all the formation evaluation problems. Coring, core analysis, and formation testing are all integral parts of any formation evaluation effort.

2.1.2.3 Laboratory Analysis of Core:

A core is a cylindrical sample of the formation extracted from a depth of interest for laboratory analysis. Cores are cut where specific lithologic and rock parameter data are required. It is usually sampled and analyzed to determine static and dynamic reservoir properties. Static properties are reservoir properties with no relation to flow while reservoir properties in consideration to flow parameters are dynamic properties. Ranging from few inches to a couple of feet in length, two essential reservoir properties that can be extracted from core are permeability and porosity. Laboratory techniques used to analyze cores are:

- Bean Stark Method
- Archimedes Method
- Charles and Boyles' Law Methods

2.1.2.4 Others:

Additional sources of information that can be used for modeling reservoir are as indicated below:

- Sequence stratigraphic interpretation/layering – gives information on definition of the continuity and trends within each layer of the reservoir
- Trends and stacking Pattern-available from a regional geological interpretation
- Analog data from outcrop or densely drilled similar field (size distributions, measure of lateral continuity)
- Well test and production data –gives information on the following interpreted data (permeability, thickness, skin, flow efficiency, channel widths, barriers, flow paths)

2.1.2 Overview of Petrophysical Properties

Tiab and Donaldson (2004) defined petrophysics as "the study of rock properties and their interactions with fluids (gases, liquid hydrocarbons, and aqueous solutions)."In petroleum studies, petrophysical properties are those properties of the reservoir which enable the reservoir rocks to store and transmit reservoir fluids thus also enabling quantitative determination of the in situ hydrocarbon as well as the appropriate method of extraction of the fluids".

For the purpose of this research work, the key petrophysical properties of interest are:

- Water Saturation
- Porosity
- Permeability
- Volume of shale
- Net-to-Gross Ratio (Net-to-Gross Sand Distribution)

2.1.3 Basic definition of key petrophysical properties Porosity:

Is the fraction of the bulk volume of a material (rock) that is occupied by pores (voids). Denoted ϕ, porosity can also be defined as the ratio of the volume of void spaces in a rock to the total volume of the rock. Porosity is expressed in decimal or percentage and can represent the total volume of a rock occupied by empty space. It can be filled with hydrocarbons, moveable water, capillary water or clay bound water (Cluff and Cluff, 2004; Hook, 2003; Rider and Kennedy, 2011; Shepherd, 2009). In this study, the porosity estimation is based on two well logs (Neutron, and Density log).

$$\varphi = \frac{V_P}{V_b} \quad \dots \dots \dots \dots \dots \dots \dots \dots \; Eq. 2.1$$

Total Porosity

The total porosity can be defined as the total void space including isolated pores and the space occupied by clay- bound water. In equation 2.2 the bulk density of sample, bulk density and the density fluid that the sample is saturated with correspond to the porosity that is defined as the total porosity. The theoretical values for bulk density and fluid density for sedimentary rock ranges from 2.65 g/cc to 2.96 g/cc and from 1.00 g/cc to 1.4 g/cc, respectively. The porosity can be measured by core analysis or by log measurements including density and neutron porosity.

$$\varphi = \frac{\rho b - \rho ma}{\rho f - \rho ma} \quad \dots \dots \dots \dots \dots \dots \dots \dots \; Eq. 2.2$$

Neutron porosity:

Neutron log is used to measure the porosity in the formation. In most cases like in limestone lithology, it can be read directly from the neutron log. For the other lithology, it should be used by taking the average of porosity calculates from density and neutron logs to get rid of the lithologic effects (Glover, 2005; Rider and Kennedy, 2011). Glover, (2005) explain further that in gas saturation lithology neutron log gives lower values for porosity, which can be corrected.

Density Porosity:

Density log is useful to discriminate lithology as well as to calculate the porosity and hydrocarbon density. The general scale of measurement is from 1.95 to 2.95, with units of g/cm3 (Rider and Kennedy, 2011). The general equation to measure the porosity expresed by (Rider and Kennedy, 2011)

$$\Phi = (\rho_{ma} - \rho_b) / (\rho_{ma} - \rho_f) \text{ … … …} \textbf{Eq. 2.3}$$

ρ_{ma} = Density of the matrix material

ρ_f = Pore fluid density

ρ_b = General density log reading

Densities of common lithologies and fluids are shown in the Tables in the figure below:

Common values of matrix density and photoelectric in rocks

Rock	*Matrix Density*	*Pe*
Sandstone	2.65	1.8 - 2.5
Siltstone	2.65	2.5 - 3.5
Shale	2.20 – 2.60	3.5 - 4.5
Limestone	2.71	> 5
Dolomite	2.85	3.5 - 5
Anhydrite	2.96	> 5

Common values of matrix density for fluids

Filtrate (Fluids)	Density (g/cc)
Fresh water Salt water (120,000)	1 1.1
Oil (med. Gravity)	0.8
Gas (160F,5000psia)	0.2

Figure 24.1 value of matrix density, which are used during porosity calculation.

The value of matrix density, which are used during porosity calculation varied with respect to the volumetric percentage of shales presence in the formation.

Average porosity from Neutron and Density logs:

The average N-D porosily is the exact porosity. The porosity estimated from the equation is used in this study to avoid uncertanities to interpret the data

$$\emptyset_{Avg} = \sqrt{\frac{\emptyset^2_{density}+\emptyset^2_{neutron}}{2}} \quad \textbf{... ... ...Eq. 2.4}$$

Effective porosity:

In shale dominated sandstone most of the porosity is occupied by the clay bound water or small clay particles, which may not producible and have no economic interim of the petroleum industry. To avoid these kind of uncertainties, effective porosity is used instead of total porosity, while calculating and marking the pay zones intervals from reservoir intervals (Cluff and Cluff, 2004; Rider and Kennedy, 2011). To calculate the effective porosity the following Equation is used

Effective porosity = Porosity x (1-Vsh) ***... ... ... Eq. 2.5***

Lithology Discrimination:

The gamma ray and density logs are very useful to discriminate lithology. On the basis of gamma ray log sandstones, shales and carbonates sequences can be marked (Soto et al., 2010). For this study gamma ray readings are used to define different lithologies. Furthermore, to distinguish sandstone and carbonate the density log is used parallel with the gamma ray log.

Volume of Shale:

This is the space occupied by shale or the fraction of shale (clay), present in reservoir rock. The Volume of Shale is determined from mathematical correlations and gamma ray index. In mathematical equations, the volume of shale is represented Vsh.

$$V\ Shale = \frac{GRlog - GRClean}{GRshale - GRclean} \quad \textbf{... ... ...Eq. 2.6}$$

Tiab and Donaldson (2004) identified the three common modes of shale distribution within a reservoir rock -sand, carbonates. They classified the shale types as laminar, dispersed and structural and noted their effect on reservoir properties. Description of the shale types are as outlined below:

- ***Laminar shale*** – This refers to thin beds of shale deposited between layers of clean sands. By definition, the sand and shale laminae do not exceed 0.5 in. thickness. The effect of this type of shale on porosity and permeability of the formation is generally assumed to be negligible.
- ***Dispersed clays*** – These are clays which evolved from the in-situ alteration and precipitation of various clay minerals. They may adhere and coat sand grains or they may partially fill the pore spaces. This mode of clay distribution considerably reduces permeability and porosity of the formation, while increasing water saturation. This increase in water saturation is due to the fact that clays adsorb more water than quartz (sand).
- ***Structural shale*** – exists as grain of clay forming part of the solid matrix along with sand grains. This type of clay distribution is a rare occurrence. They are considered to have properties similar to those of laminar shale, as they are both of depositional origin. They have been subjected to the same overburden pressure as the adjacent thick shale bodies and. thus are considered to have the same water content.

2.1.3.4 Water Saturation:

Water saturation is the relative extent to which the pores in rocks are filled with water. Saturation is expressed as the fraction, or percent, of the total pore volume occupied by the oil, gas, or water. Water saturation is denoted Sw and is expresses in percent or fraction.

Water saturation is calculated by using the Indonesian Equation in Schlumberger Techlog Petrophysic software. Porosity is used from the Eq. 2.6, which calculate average porosity. Cement value (m) is taken as 1.5; tortuosity factor (n) is taken as 2. Deep resistivity values are used from Rt. On the basis of water saturation, pay zone is separated from reservoir intervals. The Rw values are estimated by using the Pickeet plot.

The Indonesian Equation

The Indonesian equation is a complex formula, but at the same time a good option to use in the determination the water saturation when the formation is influenced by clay. It is also referred to as the effective water saturation due to its dependency on log data. No special core analysis data are needed in this calculation and due to this it is very applicable for the first drilled wells in a area where there is not possible to obtain SCAL data. The method of determining the water saturation by Indonesia can be divided into two main groups; either treating the shale as a volume of conductive material or analyzing the effects of clay counter ions. In the interpretation performed in this thesis the version of the Indonesia Equation where the shale is treated as a volume has been used. The Indonesia equation is very applicable in calculations where the shale content is higher than 30% and the ratio of shale resistivity to formation water resistivity is lower than 10%.

The Indonesia equation is given below:

$$\frac{1}{\sqrt{R_T}} = \left[\frac{V_{cl}^{\,1-\frac{V_{cl}}{2}}}{\sqrt{R_{cl}}} + \frac{\phi^{\frac{m}{2}}}{\sqrt{a * R_w}}\right] * S_w^{\frac{n}{2}}$$ **… … …Eq. 2.7**

where

Rt: True formation resistivity

Vcl: Clay volume

Rcl: Clay resistivity

Rw: Water resistivity

a: Tortuosity factor

m: Cementation factor

ϕ: Porosity

n: Saturation exponent

Sw: Water saturation

2.1.3.5 Permeability:

In fluid flow, characterizes the ease with which fluids flow through a porous medium. Theoretically, permeability is the intrinsic property of a porous medium, independent of the fluids involved. Permeability is denoted K and expressed in unit of md. In short, permeability is the measure of the ease with which a fluid flows through a rock.

2.1.3.6 Net-to-Gross Ratio and pay zone

Net-to-gross (NTG) is the fraction of reservoir volume occupied by hydrocarbon-bearing rocks. It is a global attribute and as such no replicate of it can be found over the reservoir. An estimate of global NTG is obtained from wells, but this estimate depends heavily on the location of the few wells available.

The net-to-gross ratio reduces the maximum reservoir thickness to the anticipated pay (permeable reservoir) thickness. Net-to-Gross Sand is reservoir thickness less shale thickness. This is a factor used to identify probable producing regions of a formation.

Gross interval is a total thickness of the reservoir formation. It includes all zones (productive zone, non-productive zone, tight zone, shaly or silty zone), no cutoff has applied. Net reservoir interval contains the rock of good reservoir quality sorted by Vsh and porosity cutoff. Net reservoir interval also contained the fully water saturated and hydrocarbon saturated zones. Pay zone interval contained the commercially producible hydrocarbon. Pay zone interval obtained by putting the cut off values of water saturation as well. Pay zone also eliminate depth below the Oil-Water-Contact (OWC), which is fully water saturated (Cluff and Cluff, 2004; Dean, 2007; Egbele et al., 2005; Gaffney, 2010; Li et al., 1997; Shepherd, 2009).

On the basis of the effective porosity, Vsh and water saturation, reservoir intervals and net pay zones are marked from the gross formation intervals. In this study for defining the reservoir interval, the effective porosity is greater than 10% and volume of shale less than 50% are used. For net pay or producible zones marking, water saturation less than 50%.

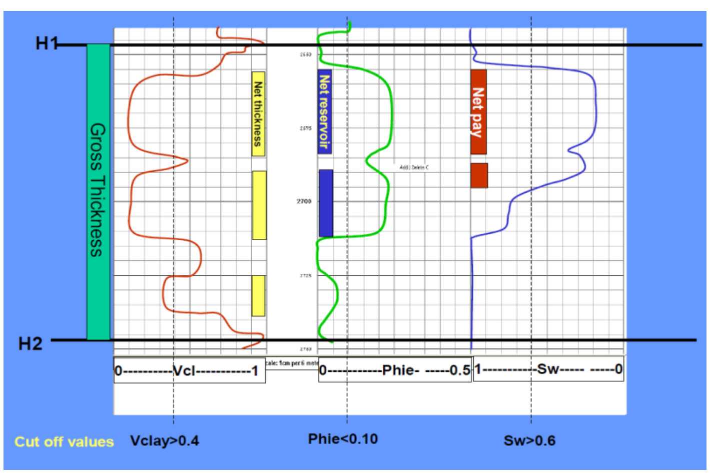


Figure 2.2 Vsh and porosity cutoff

The determination of net pay is a required input to calculate the hydrocarbon pore feet, F_{HCP}, at a wellbore and its input to the overall reservoir original oil in place (OOIP) or original gas in place (OGIP) calculations. The total F_{HCP} at a well is the point-by-point summation over the reservoir interval with Eq. 7. The top and base of the reservoir interval are defined by geologists on the basis of core descriptions and log characteristics.

$$F_{HCP} = \sum_{i=1}^{i=m} h_{ni} \phi_i \left(1 - S_w\right)_i \quad \text{... ... ... Eq. 2.8}$$

In the F_{HCP} calculation, net pay, hni, at each data point has a value of either 1 (pay) or 0 (nonpay). The "net-to-gross ratio" or "net/gross" (N/G) is the total amount of pay footage divided by the total thickness of the reservoir interval (for simplicity, the well is assumed here to be vertical). A N/G of 1.0 means that the whole of the reservoir interval is pay footage. In this formula, any foot (or half foot) that is defined as nonpay contributes absolutely nothing to the subsequent reservoir-engineering OOIP (or OGIP) and reserves calculations, even if it contains some amount of hydrocarbons. The net-pay determination should be performed in a reasonable practical manner, but it should be recognized that when any cutoff is used, the result will, to some extent, be arbitrary.

2.1.4 Acquisition of Petro physical Data from Well Logs

Devices designed to record or measure subsurface properties in the wellbore are generally referred to as well logs. Although there are many different well logs, few will be discussed below~~.~~

2.1.4.1 Resistivity Log

Resistivity logs measure the ability of rocks to conduct electrical current and are scaled in units of ohm-meters. There is a wide variety of resistivity tool designs, but a major difference between them lies in their "depth of investigation" (how far does the measurement extend beyond the borehole wall?) and their "vertical resolution" (what is the thinnest bed that can be seen?). These characteristics become important because of the process of formation "invasion" that occurs at the time of drilling.

2.1.4.2 Density Logs

The density logs record a formation's bulk density. This is essentially the overall density of a rock including solid matrix and the fluid enclosed in the pores. The log is scaled linearly in bulk density (g/cm3) and includes a correction curve that indicates the degree of compensation applied to the bulk density data. Density logging is based on the physical phenomenon of gamma ray scattering as a function of the bulk density of an environment irradiated by a gamma ray source. Density logs are primarily used as porosity logs.

2.1.4.3 Sonic Logs

The sonic log is a device that measures the time it takes sound pulses to travel through the formation. This time is referred to as the interval transit time, or slowness and it is the reciprocal of velocity of the sound wave. The interval transit time of a given formation is dependent on the lithology and porosity. Therefore, a formation's matrix velocity must be known to derive sonic porosity either by chart or by using formula.

Wyllie's equation can be used to calculating the matrix porosity of consolidated sandstone and carbonate formations respectively. The applicability of the formula holds for sandstone with inter-granular porosity or carbonate with inter-crystalline porosity. The formula incorporates an adjustment factor, designated empirical compaction factor (Cp).

2.1.4.4 Neutron Logs

Neutron logs are used principally for delineating porous formations and determination of porosity. Neutron logs measure the hydrogen ion concentration in a formation. Therefore, in clean formations, whose pores are filled with water or oil, neutron logs respond to the amount of liquid-filled porosity.

In neutron logging there are three processes of interest: neutron emission, neutron scattering and neutron absorption. Neutrons are created from a chemical source in the neutron logging tool, which continually emits neutrons. These neutrons collide with the nuclei of the formation material, and result in a neutron losing some of its energy. Because the hydrogen atom is almost equal in mass to the neutron, maximum energy loss occurs when the neutron collides with a hydrogen atom. Also, because hydrogen in a porous formation is concentrated in the fluid-filled pores, energy loss can be related to the formation's porosity. Neutron logs responses vary, depending on:

- Differences in detector types
- Spacing between source and detector
- Lithology – i.e., sandstone, limestone, and dolomite.

These variations can be compensated for by using the appropriate charts. It is important to note that unlike all other logs, neutron logs must be interpreted from the specific chart designed for a specific log. This is so because, unlike other logs that calibrated in basic physical units, neutron logs are not.

2.1.4.5 Gamma Ray Log

The Gamma Ray logging is a continuous measurement of the natural radioactivity emanating from the formations. Principal isotopes emitting radiation are Potassium-40, Uranium, and Thorium (K40, U, Th). Isotopes concentrated in clays; thus emit higher radioactivity in shales than other formations. Sensitive detectors count the number of gamma rays per unit of time. Gamma Ray logs are recorded in "API Units" which is 1/200th of the calibrated, standard response.

From the gamma ray log the following information about the formation can be generated:

- Estimate bed boundaries,
- Stratigraphic correlations
- Estimate shale content
- Perforating depth control
- Identify mineral deposits of potash, uranium, and coal
- Monitor movement of injected radioactive material

2.1.4.6 Spontaneous Potential Log

The spontaneous potential log is a well-logging device that measures the difference in the natural electrical potentials that occur in boreholes and generally distinguishes porous, permeable sandstones from intervening shales. The natural driving force or "natural battery" is caused when the use of drilling mud with a different salinity from the formation waters, causes two solutions to be in contact that have different ion concentrations. Ions diffuse from the more concentrated solution (typically formation water) to the more dilute.

2.2 Reservoir Engineering:

2.2.1 Properties of Crude Oil Systems

Petroleum (an equivalent term is crude oil) is a complex mixture consisting predominantly of hydrocarbons and containing sulfur, nitrogen, oxygen, and helium as minor constituents. The physical and chemical properties of crude oils vary considerably and are dependent on the concentration of the various types of hydrocarbons and minor constituents present.

An accurate description of physical properties of crude oils is of a considerable importance in the fields of both applied and theoretical science and especially in the solution of petroleum reservoir engineering problems. Physical

properties of primary interest in petroleum engineering studies include:

- Fluid gravity
- Specific gravity of the solution gas
- Gas solubility
- Bubble-point pressure
- Oil formation volume factor
- Isothermal compressibility coefficient of undersaturated crude oils
- Oil density
- Total formation volume factor
- Crude oil viscosity
- Surface tension

Data on most of these fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids. In the absence of

experimentally measured properties of crude oils, it is necessary for the petroleum engineer to determine the properties from empirically derived correlations.

Crude Oil Gravity

The crude oil density is defined as the mass of a unit volume of the crude at a specified pressure and temperature. It is usually expressed in pounds per cubic foot. The specific gravity of a crude oil is defined as the ratio of the density of the oil to that of water. Both densities are measured at 60°F and atmospheric pressure:

$$\gamma_o = \frac{\rho_o}{\rho_w}$$ **… … ... Eq. 2.9**

where

γo = specific gravity of the oil

ρo = density of the crude oil, lb/ft3

ρw = density of the water, lb/ft3

Although the density and specific gravity are used extensively in the petroleum industry, the API gravity is the preferred gravity scale. This gravity scale is precisely related to the specific gravity by the following expression:

$$^{\circ}API = \frac{141.5}{\gamma_o} - 131.5$$ **… … ... Eq. 2.10**

The API gravities of crude oils usually range from 47° API for the lighter crude oils to 10° API for the heavier asphaltic crude oils.

Specific Gravity of the Solution Gas

The specific gravity of the solution gas γg is described by the weighted average of the specific gravities of the separated gas from each separator. This weighted average approach is based on the separator gas-oil ratio, or:

$$\gamma_g = \frac{\sum_{i=1}^{n} (R_{sep})_i \left(\gamma_{sep}\right)_i + R_{st}\gamma_{st}}{\sum_{i=1}^{n} (R_{sep})_i + R_{st}}$$ **… … ... Eq. 2.11**

Where: n = number of separators

Rsep = separator gas-oil ratio, scf/STB

γsep = separator gas gravity

Rst = gas-oil ratio from the stock tank, scf/ STB

γst = gas gravity from the stock tank

Gas Solubility

The gas solubility Rs is defined as the number of standard cubic feet of gas that will dissolve in one stock-tank barrel of crude oil at certain pressure and temperature. The solubility of a natural gas in a crude oil is a strong function of the pressure, temperature, API gravity, and gas gravity.

For a particular gas and crude oil to exist at a constant temperature, the solubility increases with pressure until the saturation pressure is reached. At the saturation pressure (bubble-point pressure) all the available gases are dissolved in the oil and the gas solubility reaches its maximum value. Rather than measuring the amount of gas that will dissolve in a given stock-tank crude oil as the pressure is increased, it is customary to determine the amount of gas that will come out of a sample of reservoir crude oil as pressure decreases.

A typical gas solubility curve, as a function of pressure for an undersaturated crude oil, is shown in Figure 2.3. As the pressure is reduced from the initial reservoir pressure pi, to the bubble-point pressure pi, no gas evolves from the oil and consequently the gas solubility remains constant at its maximum value of Rsb. Below the bubble-point pressure, the solution gas is liberated and the value of R s decreases with pressure. The following five empirical correlations for estimating the gas solubility are given below:

- Standing's correlation
- The Vasquez-Beggs correlation
- Glaso's correlation
- Marhoun's correlation
- The Petrosky-Farshad correlation

Bubble-Point Pressure

The bubble-point pressure pb of a hydrocarbon system is defined as the highest pressure at which a bubble of gas is first liberated from the oil. This important property can be measured experimentally for a crude oil system by conducting a constant-composition expansion test.

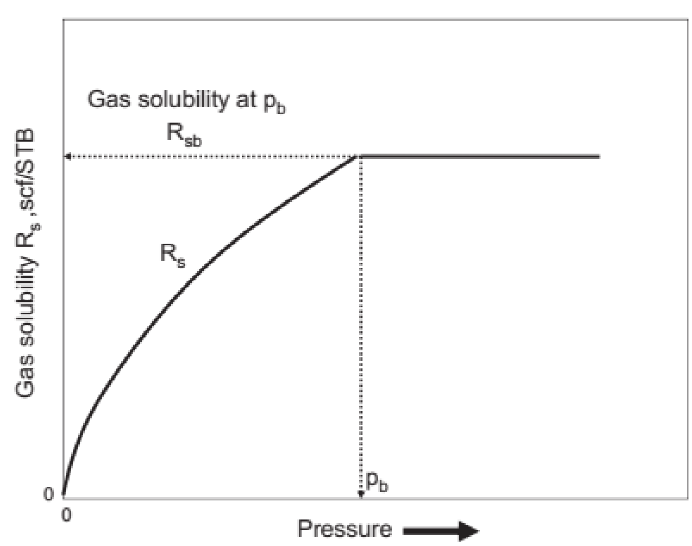


Figure 2.3 Gas-Solubility as a function of pressure relationship

In the absence of the experimentally measured bubble-point pressure, it is necessary for the engineer to make an estimate of this crude oil property from the readily available measured producing parameters. Several graphical and mathematical correlations for determining pb have been proposed during the last four decades. These correlations are essentially based on the assumption that the bubble-point pressure is a strong function of gas solubility Rs, gas gravity γg, oil gravity API, and temperature T, or:

$$p_b = f\left(R_s, \gamma_g, \text{API}, T\right)$$ **… … ... Eq. 2.12**

Oil Formation Volume Factor

The oil formation volume factor, Bo, is defined as the ratio of the volume of oil (plus the gas in solution) at the prevailing reservoir temperature and pressure to the volume of oil at standard conditions. B o is always greater than or equal to unity. The oil formation volume factor can be expressed mathematically as:

$$B_o = \frac{(V_o)_{p,T}}{(V_o)_{sc}}$$ **… … ... Eq. 2.13**

Where:

Bo = oil formation volume factor, bbl/STB

(Vo)p,T = volume of oil under reservoir pressure p and temperature T, bbl

(Vo)sc = volume of oil is measured under standard conditions, STB

A typical oil formation factor curve, as a function of pressurefor an undersaturated crude oil (pi > pb), is shown in Figure 2.4. As the pressure is reduced below the initial reservoir pressure pi, the oil volume increases due to the oil expansion. This behavior results in an increase in the oil formation volume factor and will continue until the bubble–point pressure is reached. At pb, the oil reaches its maximum expansion and consequently attains a maximum value of Bob for the oil formation volume factor. As the pressure is reduced below pb, volume of the oil and Bo are decreased as the solution gas is liberated. When the pressure is reduced to atmospheric pressure and the temperature to 60°F, the value of Bo is equal to one.

Most of the published empirical Bo correlations utilize the following generalized relationship:

$$B_o = f\left(R_s, \gamma_g, \gamma_o, T\right) \quad \text{… … … Eq. 2.14}$$

Isothermal Compressibility Coefficient of Crude Oil "co"

Isothermal compressibility coefficients are required in solving many reservoir engineering problems, including transient fluid flow problems, and they are also required in the determination of the physical properties of the undersaturated crude oil.

By definition, the isothermal compressibility of a substance is defined mathematically by the following expression:

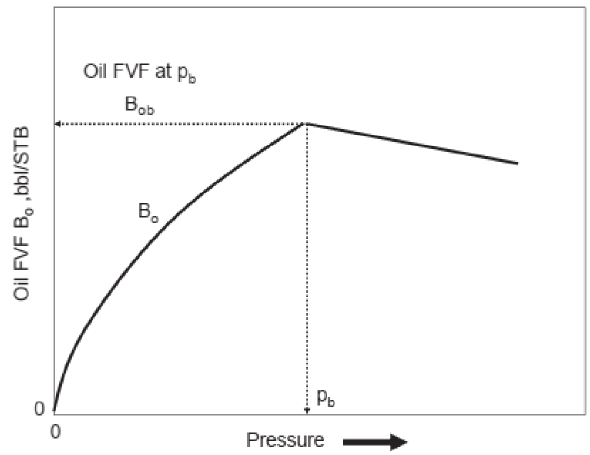


Figure 2.4 Oil Formation Volume Factor "FVF" as a function of pressure relationship.

$$c = -\frac{1}{V}\left(\frac{\partial V}{\partial p}\right)_T \quad \text{… … … Eq. 2.15}$$

Crude Oil Density

The crude oil density is defined as the mass of a unit volume of the crude at a specified pressure and temperature. It is usually expressed in pounds per cubic foot. Several empirical correlations for calculating the density of liquids of unknown compositional analysis have been proposed. The correlations employ limited PVT data such as gas gravity, oil gravity, and gas solubility as correlating parameters to estimate liquid density at the prevailing reservoir pressure and temperature.

To calculate the density of the oil at pressure below or equal to the bubble–point pressure we can use the equation below:

$$\rho_o = \frac{62.4\gamma_o + 0.0136 R_s \gamma_g}{B_o} \quad \text{… … … Eq. 2.16}$$

Where:

γo = specific gravity of the stock–tank oil

Rs = gas solubility, scf/STB

ρo = oil density, lb/ft

Total Formation Volume Factor

To describe the pressure-volume relationship of hydrocarbon systems below their bubble-point pressure, it is convenient to express this relationship in terms of the total formation volume factor as a function of pressure. This property defines the total volume of a system regardless of the number of phases present. The total formation volume factor, denoted Bt, is defined as the ratio of the total volume of the hydrocarbon mixture (i.e., oil and gas, if present), at the prevailing pressure and temperature per unit volume of the stock-tank oil. Because naturally occurring hydrocarbon systems usually exist in either one or two phases, the term “two-phase formation volume factor” has become synonymous with the total formation volume.

Mathematically, Bt is defined by the following relationship:

$$B_t = \frac{(V_o)_{p,T} + (V_g)_{p,T}}{(V_o)_{sc}}$$ **… … ... Eq. 2.17**

Where:

Bt = total formation volume factor, bbl/STB

(Vo)p, T = volume of the oil at p and T, bbl

(Vg)p, T = volume of the liberated gas at p and T, bbl

(Vo)sc = volume of the oil at standard conditions, STB

Crude Oil Viscosity

Crude oil viscosity is an important physical property that controls and influences the flow of oil through porous media and pipes. The viscosity, in general, is defined as the internal resistance of the fluid to flow.

The oil viscosity is a strong function of the temperature, pressure, oil gravity, gas gravity, and gas solubility. Whenever possible, oil viscosity should be determined by laboratory measurements at reservoir temperature and pressure. The viscosity is usually reported in standard PVT analyses. If such laboratory data are not available, engineers may refer to published correlations, which usually vary in complexity and accuracy depending upon the available data on the crude oil.

According to the pressure, the viscosity of crude oils can be classified into three categories:

- *Dead-Oil Viscosity*

  The dead–oil viscosity is defined as the viscosity of crude oil at atmospheric pressure (no gas in solution) and system temperature.

- *Saturated-Oil Viscosity*

  The saturated (bubble-point)-oil viscosity is defined as the viscosity of the crude oil at the bubble–point pressure and reservoir temperature.

- *Undersaturated-Oil Viscosity*

  The undersaturated-oil viscosity is defined as the viscosity of the crude oil at a pressure above the bubble-point and reservoir temperature.

Surface/Interfacial Tension

The surface tension is defined as the force exerted on the boundary layer between a liquid phase and a vapor phase per unit length. This force is caused by differences between the molecular forces in the vapor phase and those in the liquid phase, and also by the imbalance of these forces at the interface. The surface can be measured in the laboratory and is unusually expressed in dynes per centimeter. The surface tension is an important property in reservoir engineering calculations and designing enhanced oil recovery projects.

Sugden (1924) suggested a relationship that correlates the surface tension of a pure liquid in equilibrium with its own vapor. The correlating parameters of the proposed relationship are molecular weight M of the pure component, the densities of both phases, and a newly introduced temperature independent parameter Pch. The relationship is expressed mathematically in the following form:

$$\sigma = \left[\frac{P_{ch}(\rho_L - \rho_v)}{M}\right]^4 \quad \textbf{… … ... Eq. 2.18}$$

where σ is the surface tension and Pch is a temperature independent parameter and is called the parachor.

2.2.2 Laboratory Analysis of Reservoir Fluids

Accurate laboratory studies of PVT and phase-equilibria behavior of reservoir fluids are necessary for characterizing these fluids and evaluating their volumetric performance at various pressure levels. There are many laboratory analyses that can be made on a reservoir fluid sample. The amount of data desired determines the number of tests performed in the laboratory. In general, there are three types of laboratory tests used to measure hydrocarbon reservoir samples:

Primary tests

These are simple, routine field (on-site) tests involving the measurements of the specific gravity and the gas-oil ratio of the produced hydrocarbon fluids.

Routine laboratory tests

These are several laboratory tests that are routinely conducted to characterize the reservoir hydrocarbon fluid. They include:

- Compositional analysis of the system
- Constant-composition expansion
- Differential liberation
- Separator tests
- Constant-volume depletion

Special laboratory

PVT tests These types of tests are performed for very specific applications. If a reservoir is to be depleted under miscible gas injection or a gas cycling scheme, the following tests may be performed:

- Slim-tube test
- Swelling test

2.2.3 Primary Recovery Mechanisms

For a proper understanding of reservoir behavior and predicting future performance, it is necessary to have knowledge of the driving mechanisms that control the behavior of fluids within reservoirs. The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the wellbore. There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

- Rock and liquid expansion drive
- Depletion drive
- Gas cap drive
- Water drive
- Gravity drainage drive
- Combination drive

These driving mechanisms are discussed as follows.

Rock and Liquid Expansion

When an oil reservoir initially exists at a pressure higher than its bubble-point pressure, the reservoir is called an undersaturated oil reservoir. At pressures above the bubble-point pressure, crude oil, connate water, and rock are the only materials present. As the reservoir pressure declines, the rock and fluids expand due to their individual compressibilities. The reservoir rock compressibility is the result of two factors:

- Expansion of the individual rock grains
- Formation compaction

Both of the above two factors are the results of a decrease of fluid pressure within the pore spaces, and both tend to reduce the pore volume through the reduction of the porosity.

As the expansion of the fluids and reduction in the pore volume occur with decreasing reservoir pressure, the crude oil and water will be forced out of the pore space to the wellbore. Because liquids and rocks are only slightly compressible, the reservoir will experience a rapid pressure decline. The oil reservoir under this driving mechanism is characterized by a constant gas-oil ratio that is equal to the gas solubility at the bubble point pressure.

In the case of a volumetric reservoir with a heavy oil that is characterized by both; a low gas solubility and a low bubble point pressure, the reservoir driving mechanism for this type of reservoirs is considered the least efficient driving force and usually results in the recovery of only a small percentage of the total oil in place ranging between 3-5%. Figure 2.5 shows a conceptual illustration of the impact of the low gas solubility on the reservoir recovery performance.

The Depletion Drive Mechanism

This driving form may also be referred to by the following various terms:

- Solution gas drive
- Dissolved gas drive
- Internal gas drive

In this type of reservoir, the principal

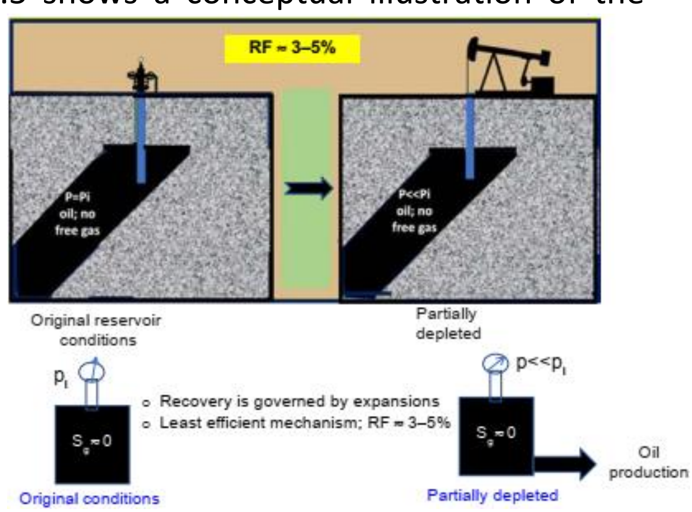


Figure 2.5 Oil reservoir under rock and fluid expansions driving mechanism.

source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble-point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space as shown conceptually in Figure 2.6.

Cole (1969) suggests that a depletion-drive reservoir can be identified by the following characteristics:

Reservoir pressure: The reservoir pressure declines rapidly and continuously. This reservoir pressure behavior is attributed to the fact that no extraneous fluids or gas caps are available to provide a replacement of the gas and oil withdrawals.

Water production: The absence of a water drive means there will be little or no water production with the oil during the entire producing life of the reservoir.

Gas-oil ratio: A depletion-drive reservoir is characterized by a rapidly increasing gas-oil ratio from all wells, regardless of their structural position. After the reservoir pressure has been reduced below the bubble-point pressure, gas evolves from solution throughout the reservoir. Once the gas saturation exceeds the critical gas saturation, free gas begins to flow toward the wellbore and gas-oil ratio increases. The gas will also begin a vertical movement due to the gravitational forces, which may result in the formation of a secondary gas cap. Vertical permeability is an important factor in the formation of a secondary gas cap.

Ultimate Oil Recovery: Oil production by depletion drive is usually the least efficient recovery method. This is a direct result of the formation of gas saturation throughout the reservoir. Ultimate oil recovery from depletion-drive reservoirs may vary from between 20% and 35% based on the crude oil gas-solubility. The low recovery from this type of reservoirs suggests that large quantities of oil remain in the reservoir and, therefore, depletion-drive reservoirs are considered the best candidates for secondary recovery applications.

Gas Cap Drive

Gas-cap-drive reservoirs can be identified by the presence of a gas cap with little or no water drive as shown in Figure 11-3.

Due to the ability of the gas cap to expand, these reservoirs are characterized by a slow decline in the reservoir pressure. The natural energy available to produce the crude oil comes from the following two sources:

- Expansion of the gas-cap gas
- Expansion of the solution gas as it is liberated

The Water-Drive Mechanism

Many reservoirs are bounded on a portion or all of their peripheries by water bearing rocks called aquifers. The aquifers may be so large compared to the reservoir they adjoin as to appear infinite for all practical purposes, and they may range down to those so small as to be negligible in their effects on the reservoir performance.

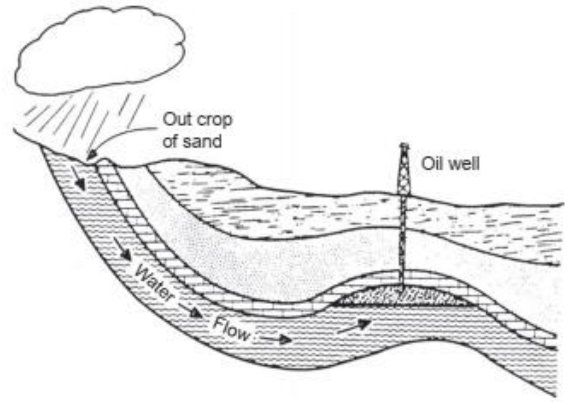


Figure 2.6 Reservoir having artesian water drive. (After Clark, N. J., Elements of Petroleum Reservoirs, SPE, 1969).

The aquifer itself may be entirely bounded by impermeable rock so that the reservoir and aquifer together form a closed (volumetric) unit. On the other hand, the reservoir may be outcropped at one or more places where it may be replenished by surface water as shown schematically in Figure 2.8.

It is common to speak of edge water or bottom water in discussing water influx into a reservoir. Bottom water occurs directly beneath the oil and edge water occurs off the flanks of the structure at the edge of the oil as illustrated in Figure 2.9. Regardless of the source of water, the water drive is the result of water moving into the pore spaces originally occupied by oil, replacing the oil and displacing it to the producing wells.

Cole (1969) presented the following discussion on the characteristics that can be used for identification of the water-driving mechanism:

Reservoir Pressure

The reservoir pressure decline is usually very gradual. Figure 2.9 shows the pressure-production history of a typical water-drive reservoir. It is not uncommon for many thousands of barrels of oil to be produced for each pound per square inch drop in reservoir pressure. The reason for the small decline in reservoir pressure is that

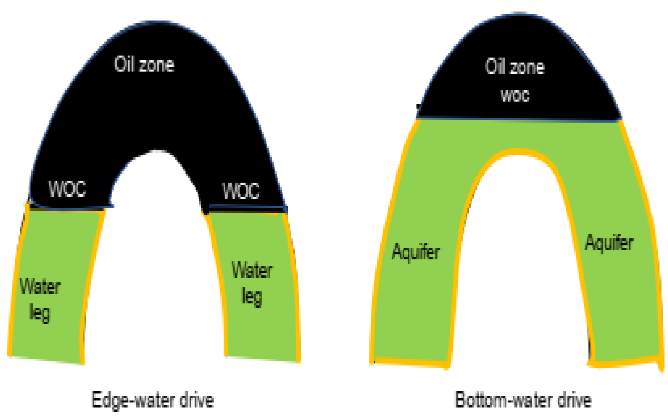


Figure 2.9 Edge and bottom-water drive.

oil and gas withdrawals from the reservoir are replaced almost volume for volume by water encroaching into the oil zone.

Several large oil reservoirs in the Gulf Coast areas of the United States have such active water drives that the reservoir pressure has declined only about 1 psi per million barrels of oil produced. Although pressure history is normally plotted versus cumulative oil production, it should be understood that total reservoir fluid withdrawals are the really important criteria in the maintenance of reservoir pressure. In a water-drive reservoir, only a certain number of barrels of water can move into the reservoir as a result of a unit pressure drop within the reservoir.

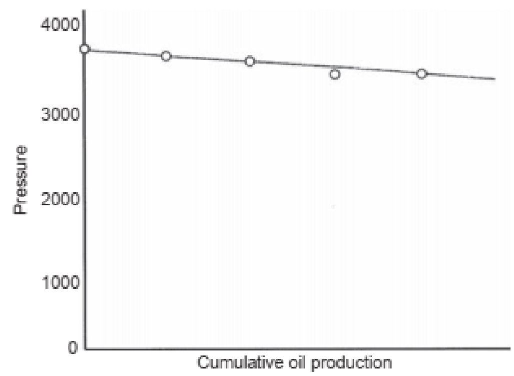


Figure 2.10 Pressure-production history for a water-drive reservoir.

Since the principal income production is from oil, if the withdrawals of water and gas can be minimized, then the withdrawal of oil from the reservoir can be maximized with minimum pressure decline. Therefore, it is extremely important to reduce water and gas production to an absolute minimum. This can usually be accomplished by shutting in wells producing large quantities of these fluids and, where possible, transferring their allowable to other wells producing with lower water-oil or gas-oil ratios.

__Water Production__

Early excess water production occurs in structurally low wells. This is characteristic of a water-drive reservoir, and, provided the water is encroaching in a uniform manner, nothing can or should be done to restrict this encroachment, as the water will probably provide the most efficient displacing mechanism possible.

If the reservoir has one or more lenses of very high permeability, then the water may be moving through this more permeable zone. In this case, it may be economically feasible to perform remedial operations to shut off this permeable zone producing water. It should be realized that in most cases the oil that is being recovered from a structurally low well will be recovered from wells located higher on the structure and any expenses involved in remedial work to reduce the water-oil ratio of structurally low wells may be needless expenditures.

Gas-Oil Ratio

There is normally little change in the producing gas-oil ratio during the life of the reservoir. This is especially true if the reservoir does not have an initial free gas cap. Pressure will be maintained as a result of water encroachment and therefore there will be relatively little gas released from this solution.

Ultimate Oil Recovery

Ultimate recovery from water-drive reservoirs is usually much larger than recovery under any other producing mechanism. Recovery is dependent upon the efficiency of the flushing action of the water as it displaces the oil. In general, as the reservoir heterogeneity increases, the recovery will decrease, due to the uneven advance of the displacing water. The rate of water advance is normally faster in the zones of high permeability. This results in earlier high water-oil ratios and consequent earlier economic limits. Where the reservoir is more or less homogeneous, the advancing waterfront will be more uniform, and when the economic limit, due primarily to high water-oil ratio, has been reached, a greater portion of the reservoir will have been contacted by the advancing water. Ultimate oil recovery is also affected by the degree of activity of the water drive. In a very active water drive where the degree of pressure maintenance is good, the role of solution gas in the recovery process is reduced to almost zero, with maximum advantage being taken of the water as a displacing force. This should result in maximum oil recovery from the reservoir. The ultimate oil recovery normally ranges from 35% to 75% of the original oil in place.

The Gravity-Drainage-Drive Mechanism

The mechanism of gravity drainage occurs in petroleum reservoirs as a result of differences in densities of the reservoir fluids. The effects of gravitational forces can be simply illustrated by placing a quantity of crude oil and a quantity of water in a jar and agitating the contents. After agitation, the jar is placed at rest, and the denser fluid (normally water) will settle to the bottom of the jar, while the less dense fluid (normally oil) will rest on top of the denser fluid. The fluids have separated as a result of the gravitational forces acting on them.

The fluids in petroleum reservoirs have all been subjected to the forces of gravity, as evidenced by the relative positions of the fluids, i.e., gas on top, oil underlying the gas, and water underlying oil. The relative positions of the reservoir fluids are shown in Figure 2.11. Due to the long periods of time involved in the petroleum accumulation-and-migration process, it is generally assumed that the reservoir fluids are in equilibrium. If the reservoir fluids are in equilibrium, then the gas-oil and oil-water contacts should be essentially horizontal.

Although it is difficult to determine precisely the reservoir fluid contacts, best available data indicate that, in most reservoirs, the fluid contacts actually are essentially horizontal. Gravity segregation of fluids is probably present to some degree in all petroleum reservoirs, but it may contribute substantially to oil production in some reservoirs depending on the degree of the reservoir dip angle.

The Combination-Drive Mechanism

The driving mechanism most commonly encountered is one in which both water and free gas are available in some degree to displace the oil toward the producing wells. The most common type of drive encountered, therefore, is a combination-drive mechanism as illustrated in Figure 2.12.

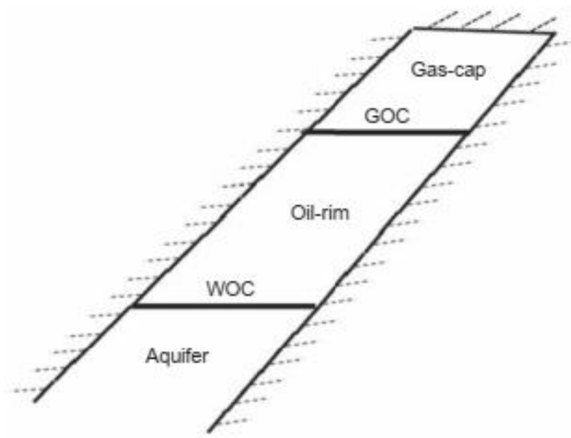


Figure 2.11 Initial fluids distribution in a combination-drive oil reservoir.

Two combinations of driving forces resulting from the present of a gas-cap and an aquifer. The ultimate recovery factor from this combination drive mechanism is a strong function of:

- Size of the gas cap
- Strength of the aquifer
- Wells' locations in reference to GOC and WOC
- Managing and controlling production rate to avoid or delay gas and water coning
- For tilted reservoirs, gravity segregation can play an important role in providing additional recovery by allowing liberated gas to migrate to the gas cap

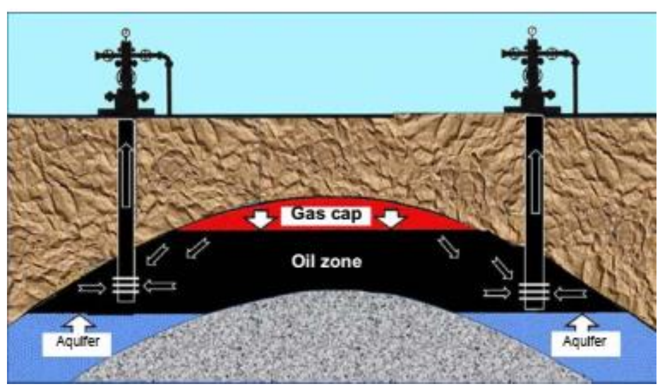


Figure 2.12 Combination-drive mechanisms.

Combination-drive reservoirs can be recognized by the occurrence of a combination of some of the following factors:

a. Relatively rapid pressure decline. Water encroachment and/or external gas cap expansion are insufficient to maintain reservoir pressures.

b. Water encroaching slowly into the lower part of the reservoir. Structurally low producing wells will exhibit slowly increasing water producing rates due to water coning. To delay or minimize water coning; production wells located near the WOC should be reduced to or below well critical flow rate.

c. If a small gas cap is present the structurally high wells will exhibit continually increasing gas-oil ratios, due to the occurrence of gas-coning. To delay or minimize gas coning; production wells should periodically shut-in and productions wells should be controlled at or below critical flow rate.

d. Ultimate recovery from combination-drive reservoirs is usually greater than recovery from depletion-drive reservoirs but less than recovery from water drive or gas-cap-drive reservoirs. Actual recovery will depend upon the degree to which the up-dip wells located near the GOC and down-dip wells located near the WOC are managed by controlling their production rates not to exceed the calculated critical rates.

2.2.4 The Material Balance Equation

The material balance equation (MBE) has long been recognized as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance. The MBE, when properly applied, can be used to:

- Estimate initial hydrocarbon volumes in place
- Predict future reservoir performance
- Predict ultimate hydrocarbon recovery under various types of primary driving mechanisms

The equation is structured to simply keep inventory of all materials entering, leaving, and accumulating in the reservoir. The concept of the material balance equation was presented by Schilthuis in 1941. In its simplest form, the equation can be written on volumetric basis as:

Initial volume = volume remaining + volume removed

Since oil, gas, and water are present in petroleum reservoirs, the material balance equation can be expressed for the total fluids or for any one of the fluids presents. Before deriving the material balance, it is convenient to denote certain terms by symbols for brevity. The symbols used conform where possible to the standard nomenclature adopted by the Society of Petroleum Engineers.

$$N = \frac{N_p\left[B_t + (R_p - R_{si})B_g\right] - (W_e - W_p B_w)}{(B_t - B_{ti}) + m B_{ti}\left[\frac{B_g}{B_{gi}} - 1\right] + B_{ti}(1+m)\left[\frac{S_{wi}c_w + c_f}{1 - S_{wi}}\right]\Delta p}$$ **… … ... Eq. 2.19**

The four major primary driving mechanisms by which oil may be recovered from oil reservoirs are:

a. *Depletion Drive.* Depletion drive is the oil recovery mechanism wherein the production of the oil from its reservoir rock is achieved by the expansion of the original oil volume with all its original dissolved gas.

$$DDI = N(B_t - B_{ti})/A$$ **… … ... Eq. 2.20**

where DDI is termed the depletion-drive index.

b. *Segregation Drive.* Segregation drive (gas-cap drive) is the mechanism wherein the displacement of oil from the formation is accomplished by the expansion of the original free gas cap.

$$SDI = \left[Nm\, B_{ti}(B_g - B_{gi})/B_{gi}\right]/A$$ **… … ... Eq. 2.21**

where SDI is termed the segregation-drive index.

c. *Water Drive.* Water drive is the mechanism wherein the displacement of the oil is accomplished by the net encroachment of water into the oil zone.

$$WDI = (W_e - W_p\, B_w)/A$$ **… … ... Eq. 2.22**

where WDI is termed the water-drive index.

d. *Expansion Drive.* For undersaturated oil reservoirs with no water influx, the principal source of energy is a result of the rock and fluid expansion. Where all the other three driving mechanisms are contributing to the production of oil and gas from the reservoir, the contribution of the rock and fluid expansion to the oil recovery is too small and essentially negligible and can be ignored.

2.2.5 Volumetric Method

Porosity may be classified according to the mode of origin as original induced.

The original porosity is that developed in the deposition of the material, while induced porosity is that developed by some geologic process subsequent to deposition of the rock. The intergranular porosity of sandstones and the intercrystalline and oolitic porosity of some limestones typify original porosity. Induced porosity is typified by fracture development as found in shales and limestones and by the slugs or solution cavities commonly found in limestones. Rocks having original porosity are more uniform in their characteristics than those rocks in which a large part of the porosity is included. For direct quantitative measurement of porosity, reliance must be placed on formation samples obtained by coring.

Since effective porosity is the porosity value of interest to the petroleum engineer, particular attention should be paid to the methods used to determine porosity. For example, if the porosity of a rock sample was determined by saturating the rock sample 100% with a fluid of known density and then determining, by weighing, the increased weight due to the saturating fluid, this would yield an effective porosity measurement because the saturating fluid could enter only the interconnected pore spaces. On the other hand, if the rock sample were crushed with a mortar and pestle to determine the actual volume of the solids in the core sample, then an absolute porosity measurement would result because the identity of any isolated pores would be lost in the crushing process.

One important application of the effective porosity is its use in determining the original hydrocarbon volume in place. Consider a reservoir with an areal extent of A acres and an average thickness of h feet. The total bulk volume of the reservoir can be determined from the following expressions:

$$\text{Bulk volume} = 43,560\ \text{Ah},\ \text{ft}^3 \quad \text{… … ... Eq. 2.23}$$

Or

$$\text{Bulk volume} = 7,758\ \text{Ah}, \text{bbl} \quad \text{… … ... Eq. 2.24}$$

Where:

A = areal extent, acres

h = average thickness

The reservoir pore volume PV can then be determined by combining Equations 2.23 and 2.24. Expressing the reservoir pore volume in cubic feet gives:

$$PV = 43{,}560\ Ah\phi,\ \ ft^3$$ **… … ... Eq. 2.25**

Expressing the reservoir pore volume in barrels gives:

$$PV = 7{,}758\ Ah\phi,\ \ bbl$$ **… … ... Eq. 2.26**

2.2.6 Reserve classification

Petroleum Reserves Definitions (SPE, 1997):

Reserves derived under these definitions rely on the integrity, skill, and judgment of the evaluator and are affected by the geological complexity, stage of development, degree of depletion of the reservoirs, and amount of available data. Use of these definitions should sharpen the distinction between the various classifications and provide more consistent reserves reporting. (SPE, 1997)

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. (SPE, 1997)

The intent of the Society of Petroleum Engineers (SPE) and World Petroleum Council (WPC, formerly World Petroleum Congresses) in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved. (SPE, 1997)

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. (SPE, 1997)

Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting. (SPE, 1997)

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve. (SPE, 1997)

Proved Reserves

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped. (SPE, 1997)

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. (SPE, 1997)

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves. (SPE, 1997)

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests. (SPE, 1997)

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data. (SPE, 1997)

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets. (SPE, 1997)

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed. (SPE, 1997)

Unproved Reserves

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves. (SPE, 1997)

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications. (SPE, 1997)

Probable Reserves

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves. (SPE, 1997)

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved. (SPE, 1997)

Possible Reserves

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area. (SPE, 1997)

2.2.7 Reserve Status Categories (SPE, 1997)

Reserve status categories define the development and producing status of wells and reservoirs.

Developed: Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be subcategorized as producing or non-producing. (SPE, 1997)

Producing: Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation. (SPE, 1997)

Non-producing: Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production. (SPE, 1997)

Undeveloped Reserves: Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects. (SPE, 1997)

CHAPTER THREE

3.1 Methodology

This section briefly discusses the workflow of the project to achieve the aims and objectives described above.

The methods of analysis employed are divided into three major sections:

1- Geology & Geophysics analysis
2- Petrophysical analysis
3- Engineering analysis

The above methods focused on the methods used to develop a reservoir characterization, which include:

- ✓ data reconciliation
- ✓ mapping
- ✓ volumetric
- ✓ material balance

3.1.1 Geology & Geophysics analysis

The seismic data used in this study is represented by 3D seismic cube. The seismic data are further analyzed and interpreted to determine the main structural elements that control the hydrocarbon entrapment in the study area. The reservoir zones in the study area and the different encountered formations are picked.

applied seismic inversion technique to a 3D seismic data to predict porosity for Qishn Clastics Formation and convert 3D seismic data to Acoustic impedance attribute and porosity of well with multi attribute transformer to best predict porosity property in seismic.

To carry out the above, the below steps are followed:

- Load seismic and well data
- Generate Synthetic seismograms (Seismic – Geology Correlation) to match S1A and Basal Sands tops to seismic.
- Horizon and fault Interpretation
- Velocity model – Time Depth Conversion (Q.C)
- Post Stack Inversion to generate an AI volume

Correlate Geology-Seismic

Estimate Wavelet

Generate initial model

Do Inversion at wells then Do Inversion for Whole volume –

Q.C Volume

- Use AI and porosity logs to generate

Porosity-Volume

Multivariate Statistical Analysis –

Neural Network Generate Volume

Q.C Volume.

- Generate Permeability-Volume

Correct Porosity logs using Core Porosity data

Crossplot Porosity vs. Core Permeability

Generate permeability Volume –

Q.C permeability Volume

- Pressure-Volume

Generate Velocity Volume

Q.C Sonics and Check shots

- Generate Iso-Attribute maps for S1A
- Generate Structural maps for both S1A
- Combine maps to generate prospective areas.

3.1.2 Petrophysical analysis:

Suites of wireline logs which include gamma ray, resistivity, sonic, neutron, and bulk density logs were used for this study two wells. In this work, the well log evaluation has been achieved by using the Techlog software. This program determines and calculates the deterministic and probabilistic models including porosity, water saturation, shale volumes and other properties within user-defined zones. The following procedure was done for petrophysical analysis:

1- Log editing and quality check

The well log data (composite log) are provided as LAS and ASCII formats. Before analyses, the data quality check is performed on each set of well log. No major well log editing is required, as all the well logs are up to the standard to conduct the interpretation.

2- Log interpretation:

a- <u>Lithology discrimination</u>

The gamma ray and density logs are very useful to discriminate lithology. On the basis of gamma ray log sandstones, shales and carbonates sequences can be marked (Soto et al., 2010). For this study gamma ray readings are used to define different lithologies. Furthermore, to distinguish sandstone and carbonate the density log is used parallel with the gamma ray log.

b- <u>Clay Volume</u>

The Clay volume interpretation module is used to interactively calculate clay volume from multiple clay indicators. Clay volume was calculated from single curve (e.g. gamma ray (GR), spontaneous potential (SP), and deep resistivity responses (RESD), and double curve (e.g. Sonic/Neutron, Neutron/density, and Sonic/density curves).

c- <u>Porosity estimation:</u>

Porosity is the pore volume of the rock. It can be filled with hydrocarbons, moveable water, capillary water or clay bound water. Its unit can be fraction or percentage. In this study, the porosity estimation is based on two well logs (Neutron, and Density log). For better understanding of the reservoir, effective porosity is calculated. Effective porosity mostly used in marking the reservoir intervals from the gross interval.

d- <u>Water Saturation</u>

Water saturation is calculated by using the Indonesian Equation in Techlog software. Cement value (m) is taken as 1.5; tortuosity factor (n) is taken as 2. Deep resistivity values are used from LLD. On the basis of water saturation, pay zone is separated from reservoir intervals. The Rw values are estimated by using Pickett plot.

e- <u>Net-to-Gross and pay zone</u>

Gross interval is a total thickness of the reservoir formation. It includes all zones (productive zone, non-productive zone, tight zone, shaly or silty zone), no cutoff has applied. Net reservoir interval contains the rock of good reservoir quality sorted by Vsh and porosity cutoff. Net reservoir interval also contained the fully water saturated and hydrocarbon saturated zones. Pay zone interval contained the commercially producible hydrocarbon. Pay zone interval obtained by putting the cut off values of water saturation as well. Pay zone also eliminate depth below the Oil-Water-Contact (OWC), which is fully water

On the basis of the effective porosity, Vsh and water saturation, reservoir intervals and net pay zones are marked from the gross formation intervals. In this study for defining the reservoir interval, the effective porosity is greater than 10% and volume of shale less than 35% are used. For net pay or producible zones marking, water saturation less than 50% are taken along with the other parameters defined early.

3.1.3 Engineering analysis:

The engineering work will be focused on the following procedure

- Evaluation of the hydrocarbon potentiality of reservoir in the study area based on the results of well petrophysics and seismic analysis
- Choose the attractive area for future development based on the created maps
- Calculate S1A STOIIP by using volumetric method and Material balance method then compare the results of two methods.
- Identify reservoir drive mechanism and strength of aquifer using material balance

3.2 Data Required

The data required to characterize a reservoir are:

1- Regional data
2- 2D and 3D seismic (mapping, cross sections, seismic sequences, etc.)
3- Mud logging (shows, losses, Lithology description from cuttings)
4- Cores (Sedimentology, petrophysical parameters (static and dynamic)
5- Wireline logging (correlations and porosity, water saturation and net pay)
6- MDT (mobility, contacts and heterogenies)
7- PVT data (fluid properties)
8- Tests (reservoir geometry and dynamic characteristics)
9- Production and pressure data

3.3 Software used Description

This study utilizes different software packages, described as the following:

3.3.1 Microsoft Office Package:

Microsoft Office 2021 (Excel, Word and PowerPoint) is used to handle the data, writing graduate project and making presentations for the group discussion and the final graduate project defense

3.3.2 Schlumberger Techlog Platform 2015.2

Techlog software is used for most of the petrophysical analysis, to generate the crossplots , visualize, interpret, and edit all of your wellbore data. (Schlumberger Techlog magazine, 2011).

In his study Schlumberger Techlog will be used primarily to find the following properties:

- Shale volume
- Porosity
- Water saturation
- Permeability

As well as, making N-D cross-plots to determine the lithology, 3D cross-plots for shale volume verification with the wellsite geologist report, and Pickeet plot to determine Rw.

3.3.3 Schlumberger Petrel Platform 2018

Petrel is a software platform used in the exploration and production sector of the petroleum industry. It allows the user to interpret seismic data, perform well correlation, build reservoir models, visualize reservoir simulation results, calculate volumes, produce maps and design development strategies to maximize reservoir exploitation. Risk and uncertainty can be assessed throughout the life of the reservoir interface of the software.

The Petrel* E&P software platform enables reservoir engineers to collaborate effortlessly with each other, as well as with geoscience, geomechanics, and production specialists. Combining knowledge from all these disciplines into a single, model-centric subsurface representation means that changes in seismic interpretation, in the geological model, or in newly acquired well data easily cascade through to the simulation model (Schlumberger Petrel Reservoir Engineering, 2015).

In this study the primary uses of Schlumberger Petrel Platform 2018 are as follows:

- Input and visualization of well, and seismic data as well as seismic interpretation results.
- Making surfaces from structural grids and polygons.
- Generating structural maps.
- Extracting seismic attributes on to generated surfaces.

3.3.4 Integrated Petroleum Management Experts (IPM)

MPAL is an analytical reservoir engineering toolkit. In this study it will be used to perform the following procedures on North Camaal:

- Material Balance calculations.
- History Matching.
- Description of the reservoir driving mechanisms.

3.3.5 Hampson & Russel

HampsonRussell Software is a comprehensive suite of reservoir characterization tools that integrate well logs, seismic data and geophysical processes into an easily navigated intuitive package for fast results. Known for its ease of use, HampsonRussell makes sophisticated geophysical techniques accessible to all geophysicists (HampsonRussell Overview Brochure, 2021)

3.3.6 SMT (IHS Kingdom)

Applying seismic inversion to predict reservoir properties is traditionally performed with specialist software packages where it is common for the geophysicist to spend more time with data import, QC, and export rather than analyzing and validating the results with the rest of the team.

Kingdom Seismic Inversion helps you get maximum value from your seismic data and make the best use of your time by providing advanced and integrated pre stack and post stack seismic inversion so you can spend the most time in areas of the workflow that are the most important (IHSMarkit Kingdom™ Seismic Inversion, 2021).

3.4 Steps of Study

1. Loading of wells data of (NC-4 and NC-8) into the Petrel and Techlog including (Well data, Formation tops, sonic logs, Neutron logs, GR and Density logs).
2. Loading of seismic 3D PSTM data to Kingdom
3. Tying seismic to well and generating synthetic seismogram
4. Depending on Formation tops and interpreter piking of targeted reflectors has been done for Qshin Clastic Formation
5. After tracking the reflectors, a TWT map generated for the top and bottom of the reflectors
6. Velocity model calculated in order to construct a depth and average velocity maps
7. Seismic attribute volumes generated and analyzed for the seismic cubes.
8. Genetic inversion method applied to construct acoustic impedance (AI) volume and then to the porosity volume, permeability volume and pore pressure volume
9. Shale volume (VShale) calculated from Gamma ray (GR) logs
10. Effective Porosity calculated from Neutron, density and sonic logs and corrected by subtracting Vshale
11. Water saturation and net pay thickness are calculated
12. STOIIP calculation using volumetric and dynamic (MBE) methods

3.5 Expected Outcomes:

The main output data expected to characterization are:

Maps, porosity, permeability, water saturation, pay thickness, fluid properties, and reservoir pressure as well as potential hydrocarbon. Reconciliation of each of these properties is discussed below:

1- **Reservoir Maps**: There are two categories of reservoir maps: geological maps and production maps. Geological maps include structure, gross pay, net pay, porosity-pay, and hydrocarbon porosity-pay maps as well as structural and stratigraphic cross sections (seismic and wireline logs).

2- **Porosity** is determined from conventional core and well log data. Typically, core data are more accurate because porosity is measured directly. The recommended approach is to compare core and log porosities at the same depth for each well that has been both cored and logged. The log porosities are adjusted to match the core data either by adjusting the inputs into the log calibration (e.g., matrix density or matrix transit time) or by using an appropriate averaging formula. If there are insufficient data to match core and log data directly, then the overall average core porosity can be compared with overall average log porosity. Sometimes, seismic information is available for the reservoir. Seismic attributes such as amplitude and impedance may be compared to average porosity at the well to establish a relationship between the attributes and porosity. Maps of the attributes can then be used to predict porosity away from the wellbores.

3- **Permeability**: Permeability is determined from conventional core data, permeability porosity correlations, pressure transient analysis, Permeability 3D Seismic Volume and production rates. None of these methods provides a direct measurement of in situ permeability and the permeability distribution. The best results are obtained if all four methods for determining permeability can be used together.

4- **Water Saturation**: Water saturation is determined from well logs, relative permeability data, and capillary pressure data. If the wettability of the core has not been altered, the relative permeability and capillary pressure data usually give the best measure of the irreducible water saturation. The best results are obtained from cores drilled with an oil-based mud and collected from the oil zone above the transition zone.

5- **Pay Thickness and Fluid Contacts:** Pay thickness is determined from well logs and core data. Often there are insufficient core data to determine pay thickness independently. Instead, the core data provide a check on the log interpretation. Net pay thickness depends on the choice of porosity, water saturation, and shale content cutoffs.

   Fluid contacts are determined from well logs and are sometimes inferred from pressure survey or production data.

6- **Reservoir pressure:** is determined from well testing and pressure survey.

CHAPTER FOUR

Interpretation and Results

In this chapter an integrated geology & geophysics, petrophysics and reservoir engineering are carried out to characterize the Qishn sandstone reservoir (North Camaal 3D seismic cube, 2 well logging data and reports, production and injection data for 29 wells in North Camaal field 2012). The chapter focuses exclusively in the discussion and analyzing of the results. In this study, Qishn sandstone is classified into units (S1A, S1B, S1C, S2 and S3). S1A unit attains the most prolific hydrocarbon saturations and is selected in this study for reservoir characteristics.

4.1 Geology and Geophysics

4.1.1 Seismic interpretation

Cross-section in-depth showing Well correlation

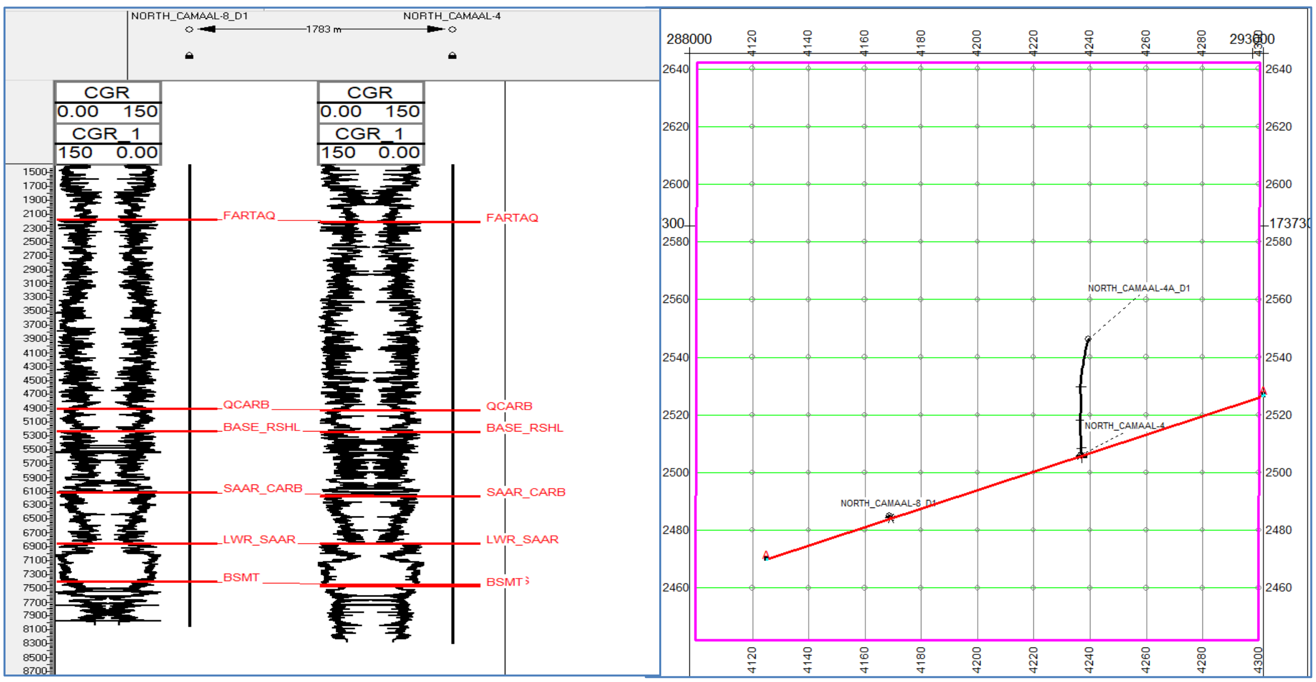


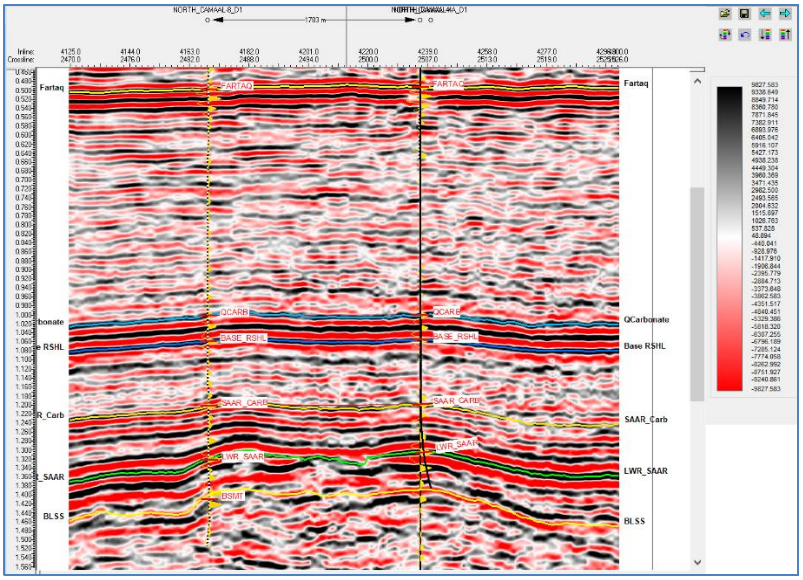
Fig. 4.1 Cross-section in-depth showing Well correlation

Arbitrary Seismic Line showing Seismic – Well correlation

The yellow curves that you can see in fig.4.1 bellow are called *Synthetic Seismograms*

Horizon Interpretation

Fig.4.2 bellow shows Arbitrary Seismic Line showing horizon interpretation for Fartaq, Qishn Carbonate, Base Red Shale, Saar Carbonates, LWR Saar, as well as Basal Sandstone



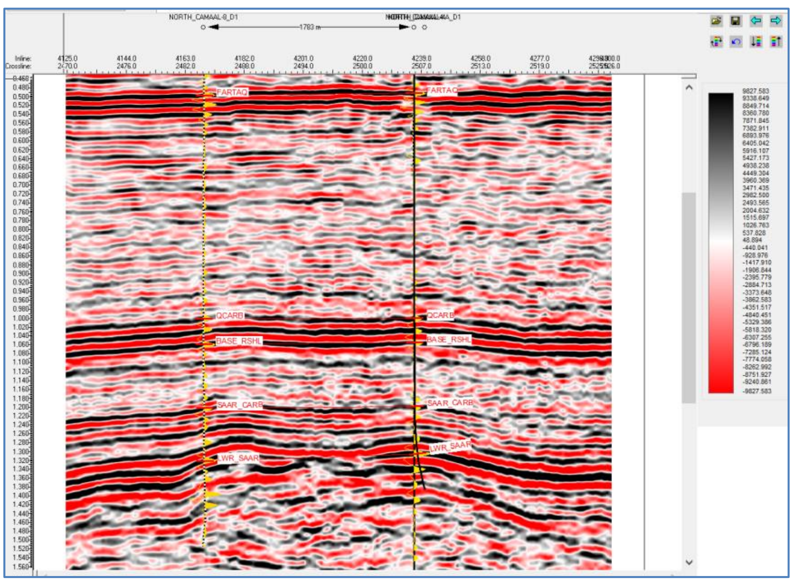
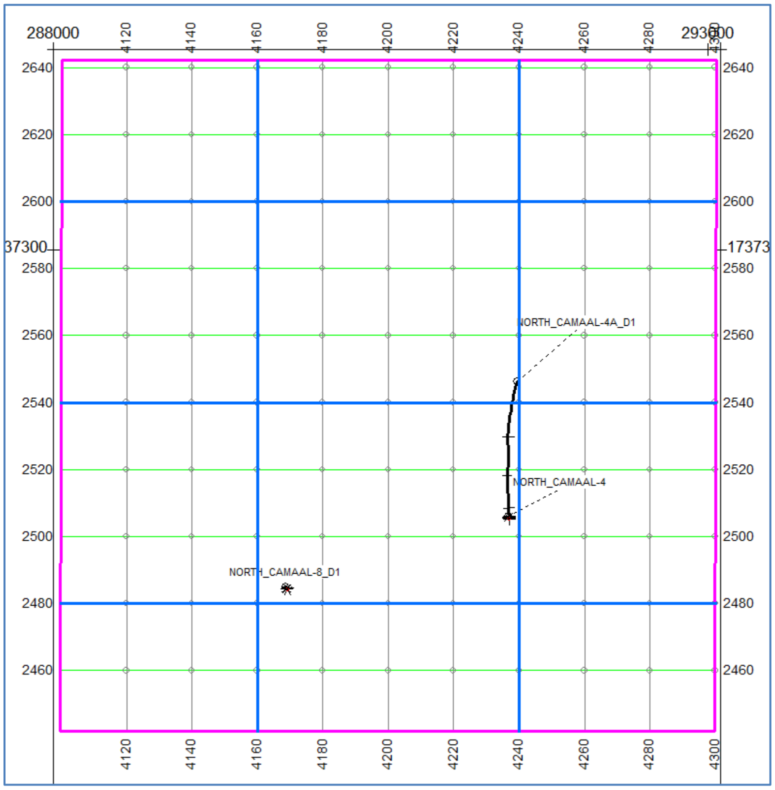


Fig. 4.2 Horizon Interpretation

Base Map

Line 4160 Line 4240

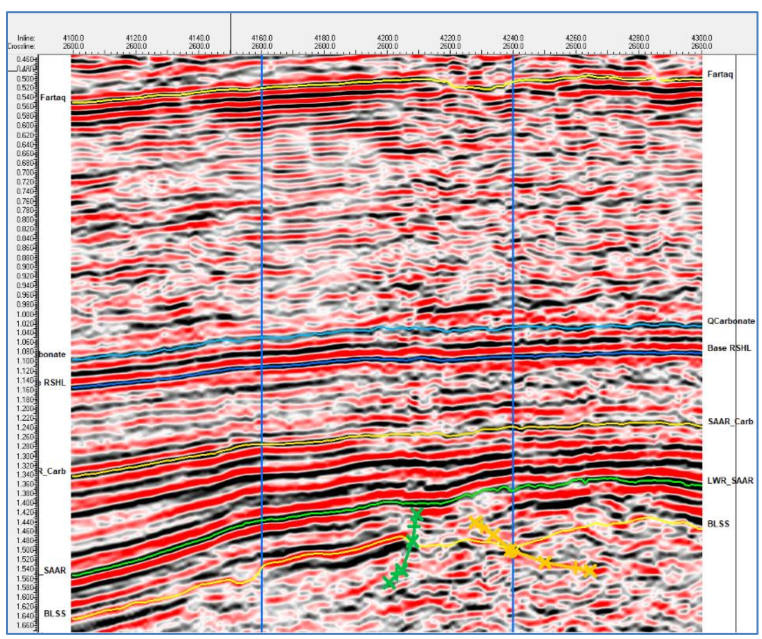


Crossline 2600

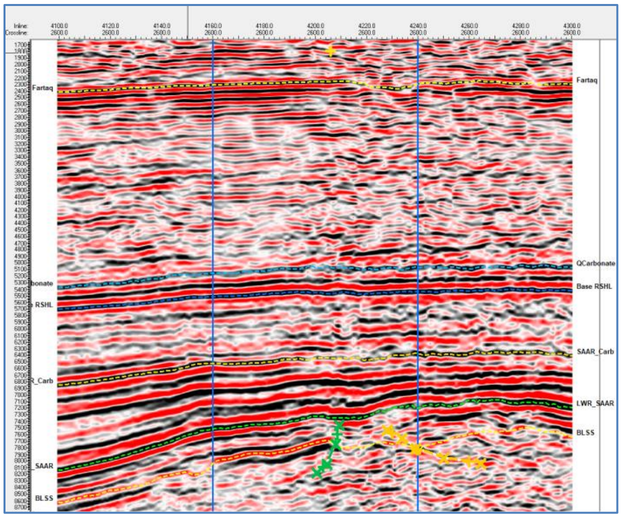
Crossline 2540

Crossline 2480

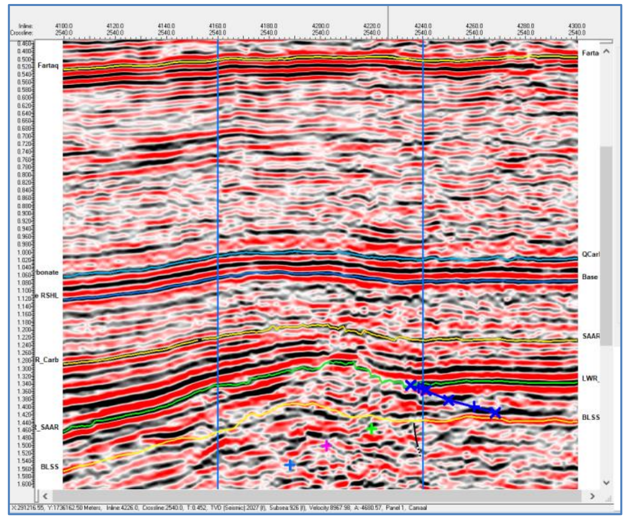
Crossline 2600 Time



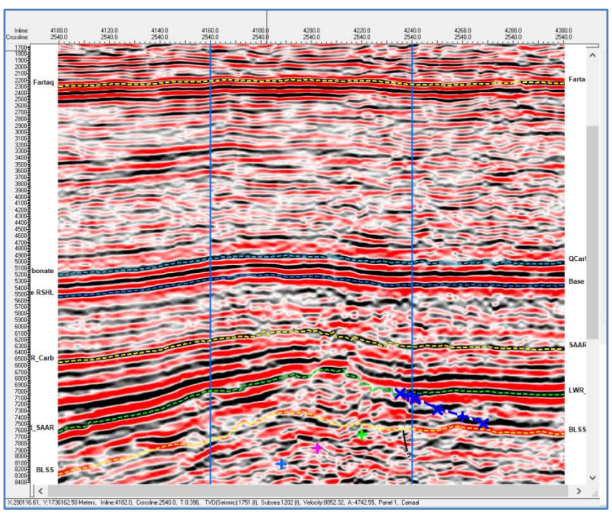
Crossline 2600 Depth



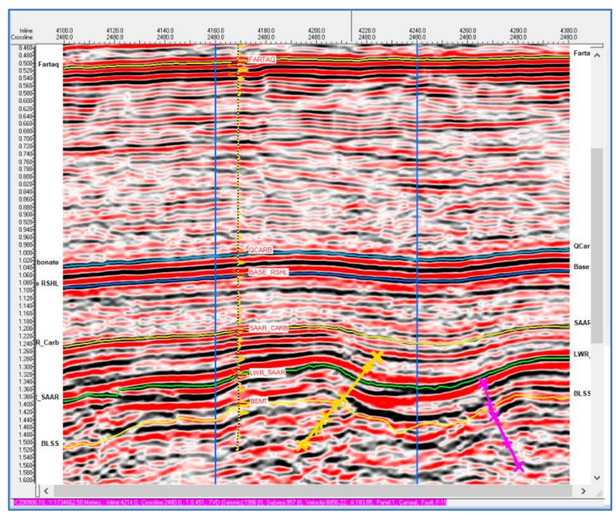
Crossline 2540 Time



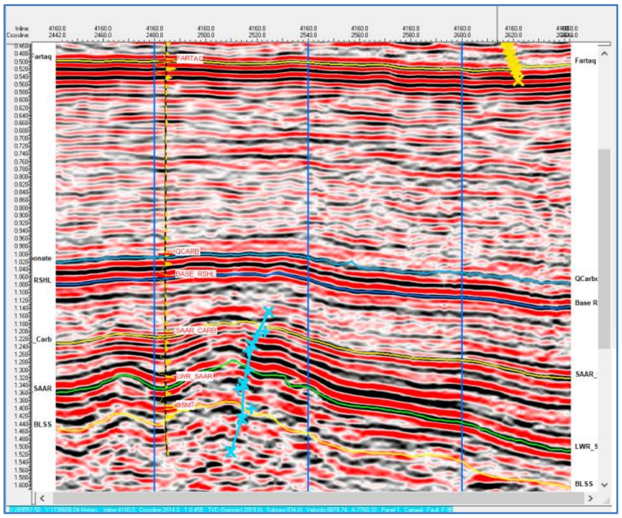
Crossline 2540 Depth



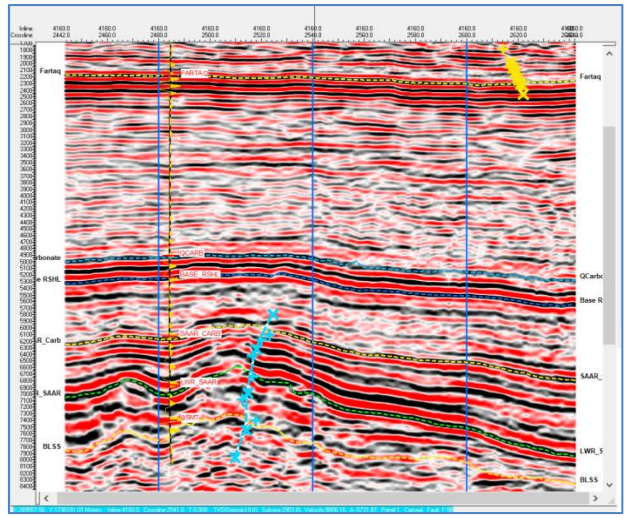
Crossline 2480 Time and Depth



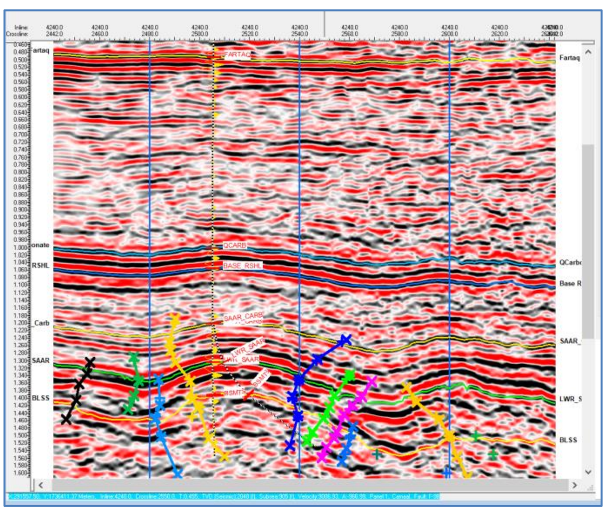
Line 4160 Time



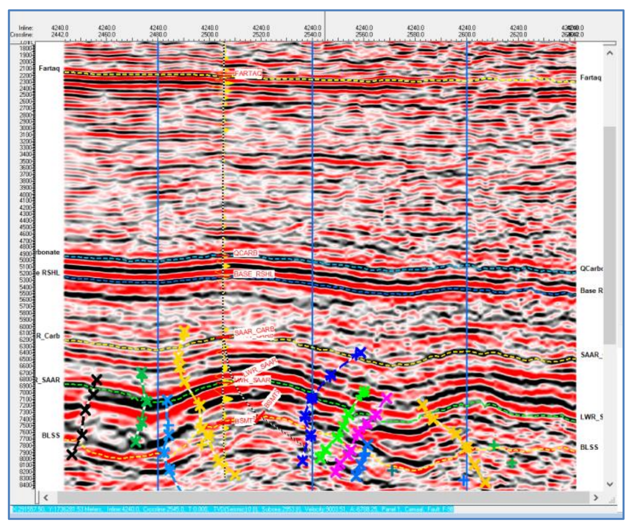
Line 4160 Depth



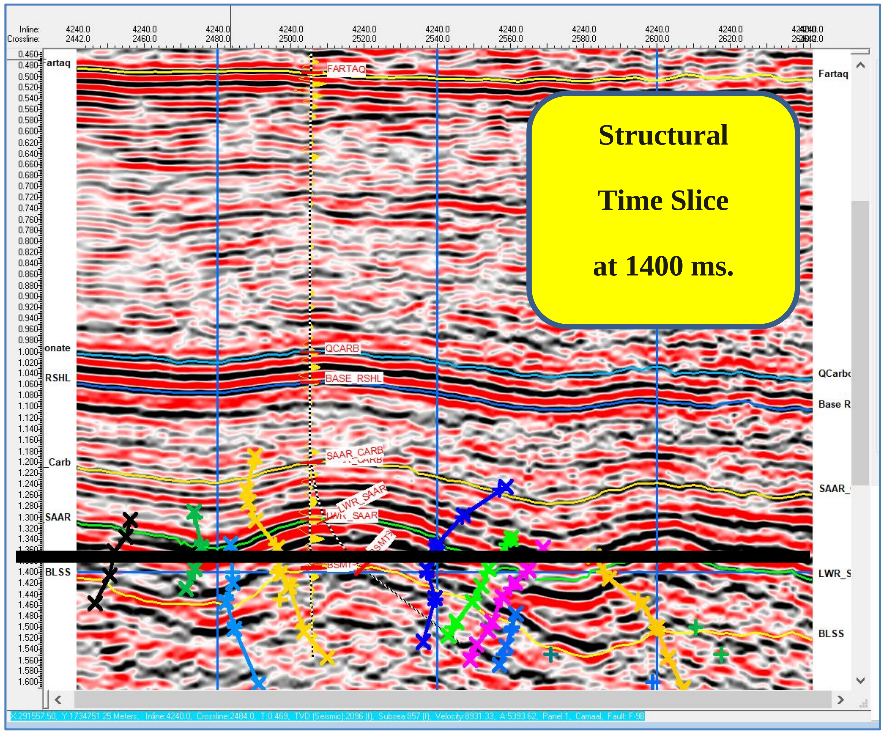
Line 4240 Time

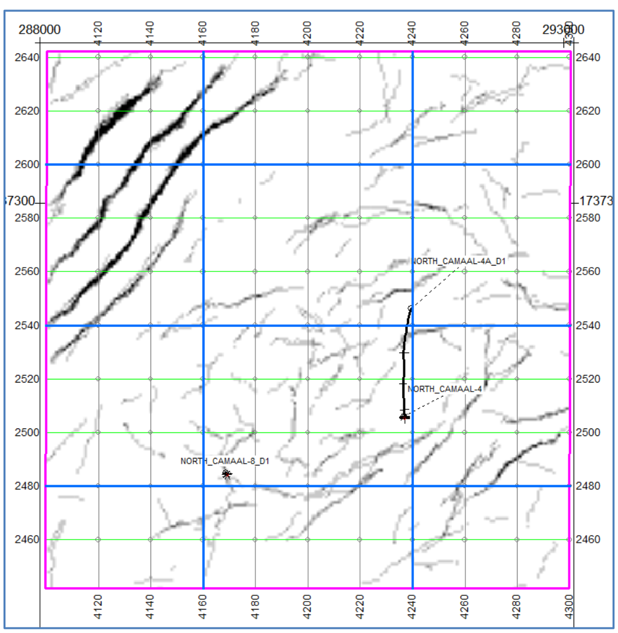


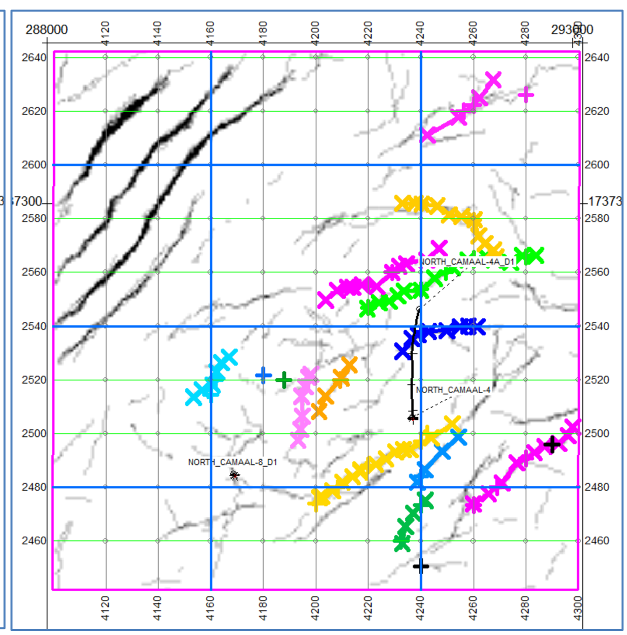
Line 4240 Depth



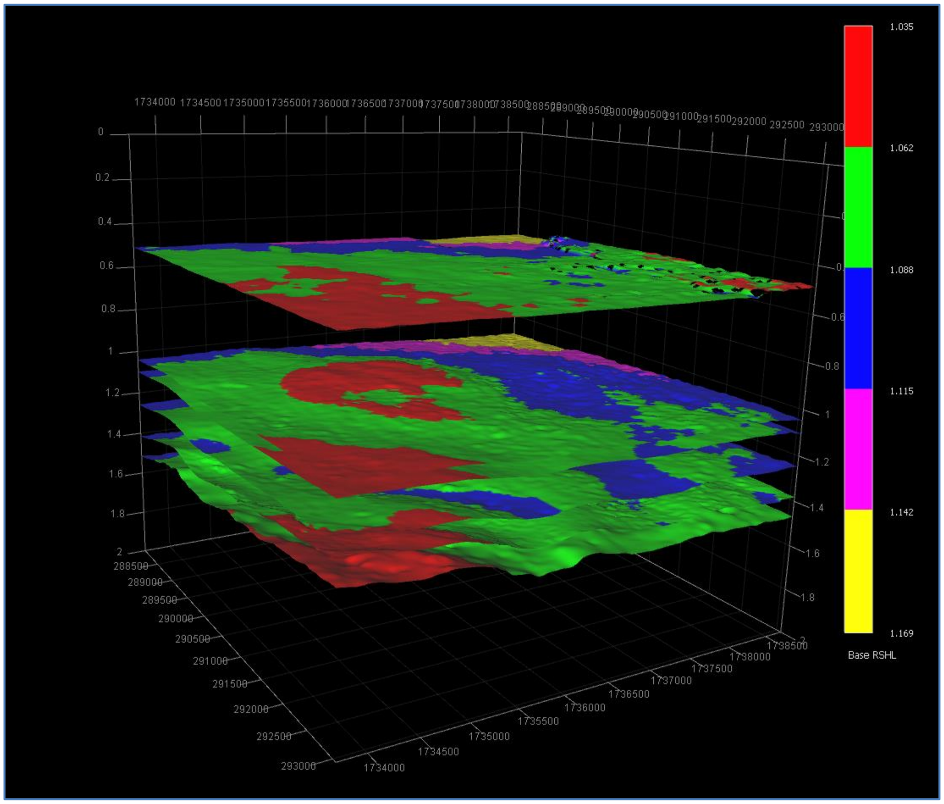
Line 4240 –Fault Interpretation

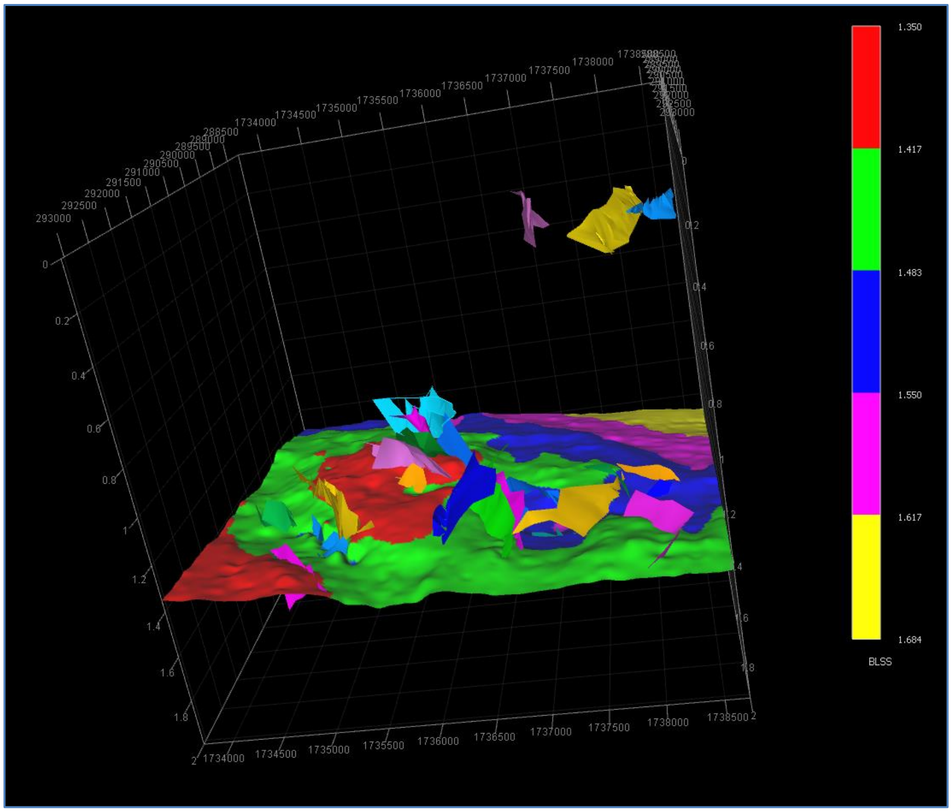






3D Visualization Horizons and Faults

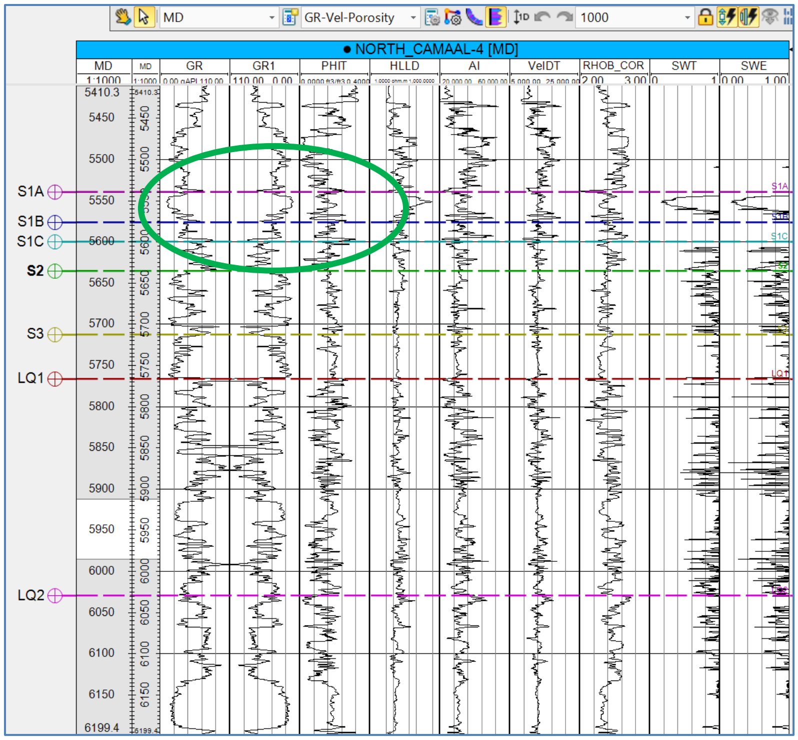


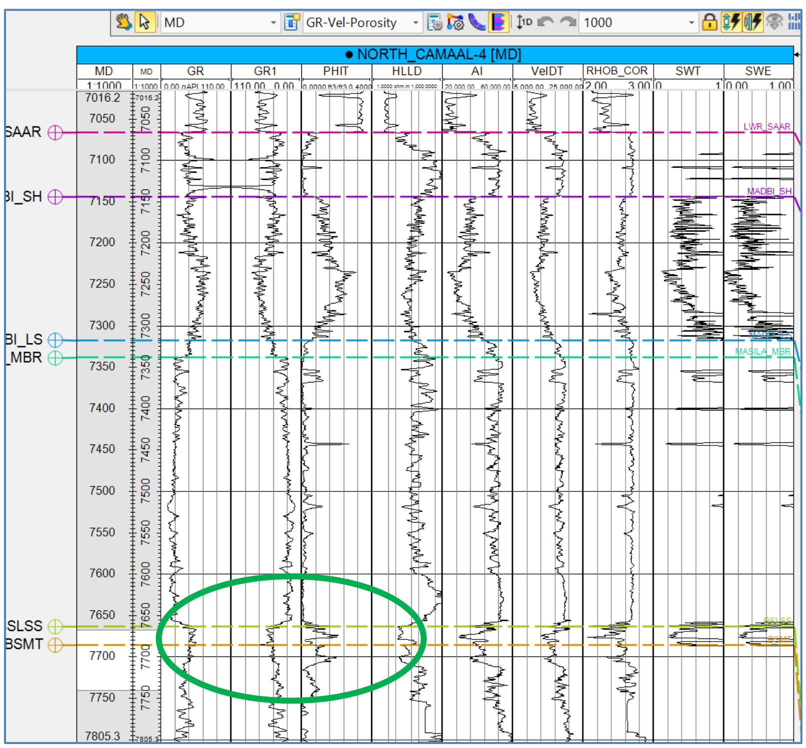


4.1.2 Reservoir Characterization

Porosity

Now, we know what is the vertical areas of interest are S1A Sands and BLSS sands.


NORTH_CAMAAL-4 [MD]
MD
GR
GR1
PHIT
HLLD
AI
VelDT
RHOB_COR
SWT
SWE
S1A
S1B
S1C
S2
S3
LQ1
LQ2


NORTH_CAMAAL-4 [MD]
MD
GR
GR1
PHIT
HLLD
AI
VelDT
RHOB_COR
SWT
SWE
SAAR
BI_SH
BI_LS
_MBR
SLSS
BSMT
LWR_SAAR
MADBI_SH
MASILA_MBR

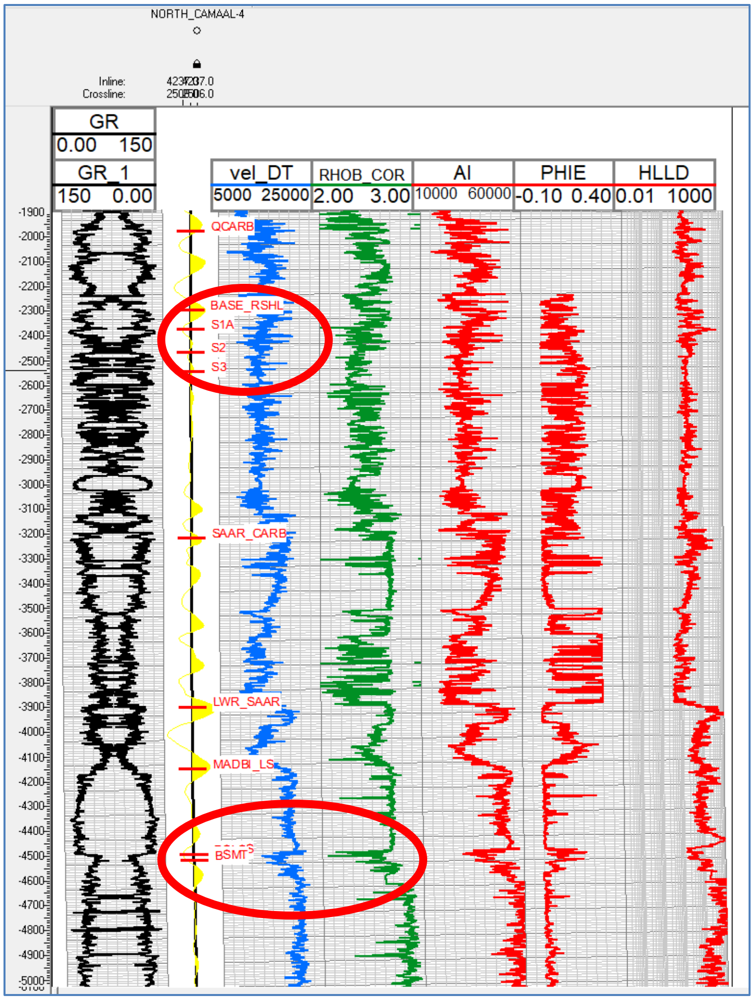


Fig. 4.3 (S1A)

From fig.4.3 above we can see that S1A has:

- High total porosity (PHIT)
- Low Acoustic Impedance (AI)
- Low density (RHOB, Cor)
- High resistivity (HLLD)
- Very low saturation.

Also, from fig.4.3 above we can see that BLSS has:

- High total porosity (PHIT)
- Low Acoustic Impedance (AI)
- Low density (RHOB, Cor)
- Very low saturation
- But very low resistivity meaning (Low oil presence)

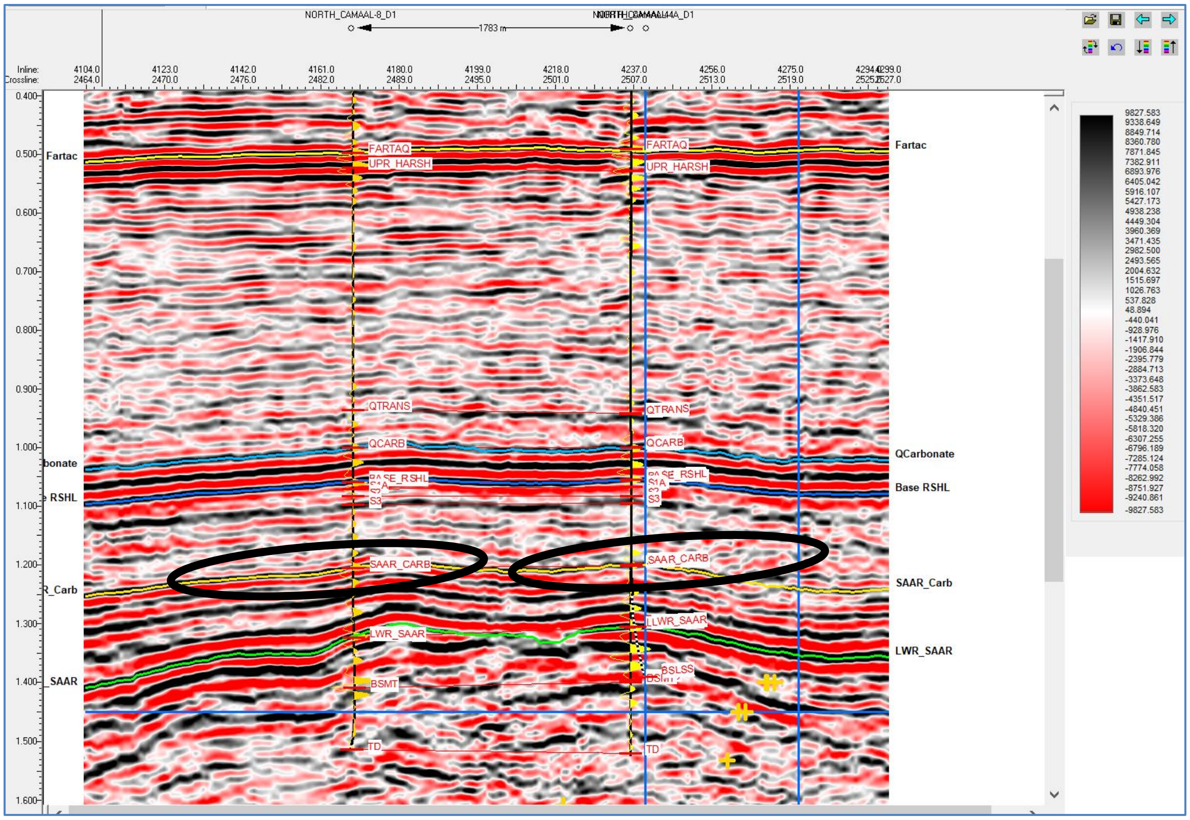


Fig. 4.4 RSHL

This is what it looks like in fig.4.4, we can see that there is a little bit of a structure at the base of RSHL formation which is S1A, S2, S3 sandstone which represents Qishn formation.

Porosity Vs. AI Cross plot

The cross plot for NC-4 bellow in fig.4.5 is showing the Effective Porosity in the vertical y axis and in the x axis the Acoustic Impedance Porosity. Fig.4.18 shows the full interval which means for the whole log, and what we can see is that as we are going to the left, we get low values of AI. So, with low values of AI we are getting high values of porosity.

The black circle in fig.4.18 at around 3000 AI, we can clearly see high values of porosity between 16-23%. The cross plot is color coded with gamma ray, the red values which are between 0 to 30 as we can see from the color pallet in the left, this is our sandstone. Anything greater than 30 is sand with shale.

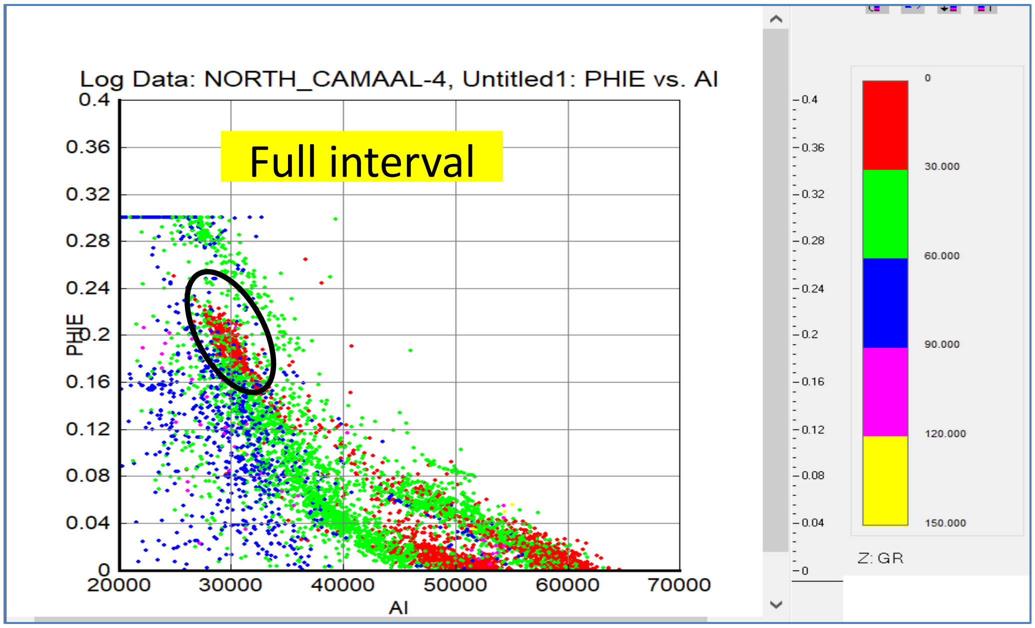


Fig. 4.5 Porosity Vs. AI Cross plot

If we were to go to a smaller scale instead of the full interval, fig.4.6 shows the interval between RSHL to S3 Sandstone.

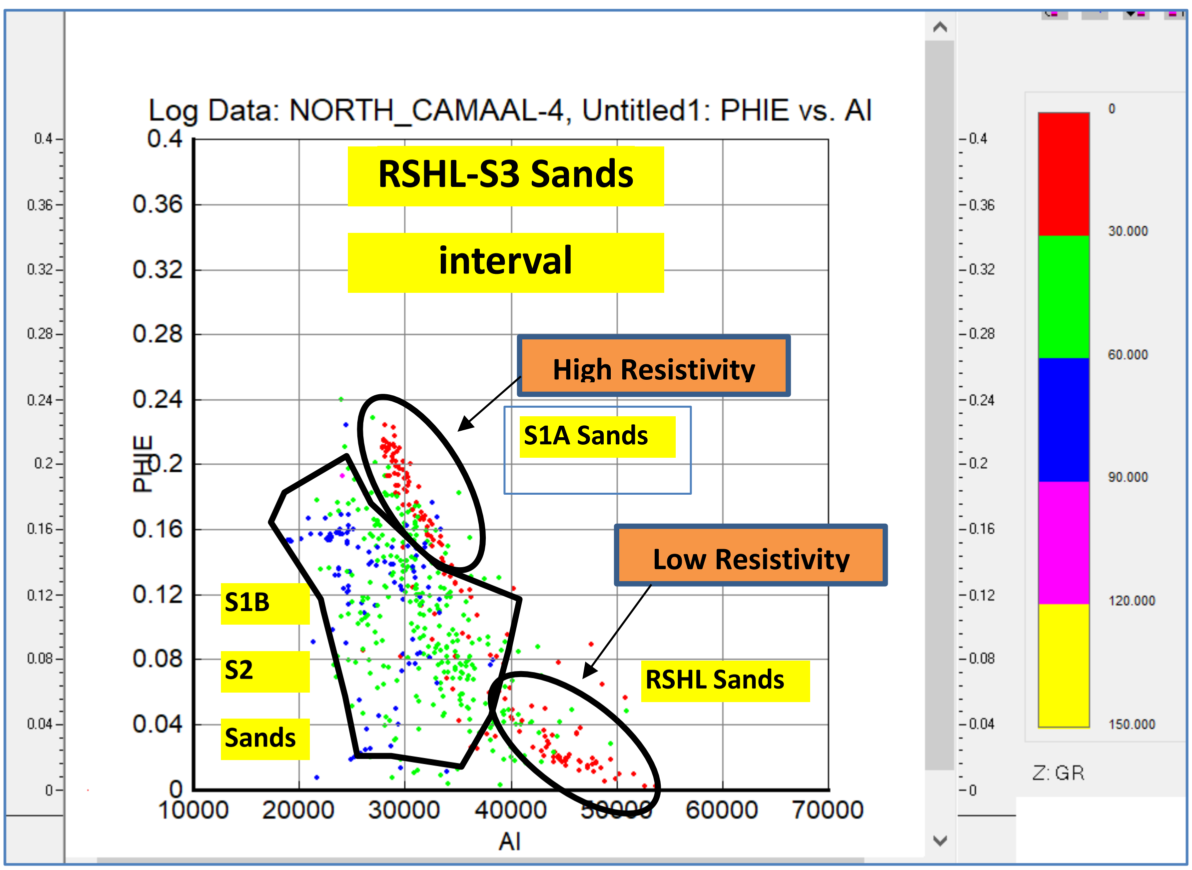
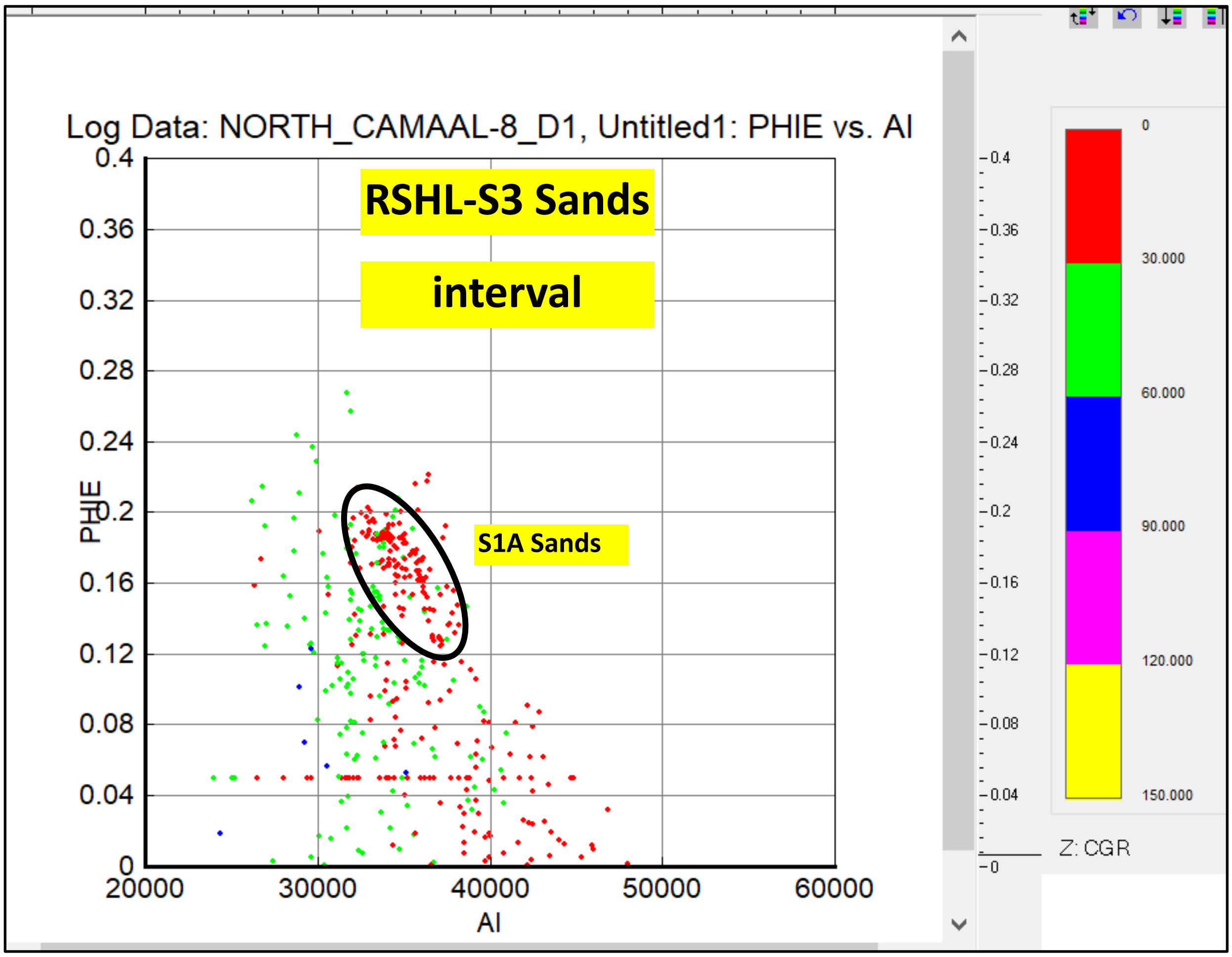


Fig. 4.6 RSHL

Now we can see the red points which represents S1A sandstones, that has high resistivity. Also, the red point at the bottom of the cross plot which represents the RSHL sandstones with low resistivity. So, we can conclude that with low AI values we are going to get high porosity. Which is telling us what we should be looking for when doing the post-Stack conversion, and porosity.

The same is also true for NC-8, we can also see low values of AI, and high values of porosity in S1A sandstone.



Seismic Well – Correlation - Camaal – 4. CF = 0.898

So, now for us to be able to do the post-Stack conversion, we should first correlate the data. Which is what is shown in fig.4.7 bellow.

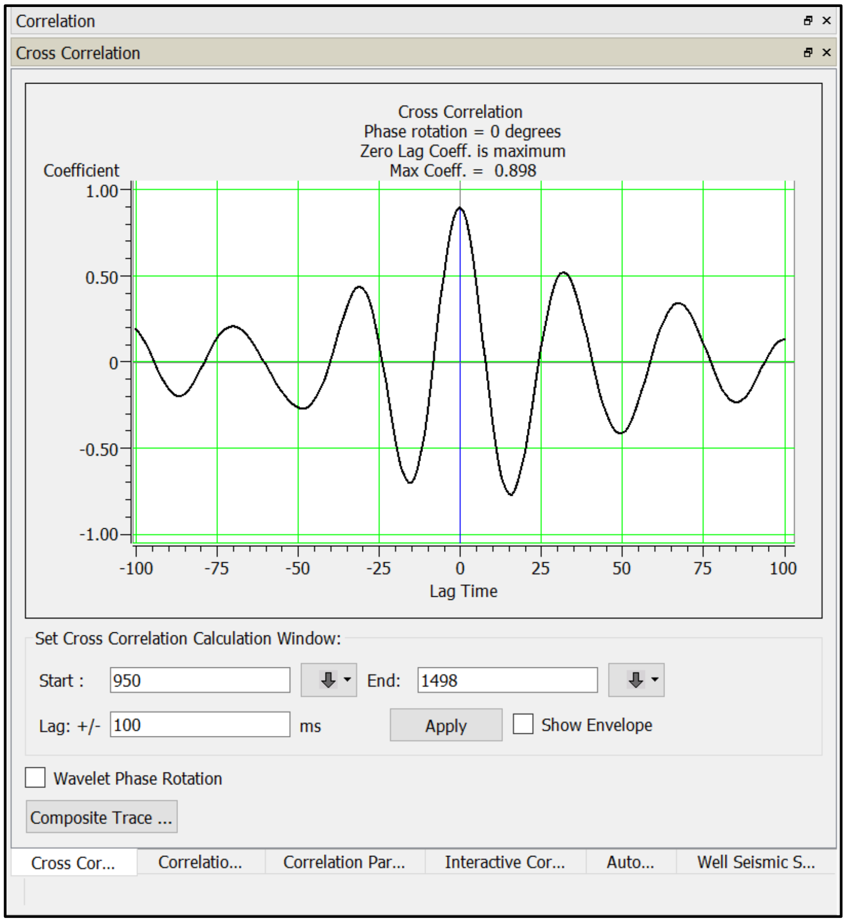


Fig. 4.7 post-Stack conversion

First, we correlated the data, and estimated the wavelets. After that, we built a model. Then we ran the post-Stack conversion at the wells. Then we tested the model at the wells. Finally, we ran it for the whole volume. Once that is done, we will get an Acoustic Impedance for the whole volume, which we will use to create the porosity volume.

Fig.4.8 shows what is just like a synthetic seismogram that we created. In bule, the synthetic we created using the sonic and density. In the red, is what comes out of the seismic trays. We can see that there is a very good match between the picks, in this case the trays are the picks and the no color is the trophy. The correlation between them is 0.898 correlation which is very, very good.

Now we are going to move to building the model.

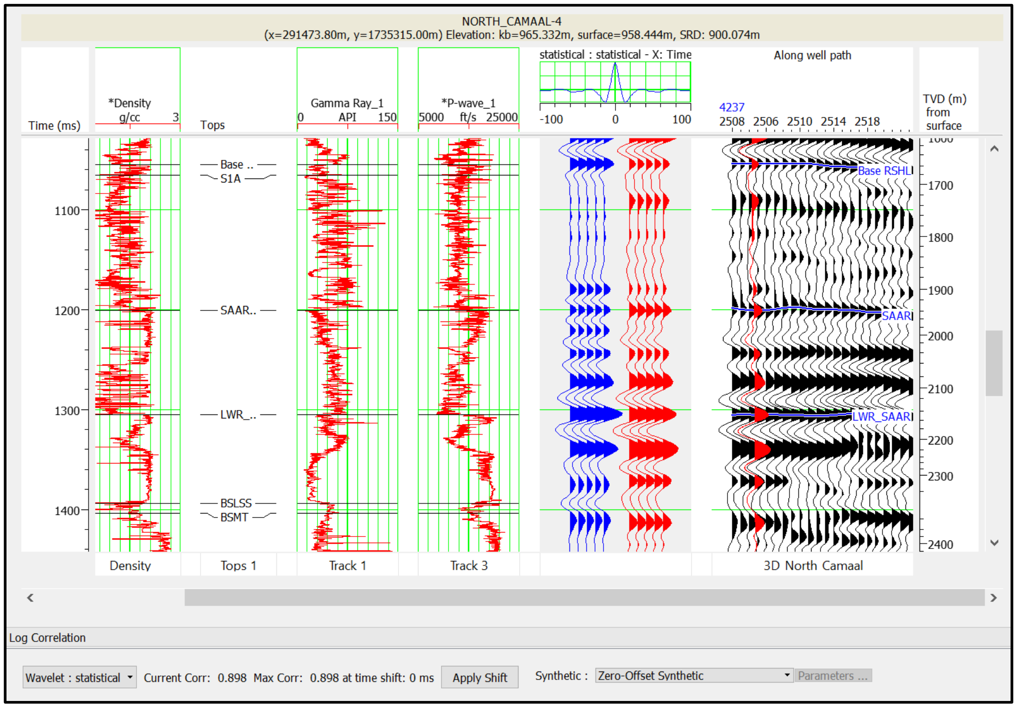


Fig. 4.8 synthetic seismogram

Cross plot Actual Porosity vs Predicted Porosity

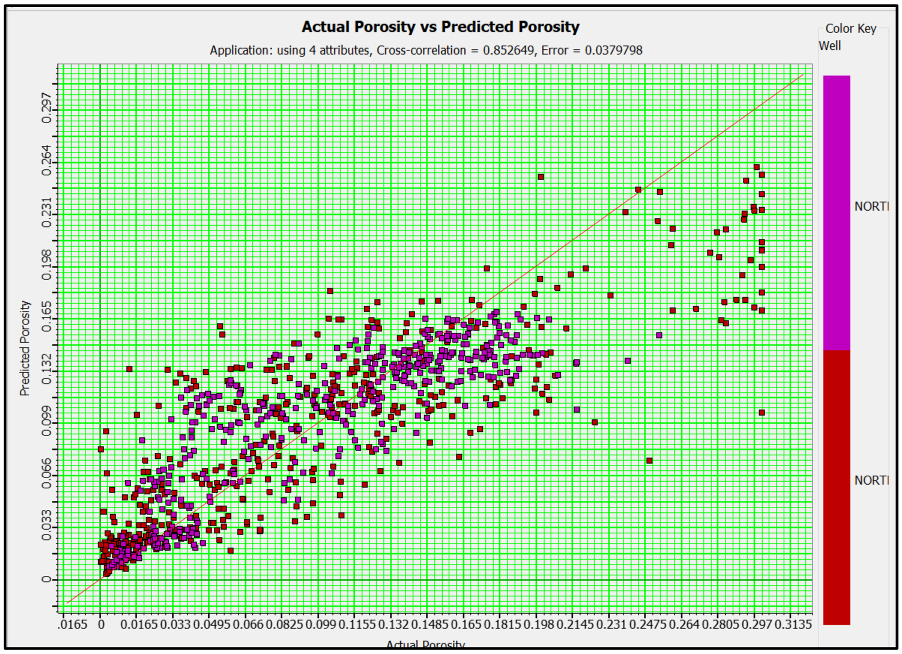


Fig. 4.9 porosity VS

Fig.4.9 shows the actual porosity vs the predicted porosity looks like. Which as we can see is very good prediction with a 0.85 correlation.

Porosity Volume Q.C

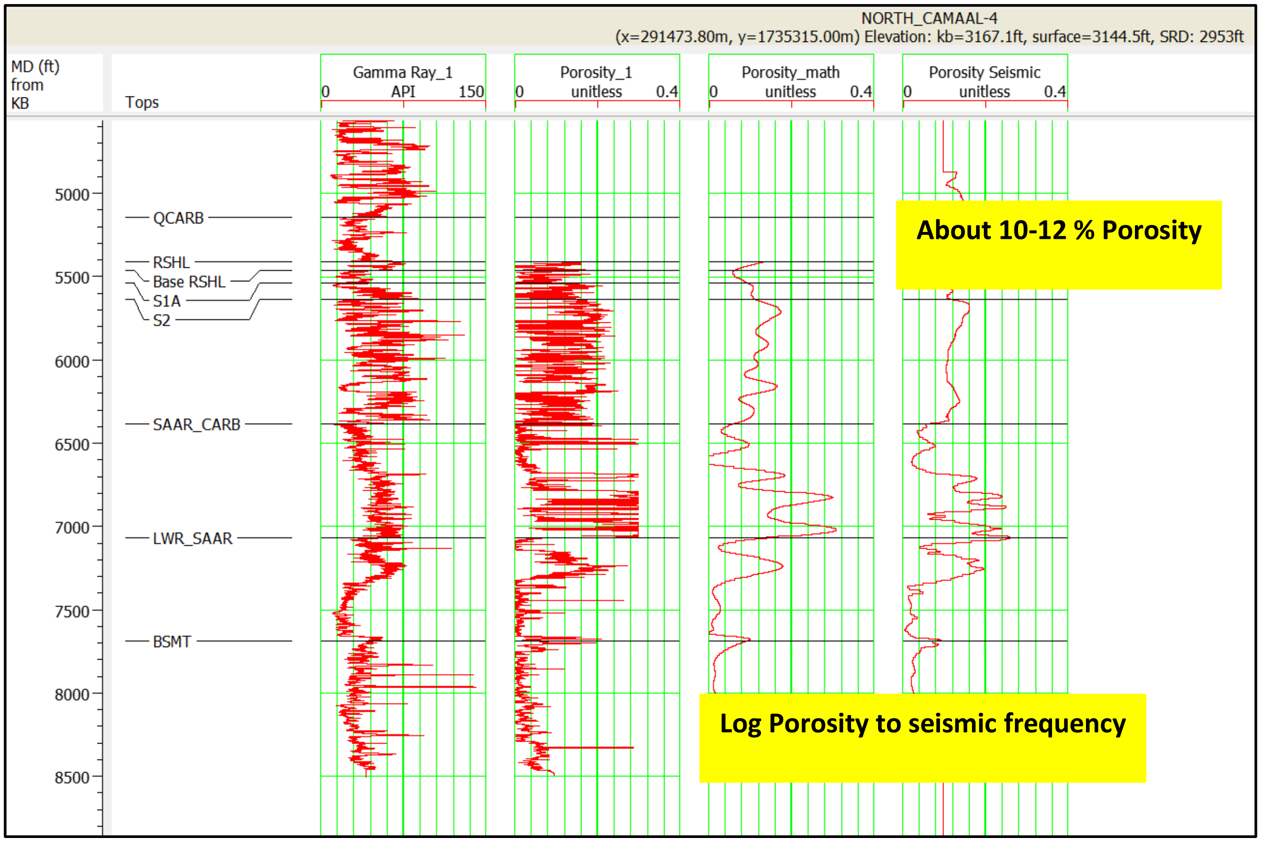
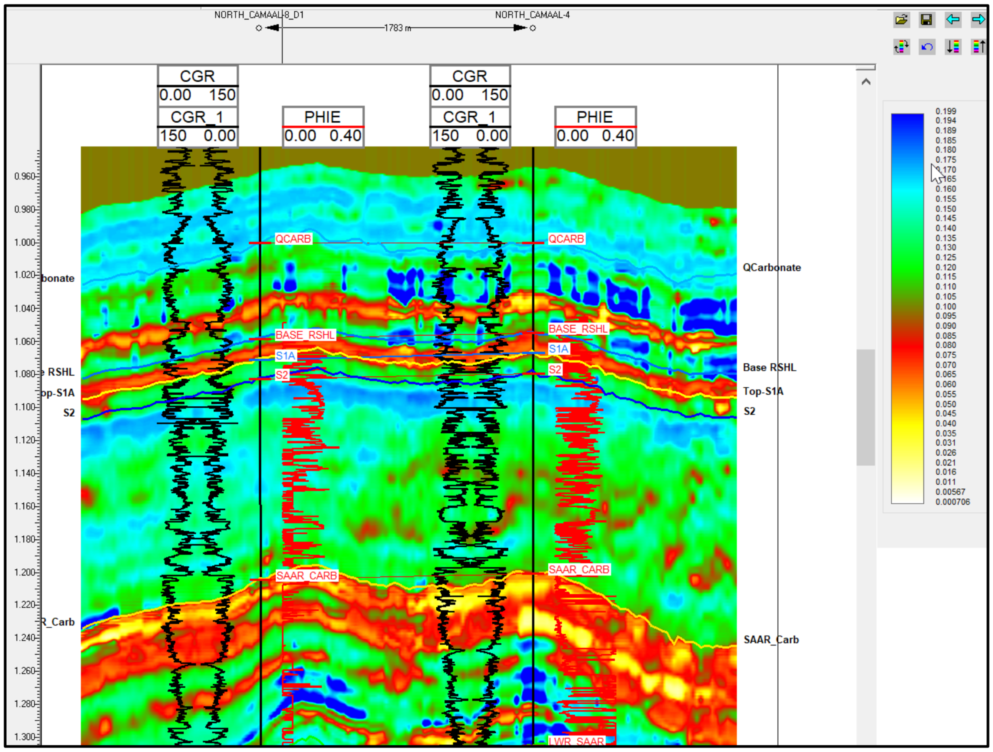


Fig. 4.10 Porosity Volume Q.C

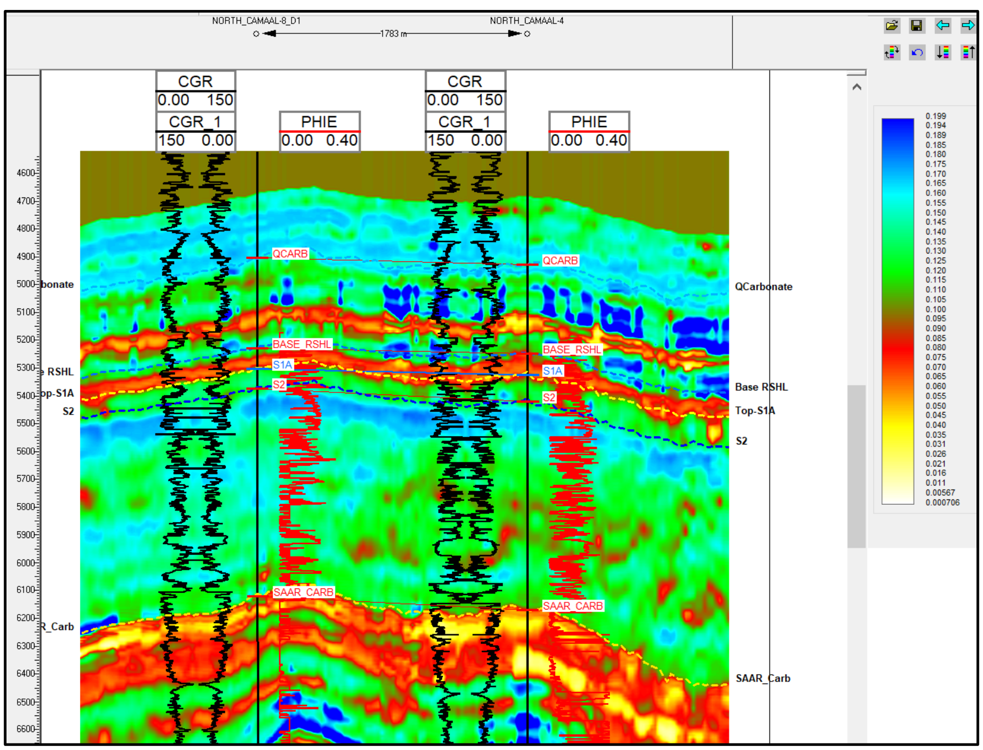
What we have here in fig. 4.10, is the gamma ray, then the porosity coming from the log, then you have two traces in the right. The first trace is the same log, which we filtered to low frequency. The reason behind that is because the porosity that comes from the seismic has a low frequency. So, if we were to compare the frequency of the seismic to the frequency of the log, the log is going to have a much higher frequency. In order for us to do any comparison between the two we first put them on the same domain of frequency which is about 60 Hz. What we can see in the S1A-S1 is a high deflection to the left and then a deflection to the right which means that there is very good correlation between what is predicted to be the porosity by the seismic, and what is the actual porosity is from the log.

Which is the same thing as the cross plot we discussed earlier.

Porosity Seismic Volume Depth

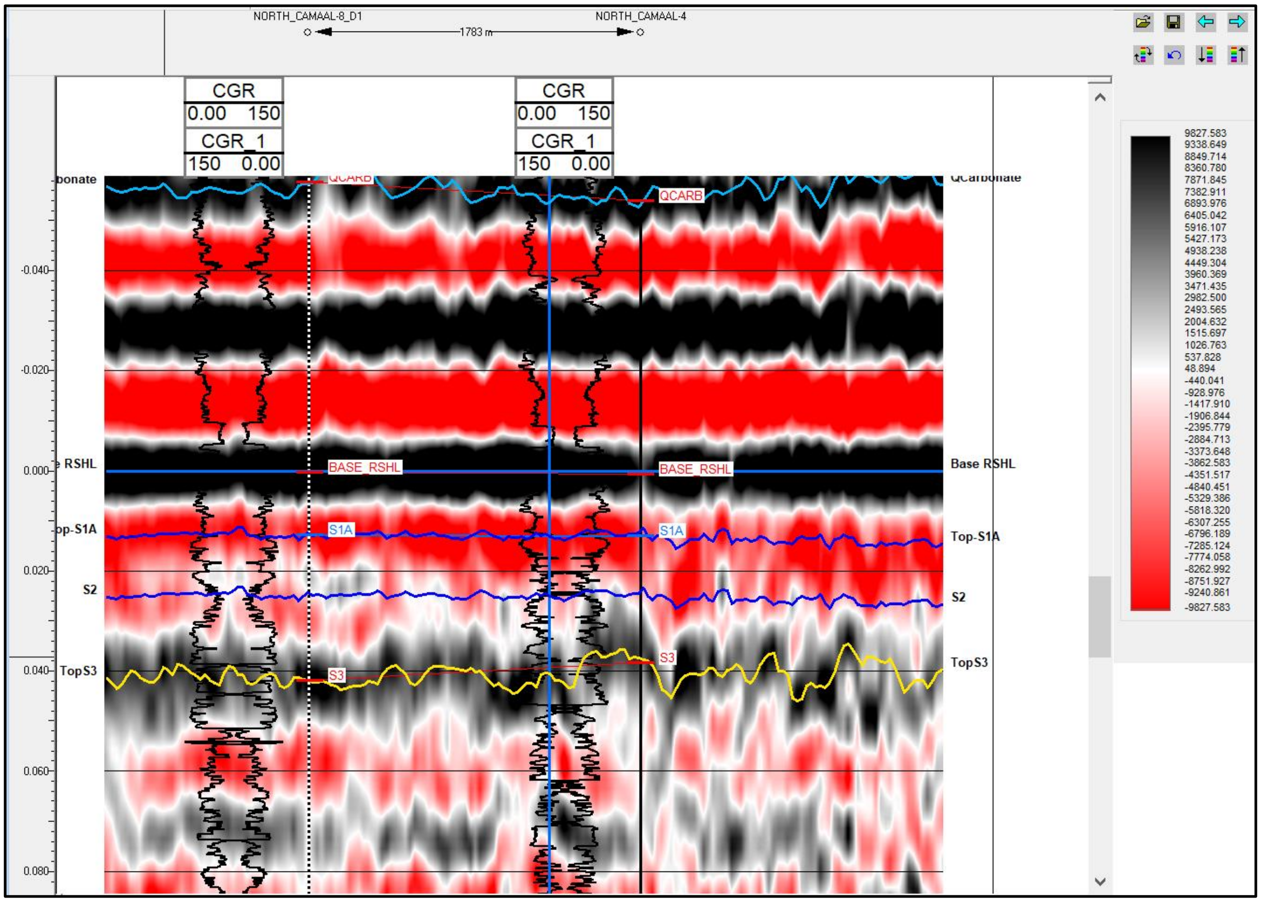


Porosity Seismic Volume Depth



Porosity Seismic map calibrated by wells

We mapped the seismic porosity for Top-S1A-Top-S3. Then we calibrated that with the data of the effective porosity from the petrophysical analysis we did in this study.



The porosities in the right are the porosity that was calculated from the petrophysical study of Qishn sandstone (S1A-S3) in NC4, and NC8.

Well Name	Well Numb	PHIE_ND.V
NORTH_CAMAAL-4		0.106
NORTH_CAMAAL-8_D1		0.128

We used this extra little bit of data to further improve our mapping which is an excellent.

Horizon Porosity Average Map

This horizon above in fig.4.11, shows the distribution of porosity in North Camaal field. As we can see from the horizon that porosity increases in the North-West region of the field. To see this more clearly, we converted this horizon into a grid with larger cells, we also smoothed the data in the process, which you can see below.

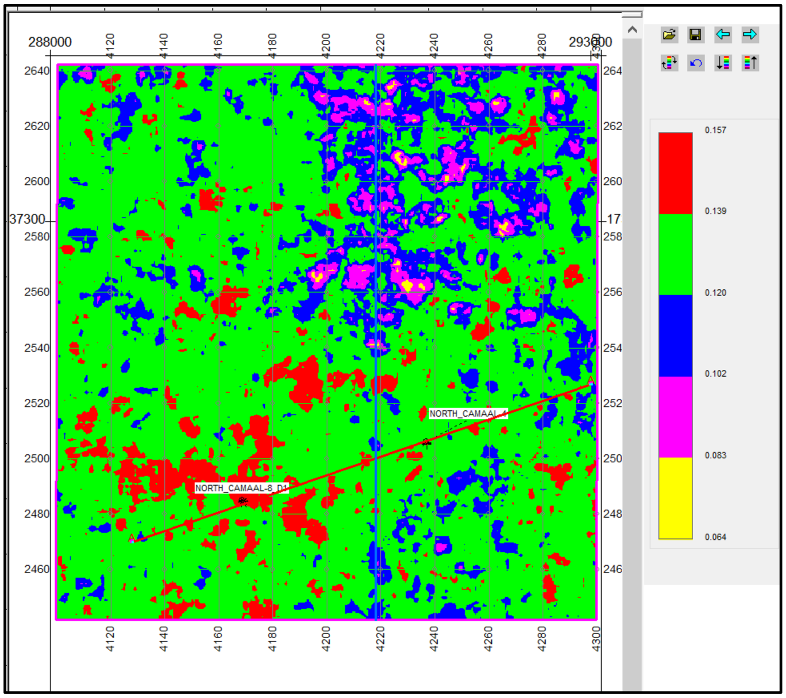


Fig. 4.11 Horizon Porosity Average Map

Average Porosity Grid

The cell size in the previous horizon in fig.4.11 was 10*10, but in fig.4.12 the cells are 200*200. The reason for doing that is we want to capture the trends. We then used this grid to create the final Porosity Map.

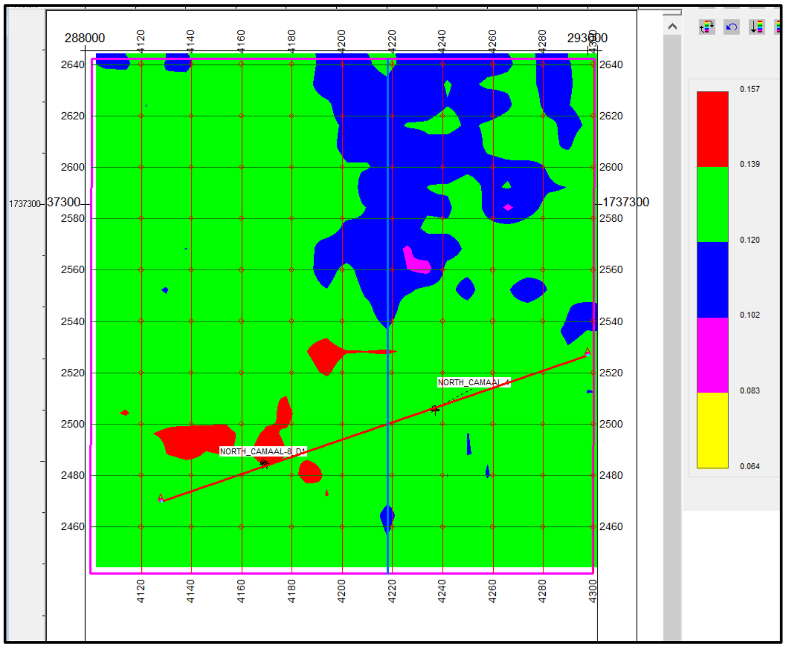
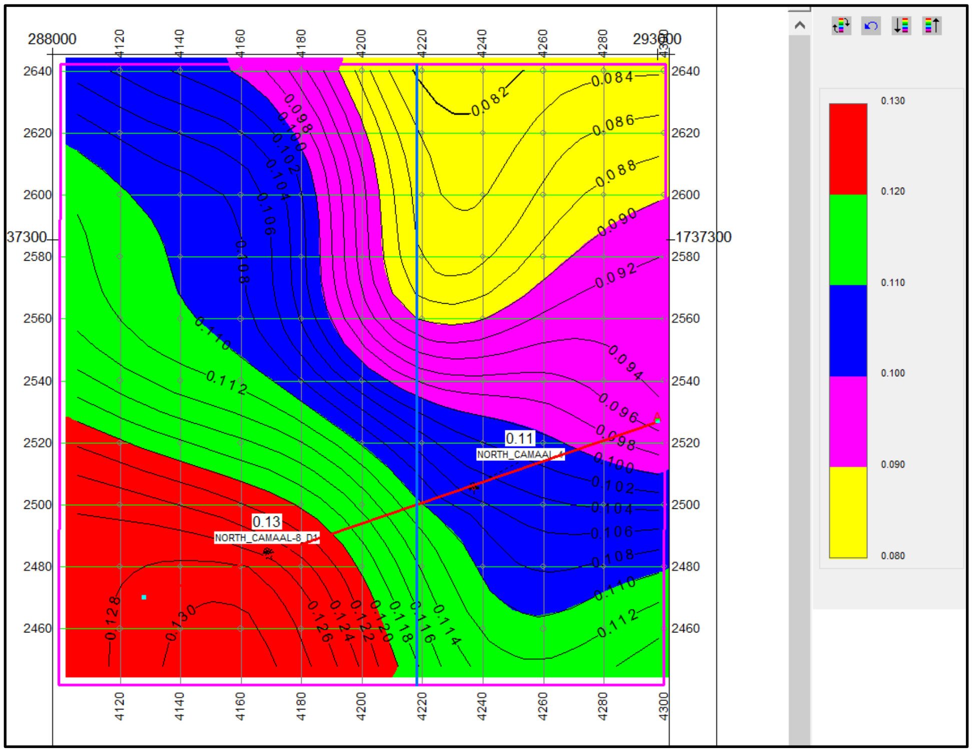


Fig. 4.12 Average Porosity Grid

Final Smooth Adjusted - Average Porosity map - TopS1A-Top S3



This porosity seismic map is calibrated by wells. We used the cross-interpolation process to increase the accuracy of the porosity seismic map, and as you can see from the contoured map in NC8 for example, the predicted porosity was 0.126 and the actual porosity was 0.13 which is the closest you can get with this method.

Permeability

Correlation of log (PHIE Porosity) and Core porosity

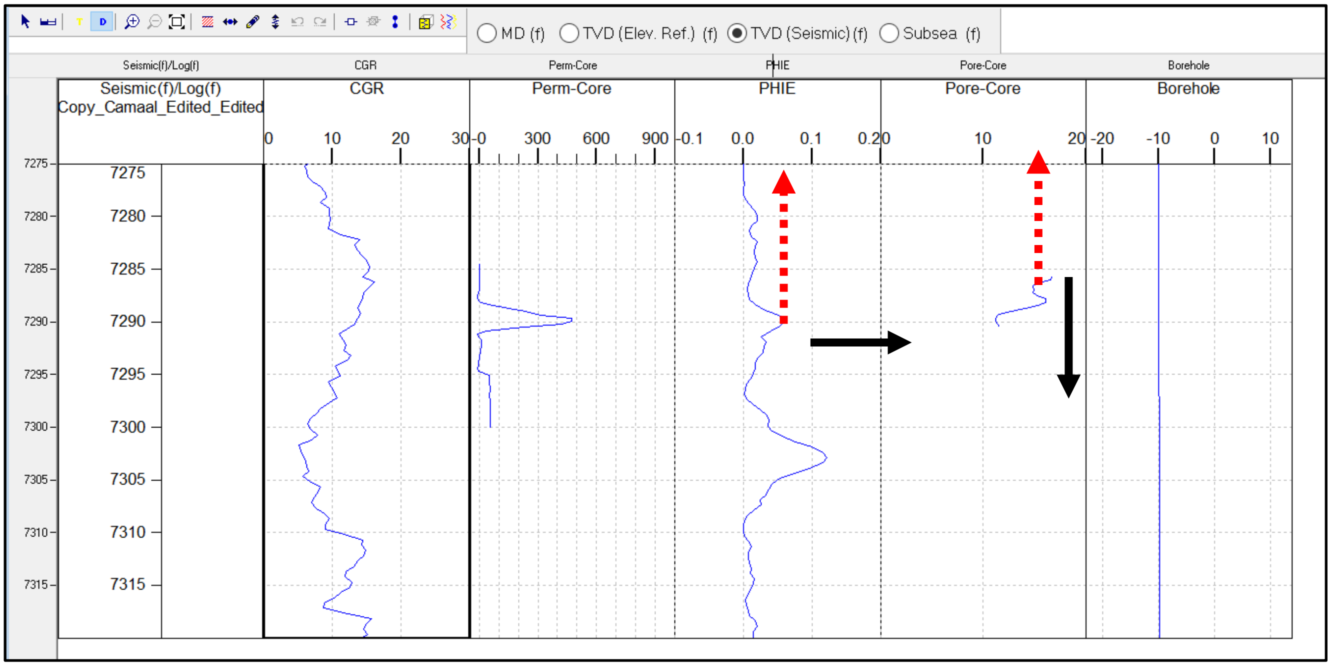


Fig. 4.13 Correlation of log (PHIE Porosity) and Core porosity

We converted the porosity core data sheet into a log format in order to be able to see it as shown in fig.4.13.

As you can see from fig.4.13 above, based on the log the effective porosity (PHIE) of the peak shown by the red arrow is about 6%. If we were to look at the point in the core porosity data (Pore-Core) shown also by the red arrow is 15% which is significantly more than the log porosity. What we realized to be the case is that there is about 2-3 feet difference between the log and the core data. So, first shifted the core data down by about 2 feet to match the log data which also resulted also in about 10% adjustment in the core data too.

Cross plot Core Porosity vs Permeability Camaal - 4

After we corrected the correction for the core porosity depth. We created the cross plot shown in fig.4.15 bellow.

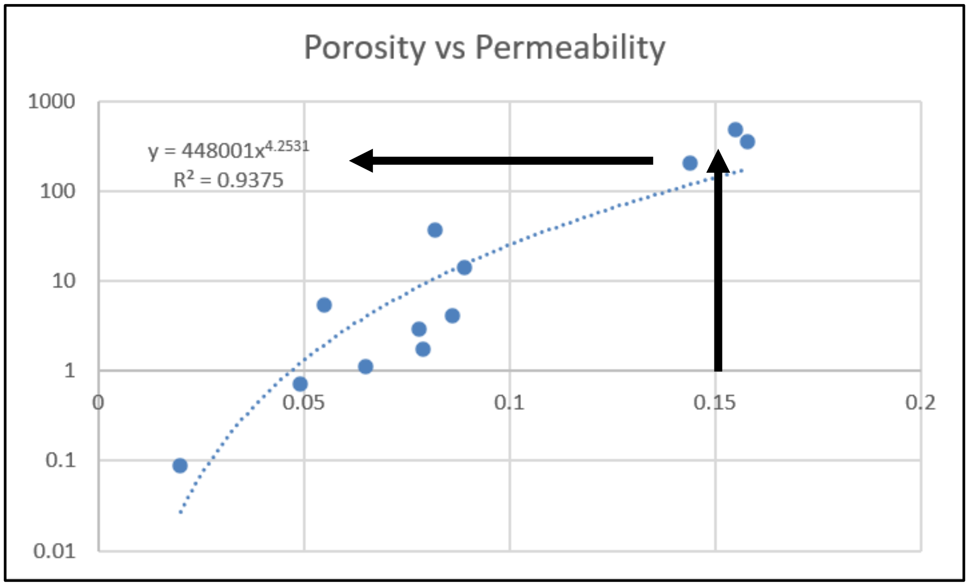


Fig. 4.15 Cross plot Core Porosity vs Permeability Camaal - 4

This correlation of 0.9375 which is very good correlation, shows that for every 15% porosity, we get 550 md in permeability.

This correlation was done using Camaal 4 well. Camaal 4D1 does not have Core Porosity values Camaal 8D1 does not have Core Porosity nor Core Permeability.

Permeability Seismic Volume

Once we created the cross plot and extracted the permeability function, we generated the permeability volume shown in fig.4.16 bellow: The peak shown by the arrow is the core permeability that was used to calibrate the data.

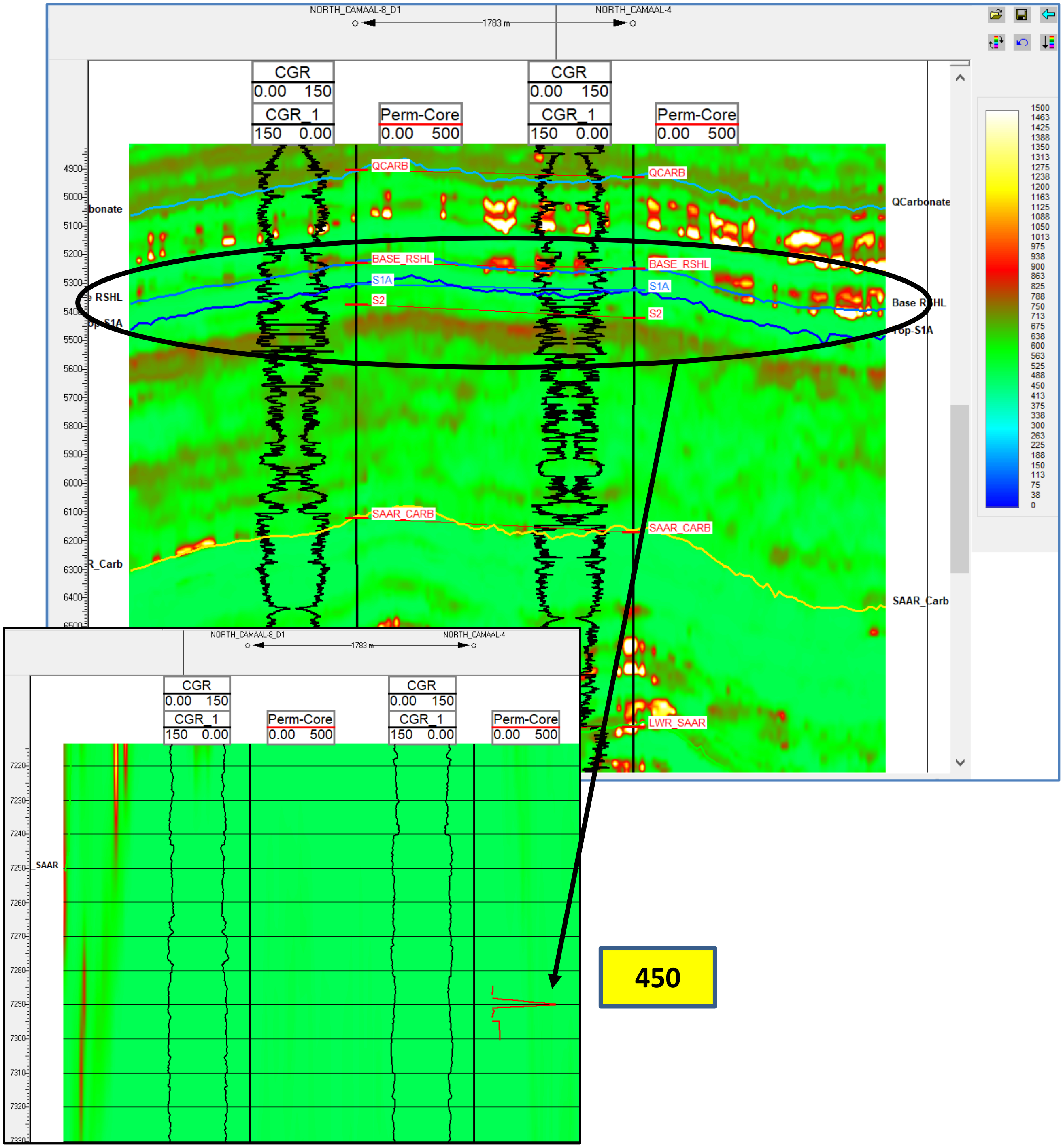


Fig. 4.16 Permeability Seismic Volume

Pore Pressure = Formation Pressure:

Because the formation pressure depends on velocity when it comes to the seismic calculations. We used the volume we did in the post-Stack conversion, and now instead of calculating the porosity we calculated the velocity.

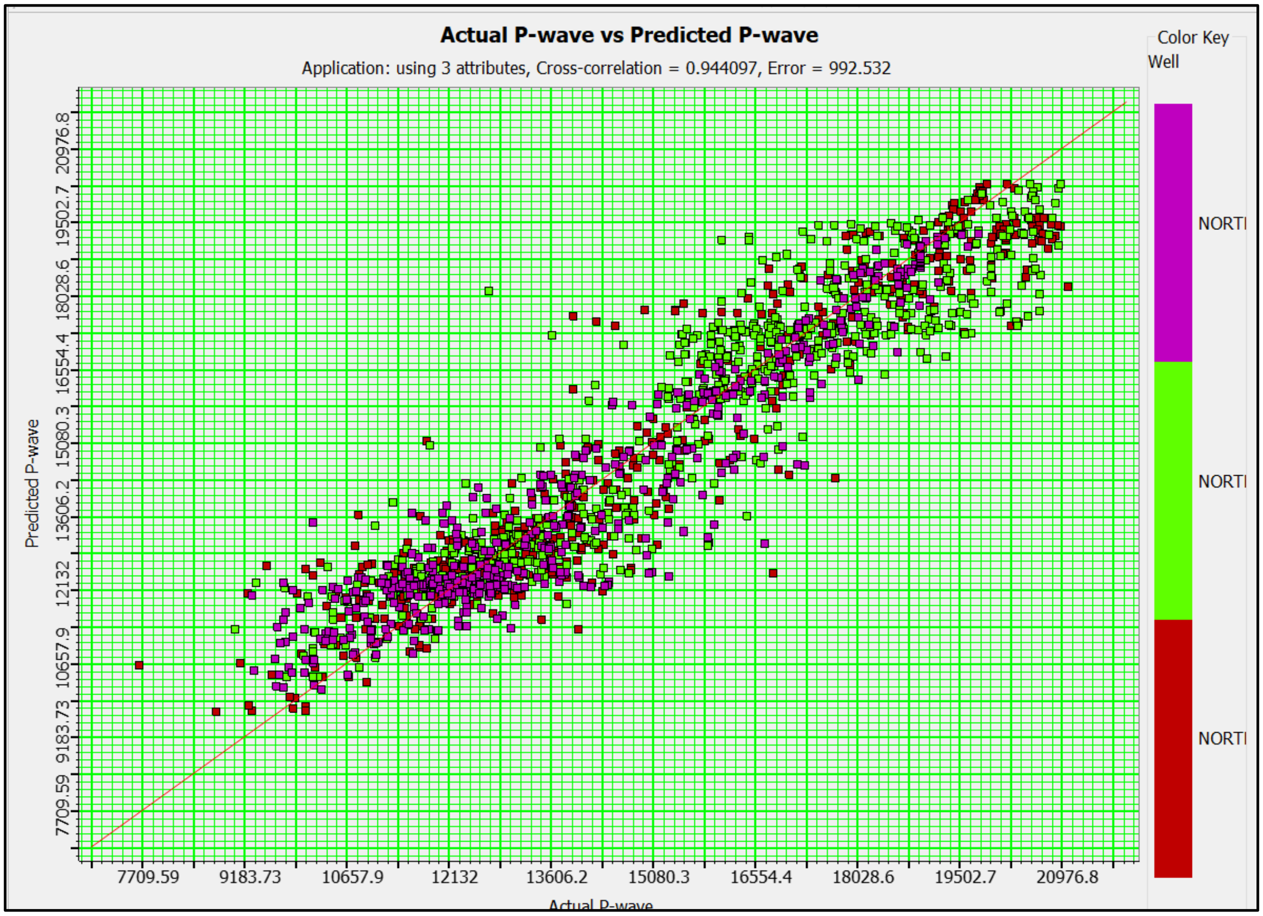


Fig. 4.17 Pore Pressure = Formation Pressure

The velocity model shown in fig.4.17 above, is used to calculated the effective stress.

DT and Check shots – Positive trend

The DT data is shown in fig.4.18, and in the next fig.4.19 shown the check shots.

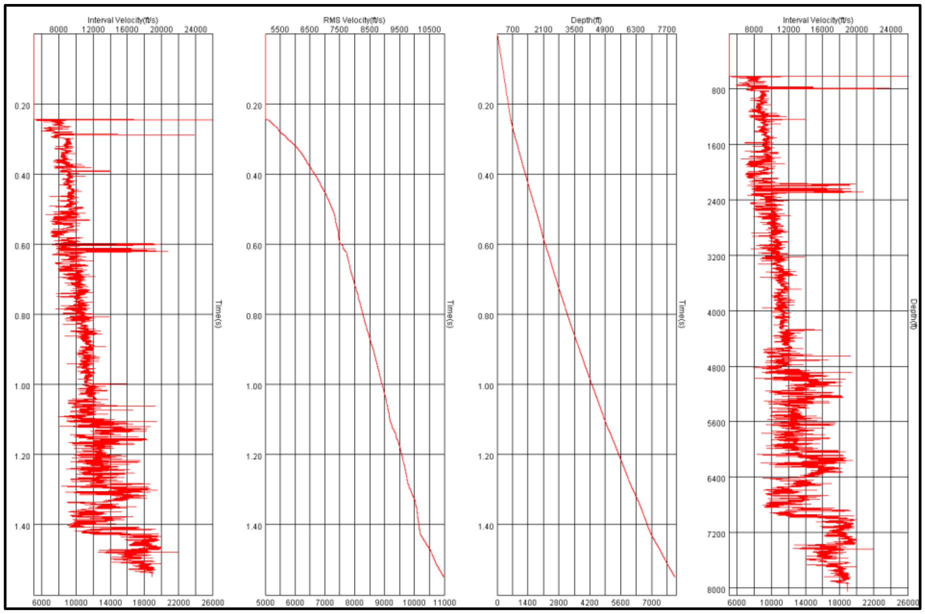


Fig. 4.17 DT

First, we corrected the DT data, put in all to the top and made sure that it has a positive trend because the pressure increases with depth unless you have overpressure. If you have an overpressure then you will have a declination to the left. The QC that was done in the DT, and Check shots was necessary before we use them to generated the pressure volume.

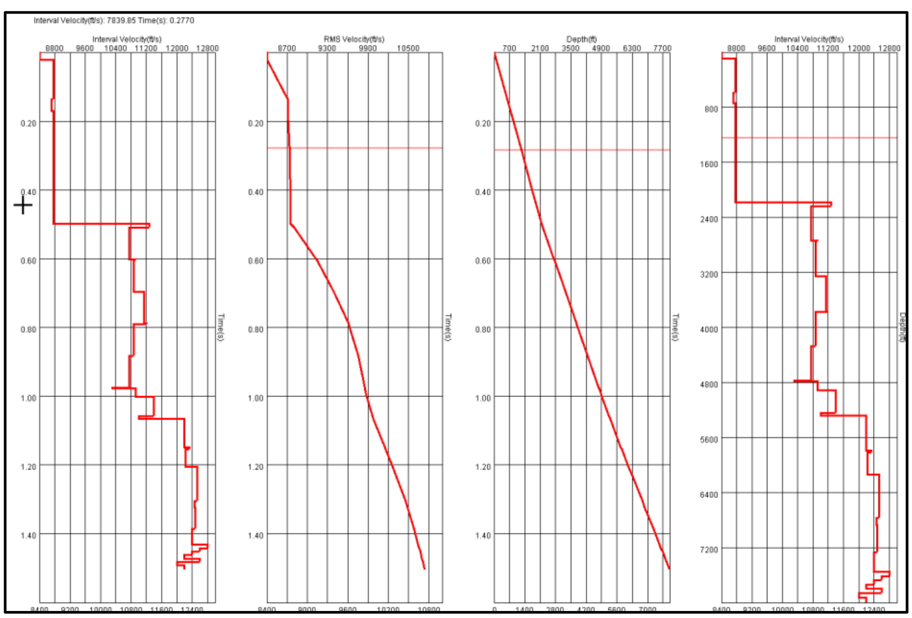
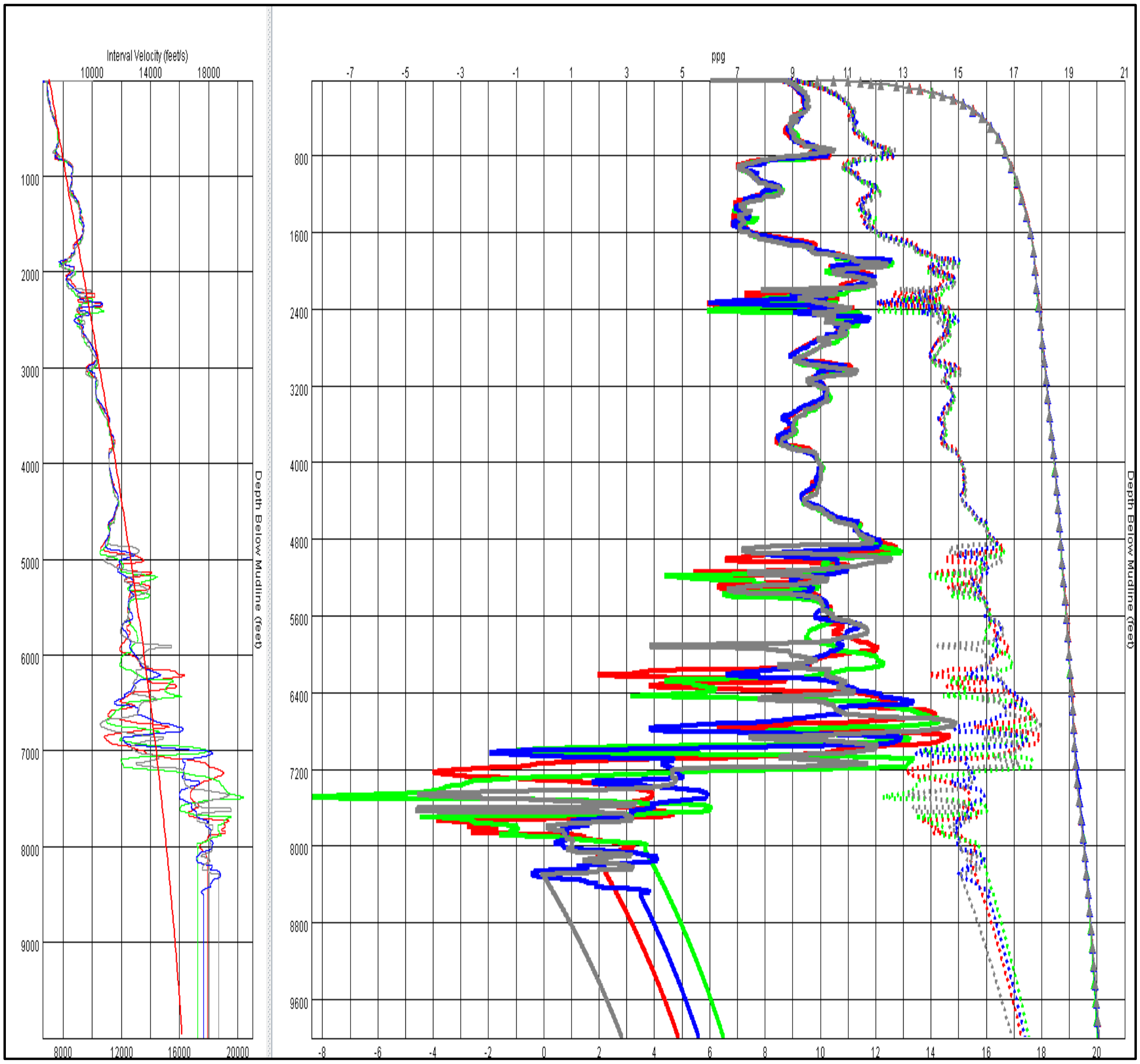


Fig. 4.18 Check shots

Pore Pressure Prediction



For this particular example, there are no overpressure zones (low interval velocity). Why. There are no organic shales (overpressure by the expansion of fluids) or rapid burial (like the Gulf of Mexico). A good exercise prior to pore pressure analysis is to examine the Vshale log. In theory, you should have more than 35 % shale and should be organic to be affected by overpressure. Anything below 35 % it will behave as hydrostatic pressure.

Pore Pressure prediction Volume

The following volume in fig.4.19 represents the pore pressure prediction.

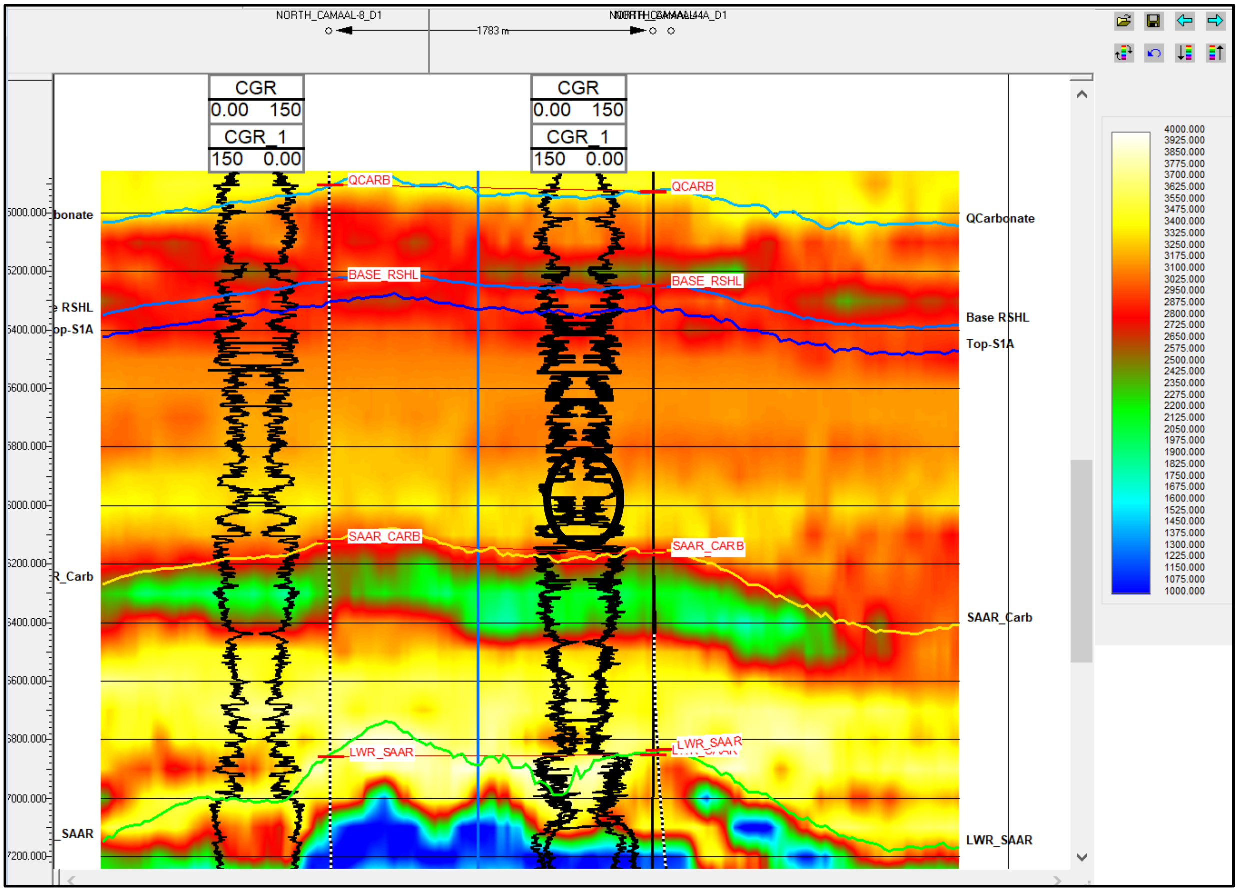


Fig. 4.19 Pore Pressure prediction Volume

One thing that we can see from the volume above is that there is a transition zone bellow SAAR_Carb showing values of under-pressure.

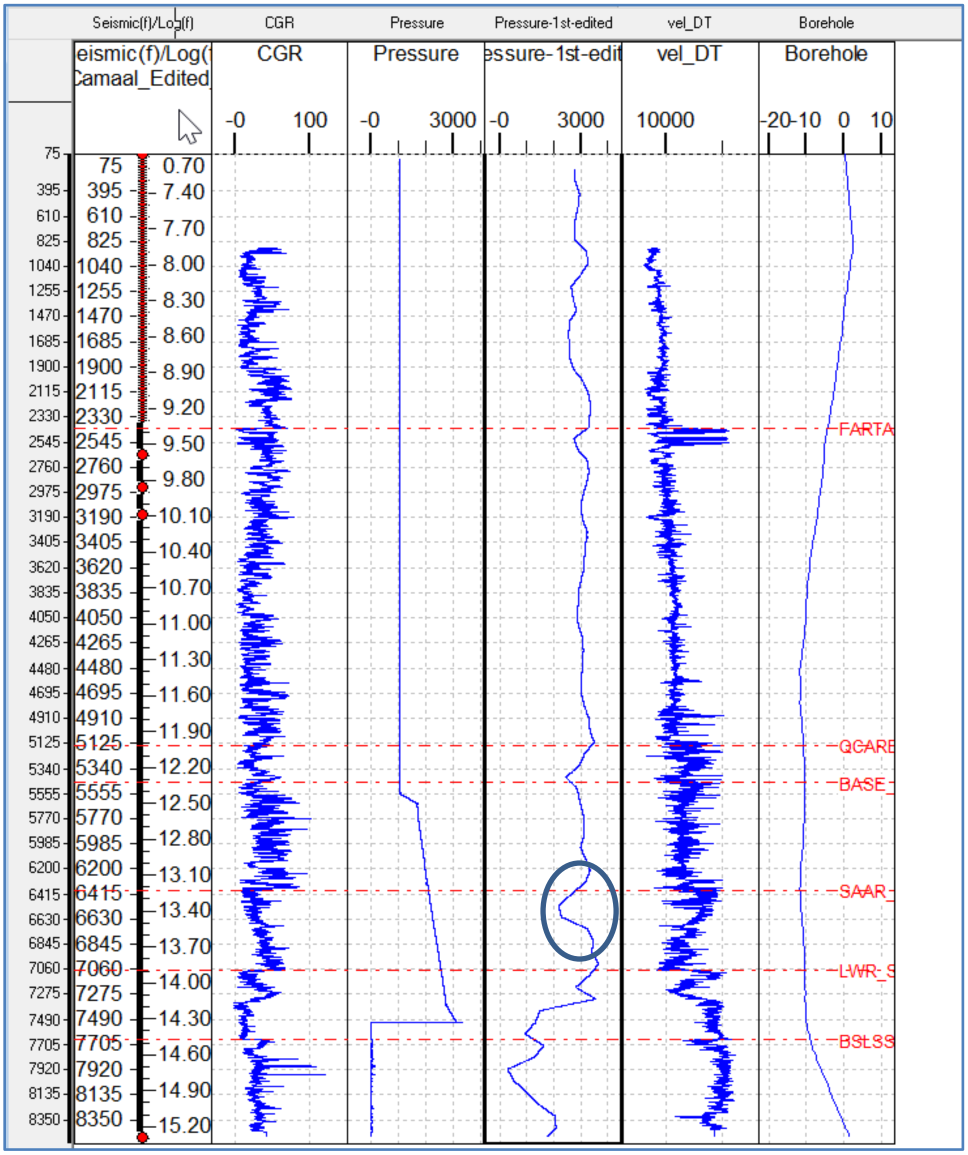


Fig. 4.20 RFT Vs. Seismic

We don't see in the RFT data the same area of under-pressure in fig.4.20. So, the seismic is telling us that there is an under-pressure zone bellow SAAR-Carb circled by blue, but it's not shown in the RFT data. We can also see the under-pressure in at the base of the sand which is Qishn.

This strikes a question, why we don't see the same under-pressure in the log data? It also has high resistivity from the log which is an indication of hydrocarbon. It has high density which means it's a tight formation, which looks like a potential unconventional reservoir like the case of Bernt field in US, Texas. We encourage further study in this area from the Geomechanically point of view.

4.2 Petrophysical Analysis Findings:

Different qualitative and quantitative well logging analyses for two wells are carried out over Qishn Clastic reservoir to identify its petrophysical properties. A number of cross plotting are used to give some insights about reservoir lithology, shale parameters. Determination of the lithological content is first step to proceed for further reservoir properties estimation. Porosity mostly used in marking the reservoir intervals from the gross interval and it is estimated using N-D log. Rw was estimated from the Pickeet Fig.(4.21) and further employed in calculating water saturation that is used in marking the net pay from the reservoir intervals. Indonesian equation in Techlog software is used to calculate the water saturation.

In this study for defining the reservoir interval, the effective porosity is greater than 10% and volume of shale less than 35% are used. For net pay or producible zones marking, water saturation less than 50% are taken.

From the wellsite geologist report for North Camaal 4, it was stated that Upper Qishn Clastic formation is mainly Sand and Sandstone interbedded with Shale and minor Limestone at places. (Unpublished Report, 2002). Core description data is used at some intervals to verify the findings.

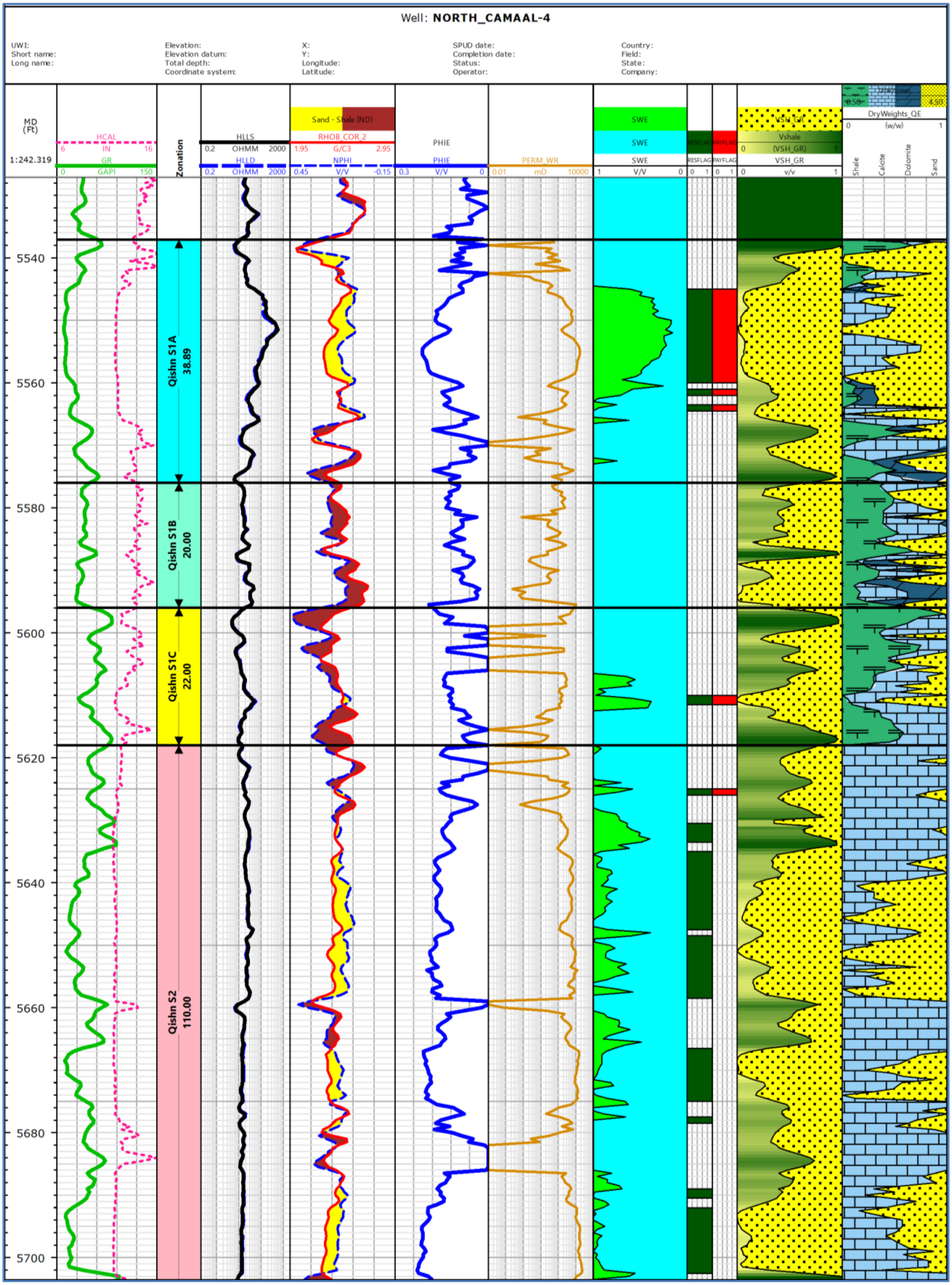
4.2.1 North Camaal -4 well :

Three main reservoir units were identified in the North Camaal -4 log namely S1A Sands, S1C Sands and S2 Sands are present. These three sand units are of Cretaceous age and interbedded with shale. The S1A unit of Cretaceous age is the main sandstone reservoir unit in the North Camaal -4 with thickness up to 39 ft encounted in NC-4 well log, which is interbedded with shale. S1A has oil bearing zone (narrow cross over) located in the middle S1A unit (554x ot 55xx ft) ((Fig. 4.22).

North Camaal 4 - Petrophysical Properties

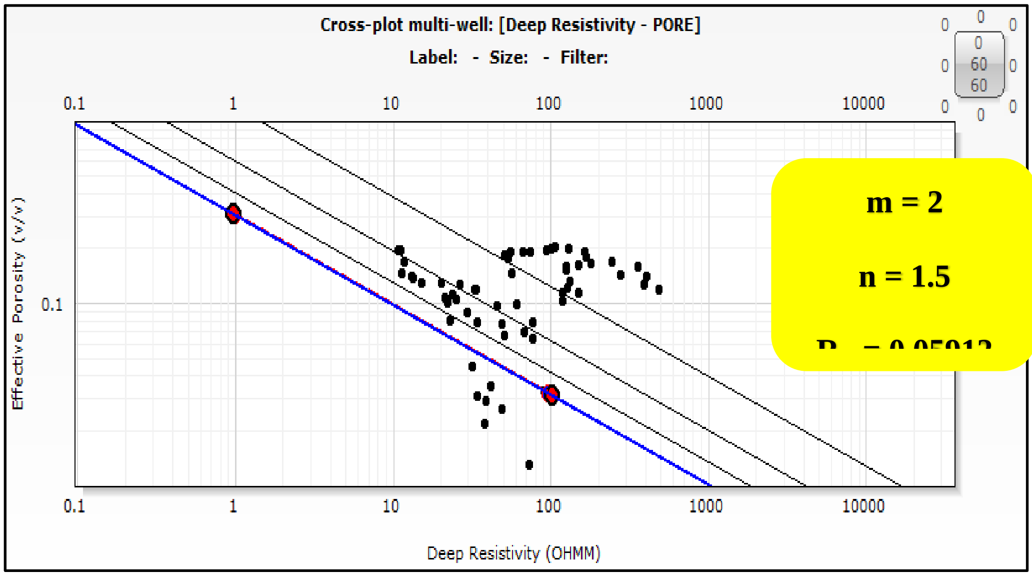
Zones	Top	Bottom	Gross	Net Reservoir	Net Pay	Av_Shale Volume	Av_ Porosity	Av_ Water Saturation
	ft	ft	ft	ft	ft			
S1A	5537	5576	39	23.5	17	0.13	0.14	0.4
S1B	5576	5596	20	13	0	0.25	0.11	1
S1C	5596	5618	22	4	1.5	0.17	0.12	0.6
S2	5618	5728	110	61	0.5	0.19	0.16	0.9
S3	5728	5765	37	21.5	0	0.235	0.194	1.0

Table 3 summary North Camaal 4 - Petrophysical Properties


Well: NORTH_CAMAAL-4
UWI:
Short name:
Long name:
Elevation:
Elevation datum:
Total depth:
Coordinate system:
X:
Y:
Longitude:
Latitude:
SPUD date:
Completion date:
Status:
Operator:
Country:
Field:
State:
Company:
MD (Ft)
1:242.319
HCAL
6 IN 16
GR
0 GAPI 150
Zonation
HLLS
0.2 OHMM 2000
HLLD
0.2 OHMM 2000
Sand - Shale (ND)
RHOB_COR_2
1.95 G/C3 2.95
NPHI
0.45 V/V -0.15
PHIE
PHIE
0.3 V/V 0
PERM_WR
0.01 mD 10000
SWE
SWE
SWE
1 V/V 0
RESFLAG
PAYFLAG
RESFLAG 0 1
PAYFLAG 0 1
VSH_GR
Vshale
0 (VSH_GR) 1
VSH_GR
0 v/v 1
DryWeights_QE
0 (w/w) 1
Shale
Calcite
Dolomite
Sand
5540
5560
5580
5600
5620
5640
5660
5680
5700
Qishn S1A
38.89
Qishn S1B
20.00
Qishn S1C
22.00
Qishn S2
110.00

Pickeet Plot, Rw:

m = cementation factor n = saturation exponent



4.2.1.1 S1A

Petrophysical Description:

Based on petrophysical analysis table 4.1, for NC4 S1A, has 23.5 ft as net reservoir and net pay is about 17 ft with both porosity and water saturation as 14%, 40% respectively.it is the major reservoir unit in the Qishn sandstone.

Lithology:

Based on Neutron-Density cross-plot figure 4.23 for NC4 (North Camaal) S1A, the formation is dominantly sandstone and some Limestone and this is compatible with well log interpretation fig.(4.23).

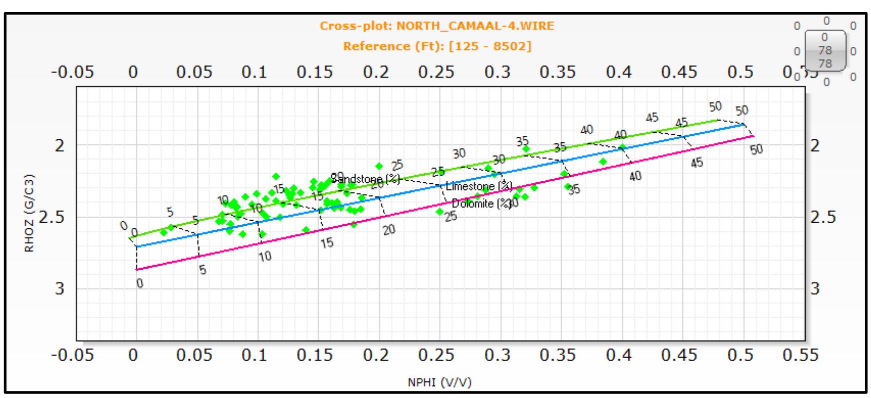


Figure 4- 23 North Camaal 4 S1A – ND Cross-plot

A good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description “Sandstone is dominantly composed of loose quartz grains that are very fine to medium and rarely coarse to very coarse grained. The grains are sub rounded to rounded at the top and become sub angular with depth, sub spherical and very poorly sorted with a fair amount of pyrite. (Unpublished Report, 2002)

Less than 10% of Sandstone is consolidated and is translucent and off white in color, moderately hard, fairly cemented with calcareous cement and show poor to fair intergranular porosity and no oil shows.

Limestone is off white, dirty white and buff colored Mudstone that is moderately hard, soft and chalky in places and cryptocrystalline. It has abundant fine to medium grained Sand, dark gray pellets and occasional dark green pellets in a muddy matrix, disseminated carbonaceous matter and occasional pyrite. There is no visible porosity or oil shows. (Unpublished Report, 2002)

A core description data is also used in the fig.4.24 bellow,

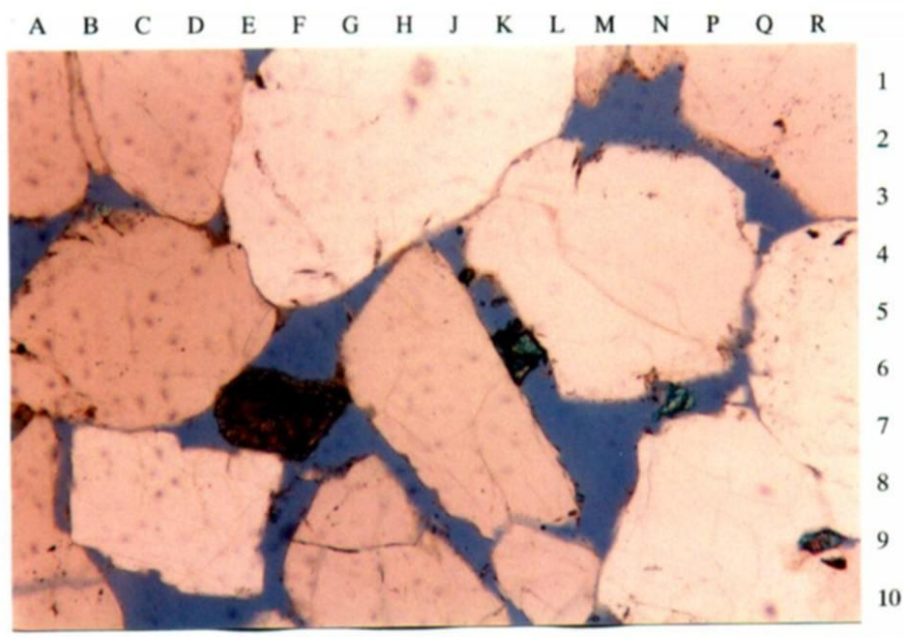


Plate 1 North Camaal-4, 5547ft ?Qishn Clastics. Porous quartz arenite with minor ferroan calcite (E7) and ferroan dolomite (K6, N7) cements. PPL. Field of view 1.44mm.

Fig. 4.24 plate I north cammal – 4 , 5547ft

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume figure 4.25, shale content in S1A is about 13% and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

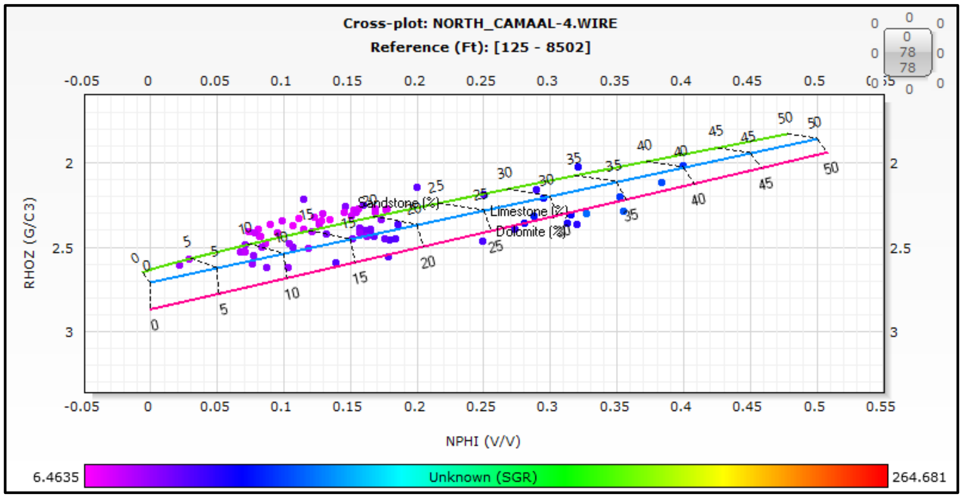


Figure 4-255 North Camaal 4 S1A – 3D Cross-plot

4.2.1.2 S1B

Petrophysical Description:

Based on petrophysical analysis table 4.1, for NC4 S1B, has 13 ft as net reservoir and net pay is about 0 ft with both porosity and saturation as 11%, 1% respectively. No hydrocarbon content is detected at S1B unit at this well.

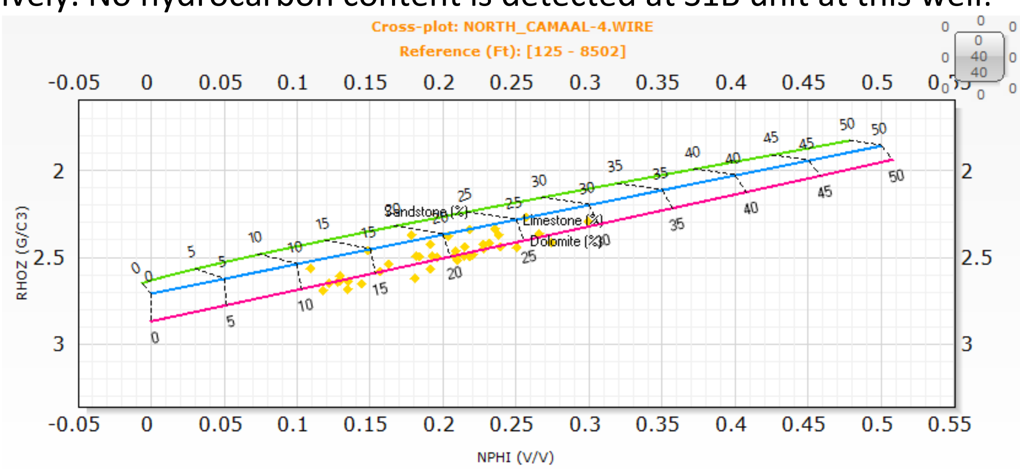


Figure 4-266 North Camaal 4 S1B – ND Cross-plot

Lithology:

Based on Neutron-Density cross-plot figure 4.27 for NC4 (North Camaal) S1B, the formation is dominantly calcareous sandstone with sandy limestone and minor shale.

A good matching is recognized between the results of log interpretation and cross plot above but not with the following mudlogging description "Sandstone is white, off white, light gray and occasionally very light brown in color, friable to moderately hard, rarely very hard, fine grained and locally very fine to medium grained. The grains are sub angular to sub rounded, moderately sorted and fairly cemented with calcareous cement and at places siliceous cement. It has an argillaceous matrix in places with glauconite, fair to poor intergranular porosity and poor oil shows. (Unpublished Report, 2002)

Shale is light gray, olive gray and occasionally reddish brown in color, moderately hard, sub fissile to fissile, silty in places and calcareous. It has also disseminated carbonaceous matter. (Unpublished Report, 2002)

Limestone is highly sandy, light gray, dirty white and occasionally off white in color, moderately hard to hard and cryptocrystalline. It has abundant fine to medium grained Sand along with pyrite, dark gray and dark green pellets and occasional glauconite. It has none to poor visible porosity and no oil shows. (Unpublished Report, 2002)"

So, a new cross-plot was used to verify the lithology which is the N-S lithology cross-plot shown in fig. 4.28 bellow,

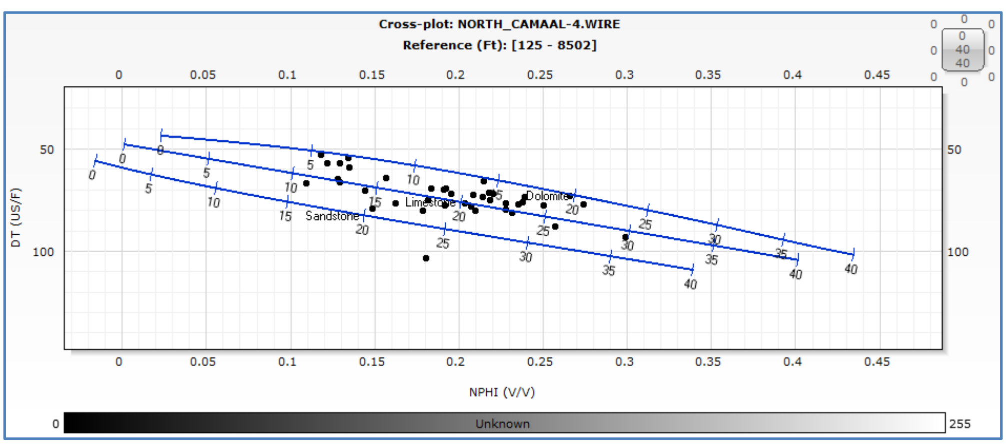


Fig. 4.28 cross-plot

As we can see from fig.4.28 above, the Neutron-Sonic lithology plot is showing a verification that S1B in NC4 is dominated by Dolomite and Limestone.

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume figure 4.4 bellow, shale content in S1B is about 0.25 and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

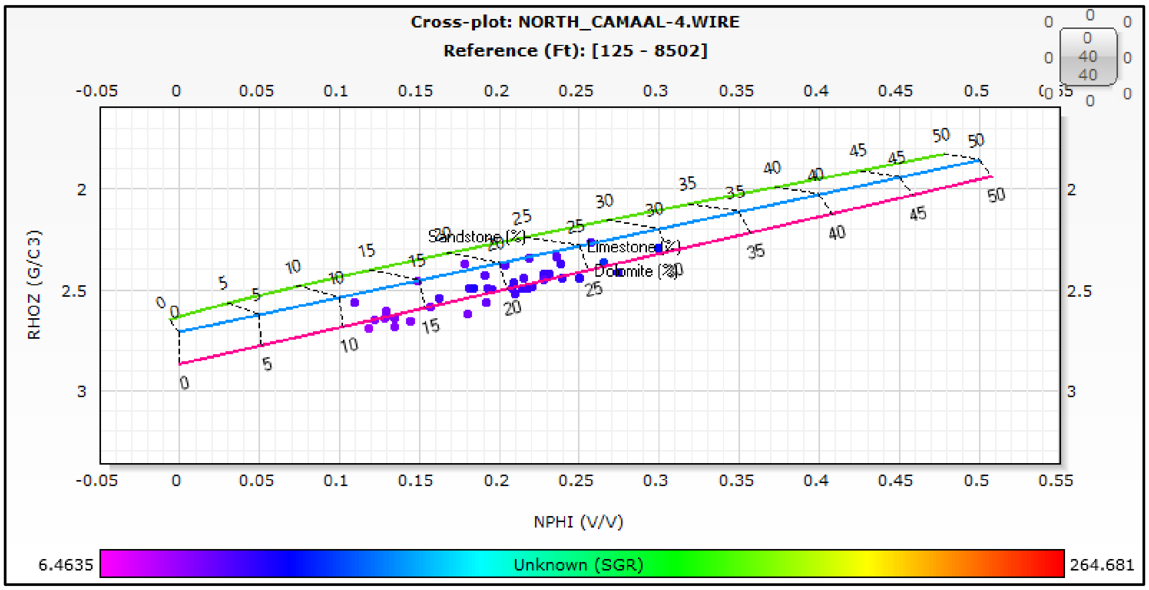


Figure4- 27 North Camaal 4 S1B – 3D Cross-plot

4.2.1.3 S1C

Petrophysical Description:

Based on petrophysical analysis table 4.1, for NC4 S1C, has 4 ft as net reservoir and net pay is about 1.5 ft with both porosity and saturation as 12 %, 60% respectively.

Lithology:

Based on Neutron-Density cross-plot figure 4.29 for NC4 (North Camaal) S1C, the formation is predominantly sandstone with minor shale, and some limestone and this is compatible with well log interpretation fig.(4.29).

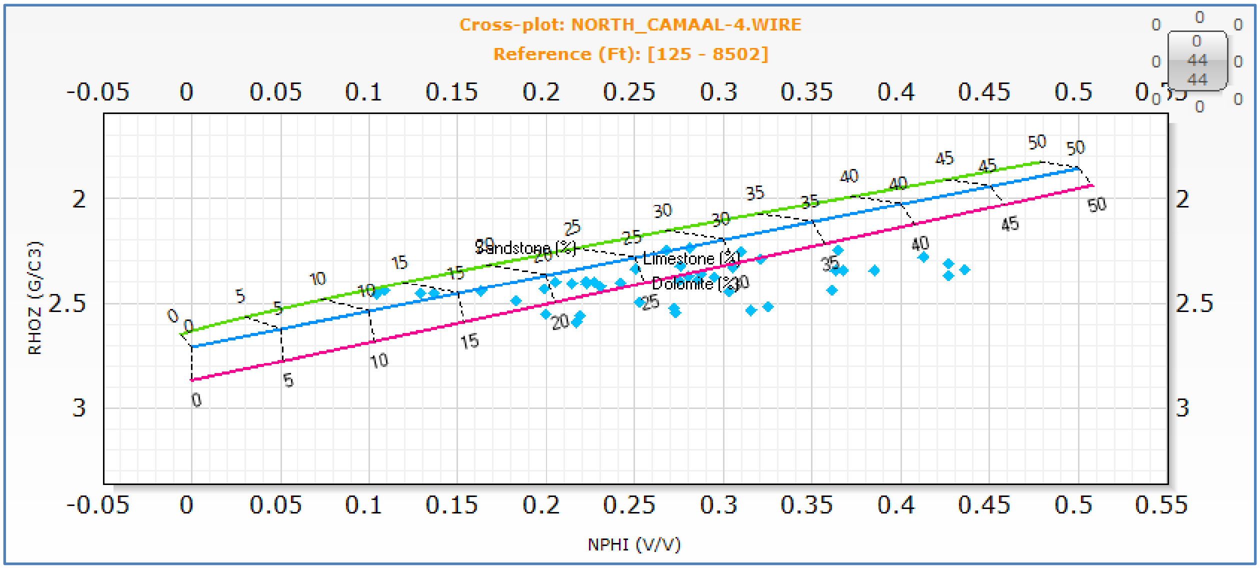


Figure4-28 North Camaal 4 S1C – ND Cross-plot

good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description “Sandstone is dominantly loose quartz grains that are very fine to medium grained at the top and very fine to fine grained towards the base, sub angular to sub rounded that becomes rounded with depth, sub spherical to spherical and moderately sorted. (Unpublished Report, 2002)

10 to 20% of Sandstone is consolidated and is translucent, off white and light brown in color and friable to moderately hard. It is moderately cemented with slightly calcareous cement, has an argillaceous matrix and show fair intergranular porosity and traces of dead oil. (Unpublished Report, 2002)

Shale is light gray, light olive green and occasionally reddish brown in color, moderately hard, sub fissile to fissile, silty in places, has disseminated carbonaceous matter and is calcareous. (Unpublished Report, 2002)

Limestone is Mudstone that is off white, light gray and moderately hard with abundant Sand grains and black pellets and occasional pyrite and glauconite. It has poor visible porosity and no oil shows. (Unpublished Report, 2002)

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume figure 4.30 bellow, shale content in S1C is about 17% and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

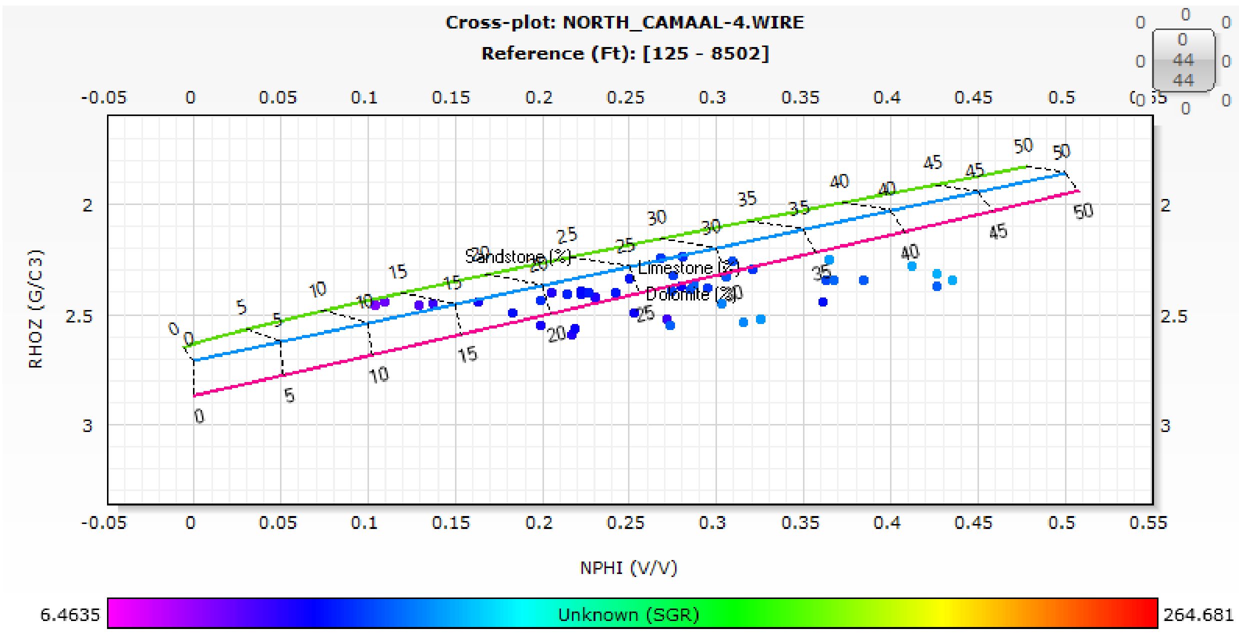


Figure 4-29 North Camaal 4 S1C – 3D Cross-plot

4.2.1.4 S2

Petrophysical Description:

Based on petrophysical analysis table 4.1, for NC4 S2, has 61 ft as net reservoir. The net pay is about 0.5 ft with both porosity and saturation as 16 %, 90% respectively.

Lithology:

Based on Neutron-Density cross-plot figure 4.31 for NC4 (North Camaal) S2, the formation is dominantly sandstone and interbedded with minor shale and this is compatible with well log interpretation fig.(4.31)..

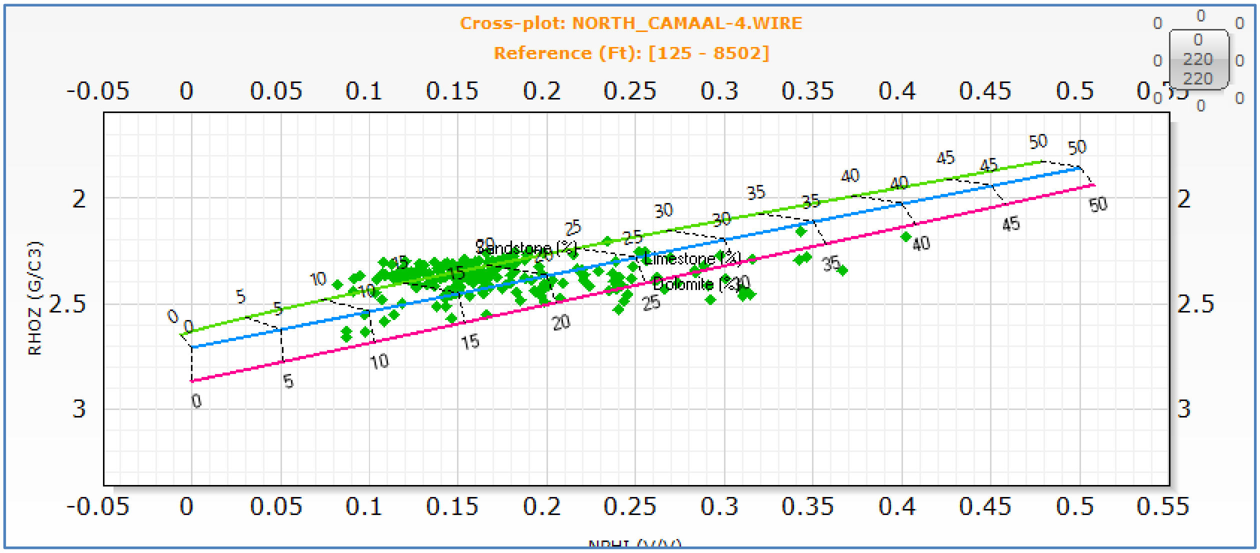


Figure4- 30 North Camaal 4 S2 – ND Cross-plot

good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description “Sandstone is dominantly made of loose quartz grains that are very fine to medium at the top and becomes medium to coarse grained with depth, sub angular to sub rounded and becomes more rounded with depth and poorly sorted. (Unpublished Report, 2002)

20 to 30% of Sandstone is consolidated and is off white, very light brown and rarely olive green in color. It is friable to moderately hard, sub angular to sub rounded, fairly well cemented with slightly calcareous cement and has an argillaceous matrix in places. It has fair intergranular porosity and significant dead oil stains. (Unpublished Report, 2002)

Shale is dominantly light olive green in color at the top and also light gray and occasional reddish brown in the rest of the formation. It is firm to moderately hard, sub fissile to fissile, occasionally sub blocky, has disseminated pyrite and glauconite in places and non-calcareous. Reddish brown Claystone is sub blocky, silty and slightly calcareous. (Unpublished Report, 2002)”

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume figure 4.32 bellow, shale content in S2 is about 19% and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

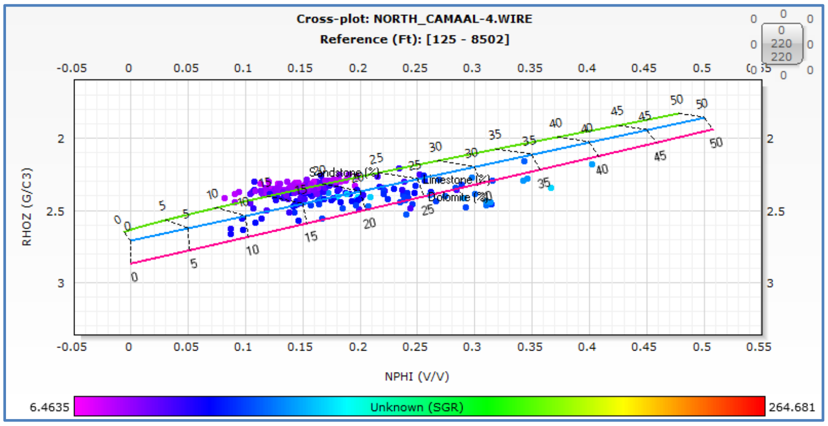


Figure 4-31 North Camaal 4 S2 – 3D Cross-plot

4.2.1.5 S3

Petrophysical Description:

Based on petrophysical analysis table 4.1, for NC4 S3, has 21.5 ft as net reservoir. The net pay is about 0 ft with both porosity and saturation as 19.4 %, 1% respectively. S3 is mainly water bearing

Lithology:

Based on Neutron-Density cross-plot figure 4.33 for NC4 (North Camaal) S3, the formation is dominantly sandstone with minor shale and this is compatible with well log interpretation fig.(4.33)..

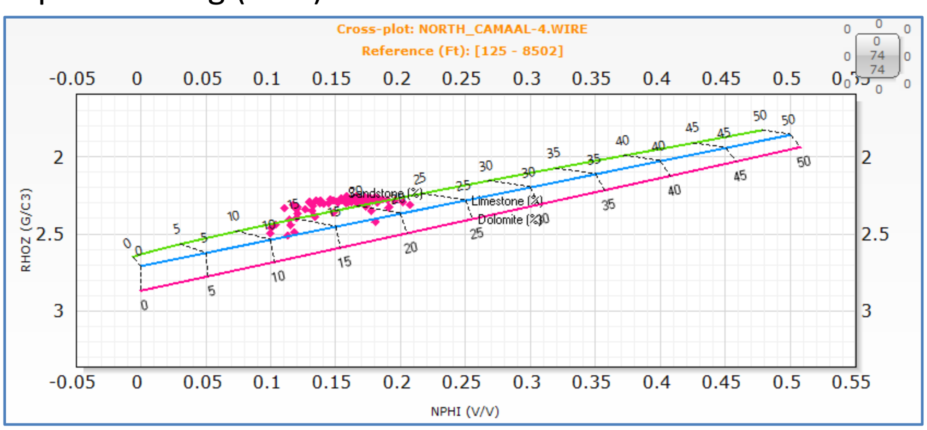


Figure 4-32 North Camaal 4 S3 – ND Cross-plot

good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description “Sandstone is dominantly loose quartz that is transparent to translucent with rare yellowish orange and reddish orange stains. It is fine to medium grained and occasionally coarse grained at the top and becomes coarser with depth. The grains are sub angular to sub rounded, locally rounded and spherical, very poorly sorted and has occasional pyrite. Traces of slightly calcareous cement are seen in places and there are no oil shows. (Unpublished Report, 2002)

Shale is light brown, light olive green, light brownish gray, light purple and in places reddish brown in color, firm to moderately hard, sub blocky to sub fissile and locally fissile. It has traces disseminated pyrite and is occasionally feebly calcareous. (Unpublished Report, 2002)”

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume figure 4.34 bellow, shale content in S3 is about 0.24 and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

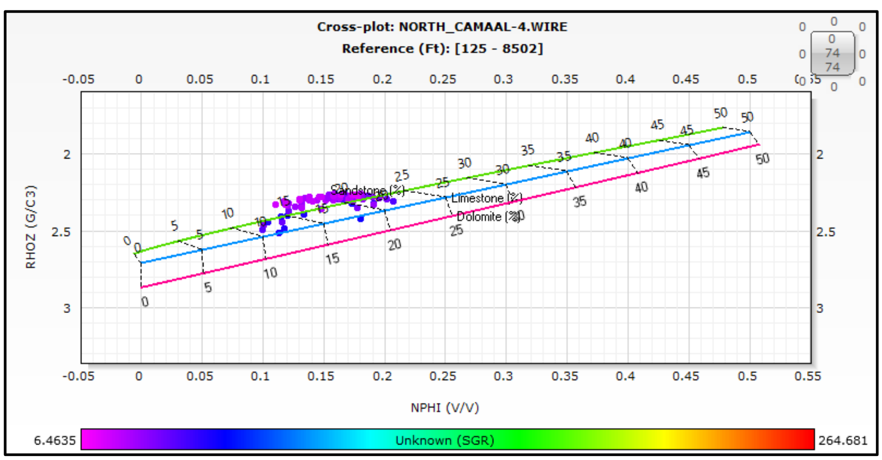


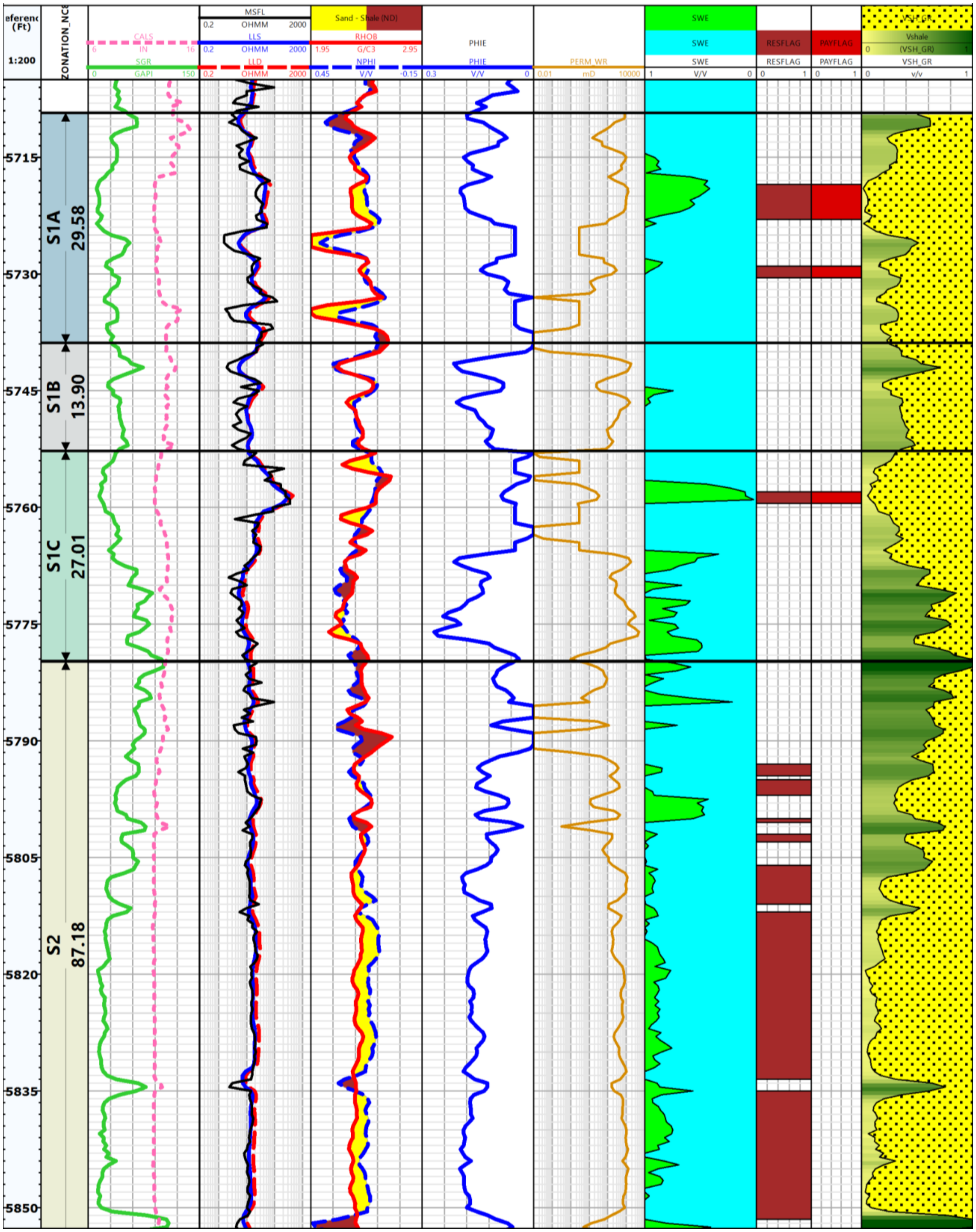
Figure 4-33 North Camaal 4 S3 – 3D Cross-plot

4.2.2 North Camaal 8:

Three main reservoir units were identified in the North Camaal -8 log namely S1A Sands, S1C Sands and S2 Sands are present. These three sand units are of Cretaceous age and interbedded with shale. The S1A unit of Cretaceous age is the main sandstone reservoir unit in the North Camaal -8 with thickness up to 30 ft encountered in NC-8 well log, which is interbedded with shale. S1A has oil bearing zone (narrow cross over) located in the middle S1A unit with water stuartion (Fig. 4.35).

Table 4 North Camaal 8 - Petrophysical Properties

North Camaal 8 - Petrophysical Properties								
Zones	**Top**	**Bottom**	**Gross**	**Net Reservoir**	**Net Pay**	**Av_Shale Volume**	**Av_Porosity**	**Av_Water Saturation**
	ft	**ft**	**ft**	**ft**	**ft**			
S1A	5709.27	5738.85	29.58	12.5	4.5	0.212	0.101	0.69
S1B	5738.85	5752.75	13.9	9.75	0	0.38	0.135	0.99
S1C	5752.75	5779.76	27.01	14.75	1.5	0.34	0.11	0.50
S2	5779.76	5866.94	87.18	69	1	0.29	0.15	0.76
S3	5866.94	5928.26	61.32	56.06	0	0.218	0.176	0.98

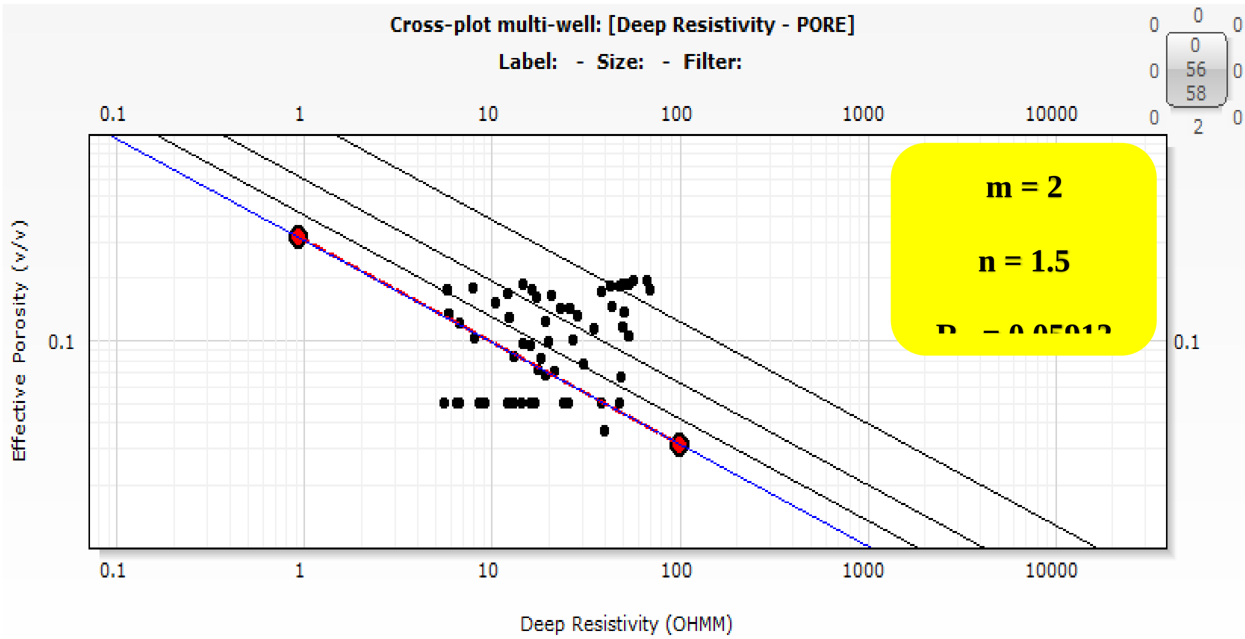


1:200
ZONATION_NC
CALS
IN
SGR
GAPI
MSFL
OHMM
LLS
LLD
Sand - Shale (ND)
RHOB
G/C3
NPHI
V/V
PHIE
PERM_WR
mD
SWE
RESFLAG
PAYFLAG
VSH_GR
Vshale
(VSH_GR)
S1A
29.58
S1B
13.90
S1C
27.01
S2
87.18
5715
5730
5745
5760
5775
5790
5805
5820
5835
5850

4.2.2.1 Pickeet Plot

m = cementation factor

n = saturation exponent



4.2.2.2 S1A

Petrophysical Description:

Based on petrophysical analysis according to table 4.2., for NC8 S1A has 30 ft thickness, we can see that it has 12.5 ft as net reservoir. The net pay is about 4.5 ft with both porosity and water saturation as 10%, 69% respectively.

Lithology:

Based on Neutron-Density as we can see from the figure 4.35 showing Neutron-Density cross-plot for NC 8(North Camaal) S1A the formation is dominantly Sandstone with minor Limestone and this is compatible with well log interpretation fig.(4.35).

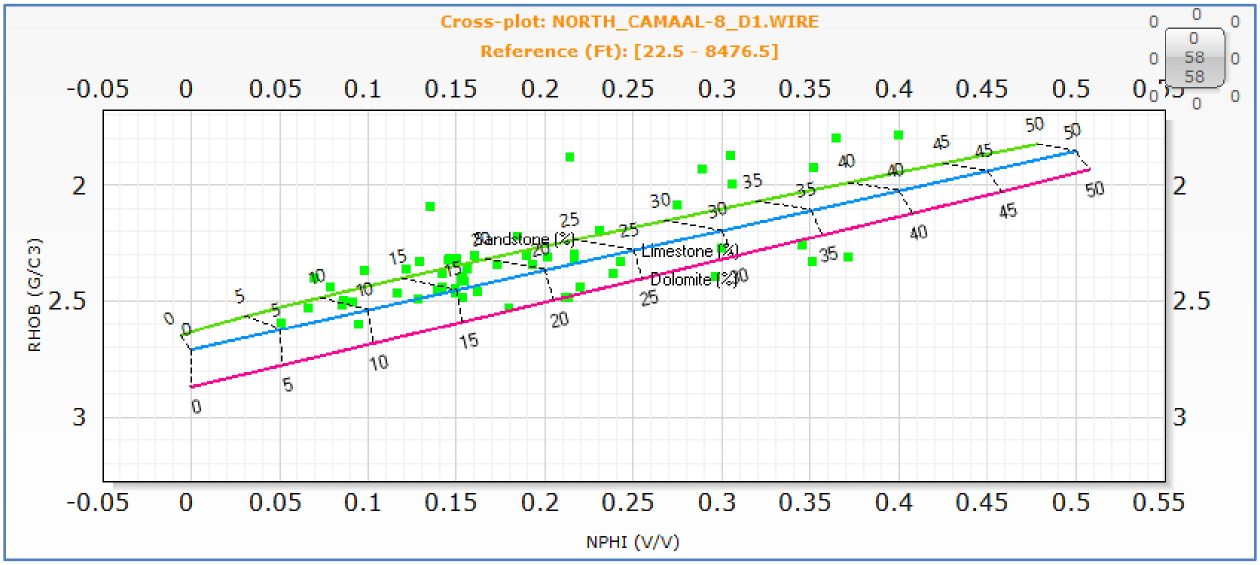


Figure 4-34 North Camaal 8 S1A – ND Cross-plot

A good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description "Sandstone: light grey, colorless, white to off white, fine to medium grains, traces coarse grains, subangular to subrounded, moderately sorted, 95% loose Quartz grains, transparent to translucent, traces Glauconite, fair to good inferred porosity, 5% consolidated with calcareous cement, friable, translucent, white to off white, traces Glauconite, fair intergranular porosity, poor to rare shows. (Unpublished Report, 2002)

Limestone: Mudstone/Wackestone, traces Packstone, white to off white, light grey, light to medium tan, moderately hard to hard, cryptocrystalline to microcrystalline, traces crystalline, abundant grey pellets embedded, traces sandy, traces Glauconite, no visible porosity, no shows. (Unpublished Report, 2002)"

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume as we can see in figure 4.36 bellow, shale content in S1A is about 21% and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

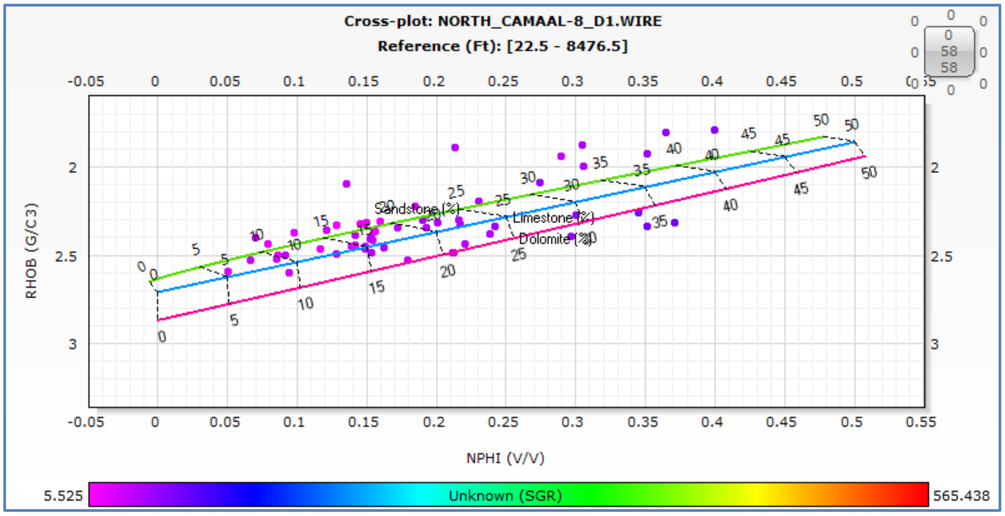


Figure 4-35 North Camaal 8 S1A – 3D Cross-plot

4.2.2.3 S1B

Petrophysical Description:

Based on petrophysical analysis according to table 4.2., for NC8 S1B, we can see that it has 9.75 ft as net reservoir. The net pay is about 0 ft with both porosity and water saturation as 13.5 %, 99 % respectively.

Lithology:

Based on Neutron-Density as we can see from the figure 4.37 showing Neutron-Density cross-plot for NC8 (North Camaal) S1B, the formation is Sandstone with Limestone interbedded with Shale and this is compatible with well log interpretation fig.(4.37).

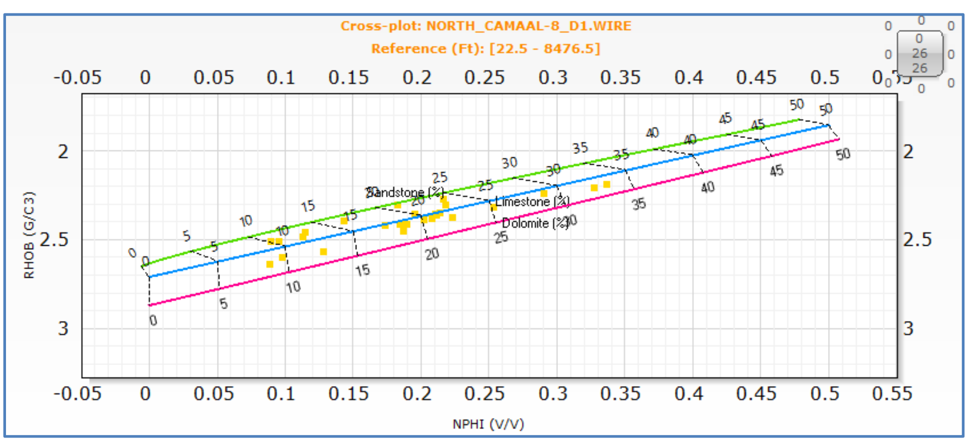


Figure 4-36 North Camaal 8 S1B – ND Cross-plot

A good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description "Shale: medium grey to grey, green grey, moderately hard, subblocky to subfissile, traces silty, non-calcareous. (Unpublished Report, 2002)

Sandstone: light grey, colorless, white to off white, fine to coarse grains, subangular to subrounded, moderately sorted, 95% loose Quartz grains, transparent to translucent, fair to good inferred porosity, 5% consolidated with calcareous cement, friable, translucent, white to off white, rare argillaceous matrix, rare Glauconite, fair intergranular porosity, poor to rare shows. (Unpublished Report, 2002)

Limestone: Mudstone/Wackestone, white to off white, light grey, traces light tan, moderately hard to hard, cryptocrystalline to microcrystalline, traces grey pellets embedded, traces Glauconite, no visible porosity, no shows. (Unpublished Report, 2002)"

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume as we can see in figure 4.38 bellow, shale content in S1B is about 38 % and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

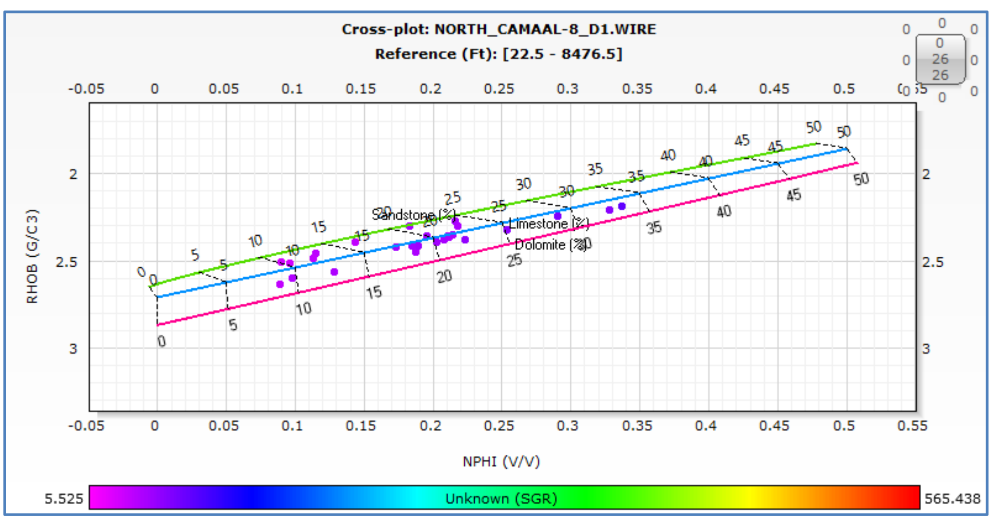


Figure 4-37 North Camaal 8 S1B – 3D Cross-plot

4.2.2.4 S1C

Petrophysical Description:

Based on petrophysical analysis according to table 4.2., for NC8 S1C, we can see that it has 15 ft as net reservoir. The net pay is about 1.5 ft with both porosity and water saturation as 11 %, 50% respectively.

Lithology:

Based on Neutron-Density as we can see from the figure 4.39 showing Neutron-Density cross-plot for NC8 (North Camaal) S1C, the formation is dominantly sandstone with minor Shale and Sandstone and this is compatible with well log interpretation fig.(4.39).

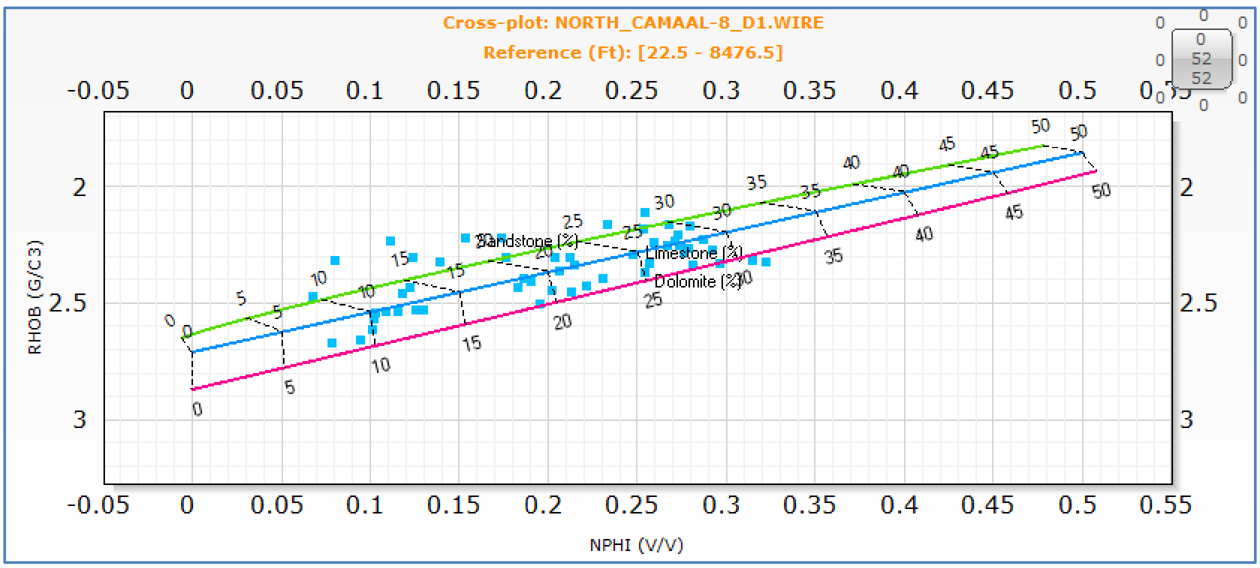


Figure 4-38 North Camaal 8 S1C – ND Cross-plot

A good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description “Shale: medium grey to grey, green grey, moderately hard, subblocky to subfissile, traces silty, non calcareous. (Unpublished Report, 2002)

Sandstone: light grey, colorless, white to off white, fine to coarse grains, subangular to subrounded, moderately sorted, 95% loose Quartz grains, transparent to translucent, fair to good inferred porosity, 5% consolidated with calcareous cement, siliceous cement in parts, friable, translucent, white to off white, rare argillaceous matrix, rare Glauconite, fair intergranular porosity, no shows. (Unpublished Report, 2002)

Limestone: Mudstone/Wackestone, white to off white, light grey, traces light tan, moderately hard to hard, cryptocrystalline to microcrystalline, traces grey pellets embedded, traces Glauconite, no visible porosity, no shows. (Unpublished Report, 2002)"

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume as we can see in figure 4.40 bellow, shale content in S1C is about 34 % and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

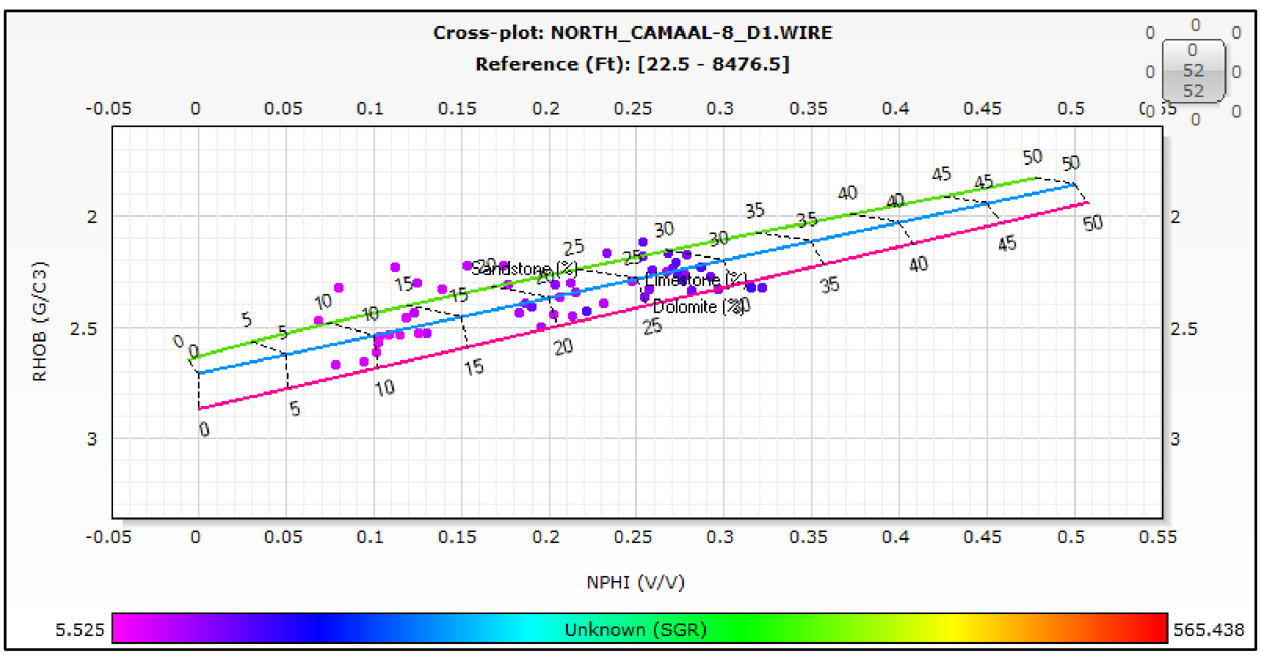


Figure 4-39 North Camaal 8 S1C – 3D Cross-plot

4.2.2.5 S2

Petrophysical Description:

Based on petrophysical analysis according to table 4.2., for NC8 S2, we can see that it has 69 ft as net reservoir. The net pay is about 1 ft with both porosity and water saturation as 15 %, 76% respectively.

Lithology:

Based on Neutron-Density as we can see from the figure 4.41 showing Neutron-Density cross-plot for NC8 (North Camaal) S2, the formation is dominantly Sandstone with Limestone and this is compatible with well log interpretation fig.(4.41).

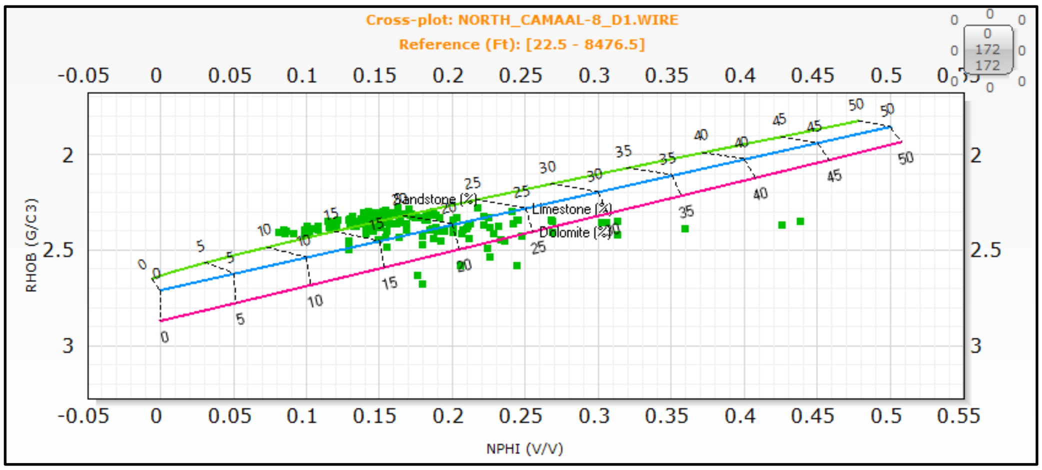


Figure 4-40 North Camaal 8 S2 – ND Cross-plot

A good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description "Sandstone: light grey, colorless, white to off white, fine to coarse grains, traces very coarse grains, subangular to subrounded, occasionally rounded, moderately sorted, 80-100% loose Quartz grains, transparent to translucent, fair inferred porosity, 0-20% consolidated with siliceous cement, calcareous cement in parts, white to off white, light greyish, dominantly fine grains, friable, translucent, traces argillaceous matrix, rare Glauconite, fair intergranular porosity, poor to rare shows. (Unpublished Report, 2002)

Limestone: Mudstone/Wackestone, white to off white, light grey, traces light tan, moderately hard to hard, cryptocrystalline to microcrystalline, traces grey pellets embedded, traces Glauconite, no visible porosity, no shows. (Unpublished Report, 2002)"

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume as we can see in figure 4.42 bellow, shale content in S2 is about 29 % and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

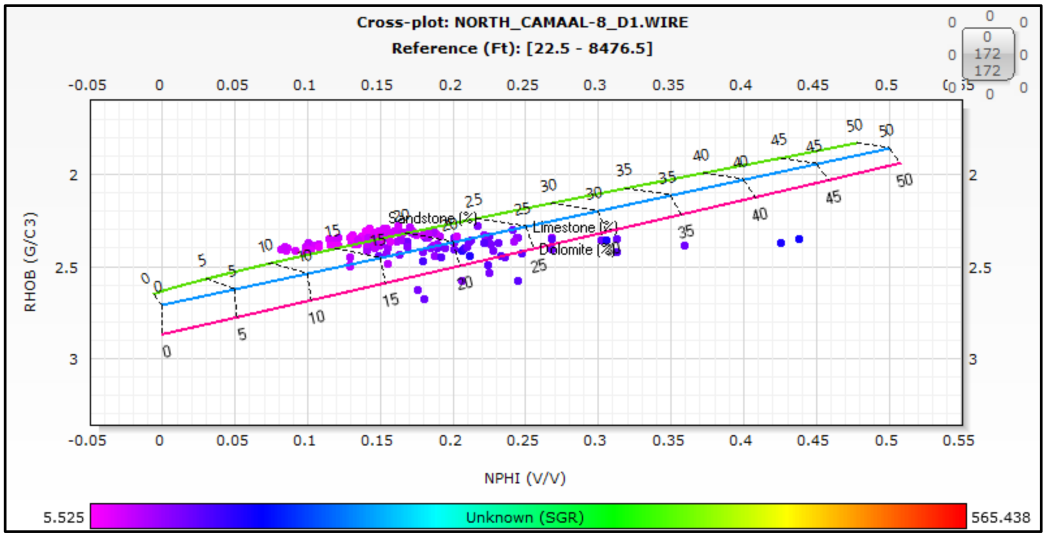


Figure 4-41 North Camaal 8 S2 – 3D Cross-plot

4.2.2.6 S3

Petrophysical Description:

Based on petrophysical analysis according to table 4.2., for NC8 S3, we can see that it has 56 ft as net reservoir. The net pay is about 0 ft with both porosity and water saturation as 17 %, 98 % respectively.

Lithology:

Based on Neutron-Density as we can see from the figure 4.43 showing Neutron-Density cross-plot for NC8 (North Camaal) S3, the formation is dominantly sandstone with some Limestone and minor Shale and this is compatible with well log interpretation fig.(4.43).

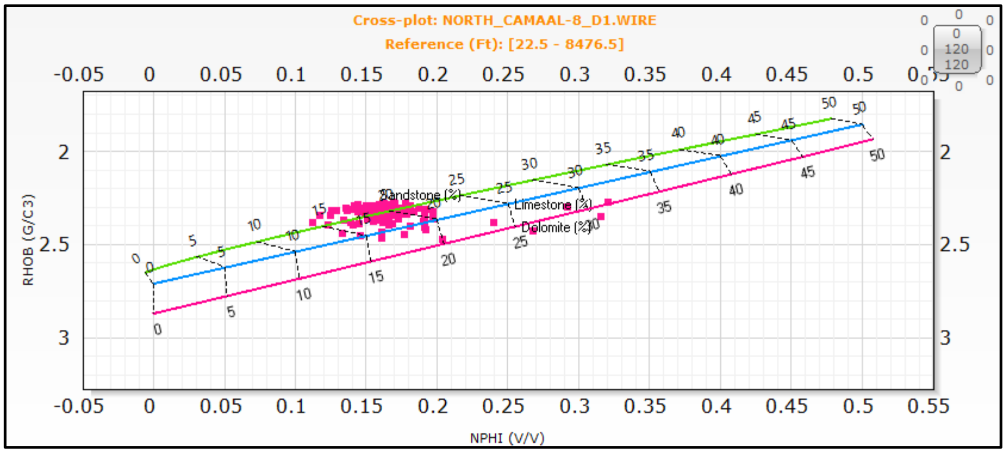


Figure 4-42 North Camaal 8 S3 – ND Cross-plot

A good matching is recognized between the results of log interpretation and cross plot above and the following mudlogging description "Shale: medium brown to brown, medium green, medium grey, off white, moderately hard, subblocky to subfissile, occasionally blocky, platy in parts, traces silty, non calcareous. (Unpublished Report, 2002)

Sandstone: light grey, colorless, white to off white, fine to very coarse grains, subangular to subrounded, occasionally rounded, poor to moderately sorted, 100% loose Quartz grains, transparent to translucent, fair inferred porosity, no shows. (Unpublished Report, 2002)"

Shale content verification:

Neutron-Density cross-plot with Gama Ray added as a third Z-axis to give an idea about clean reservoir zones and the possible increase in shale /clay volume as we can see in figure 4.44 bellow, shale content in S3 is about 22 % and a good matching is recognized between the results of cross plot below and shale volume calculated based on Gamma ray log.

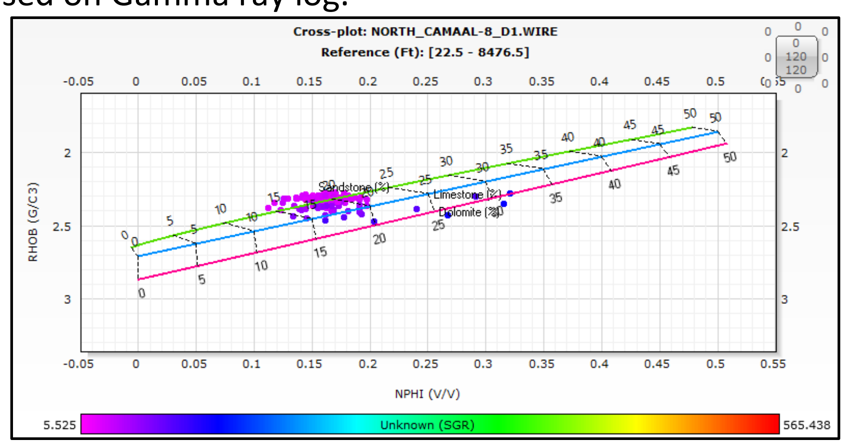


Figure 4-43 North Camaal 8 S3 – 3D Cross-plot

4.3 Engineering Analysis

4.3.1 Introduction:

Knowing the amount of original oil in place is the most important parameter for Reservoir engineers to make a quick decision whether the discovered area is Profitable or not. There are two conventional methods used to calculate the OOIP Volumetric method and Material balance method.

In this study the above two types of OOIP estimation methods have been used in S1A unit that is the major reservoir in North Camaal field.

4.3.2 Volumetric Calculation of oil-in-place:

The volumetric method depends on basic data of reservoir rock and reservoir fluid properties. Reservoir Static Model applying petrel software was used fig.4.45 for S1A unit formation.fig.4.45 is the STOIIP map for S1A which is calculated about 82 MMSTB.

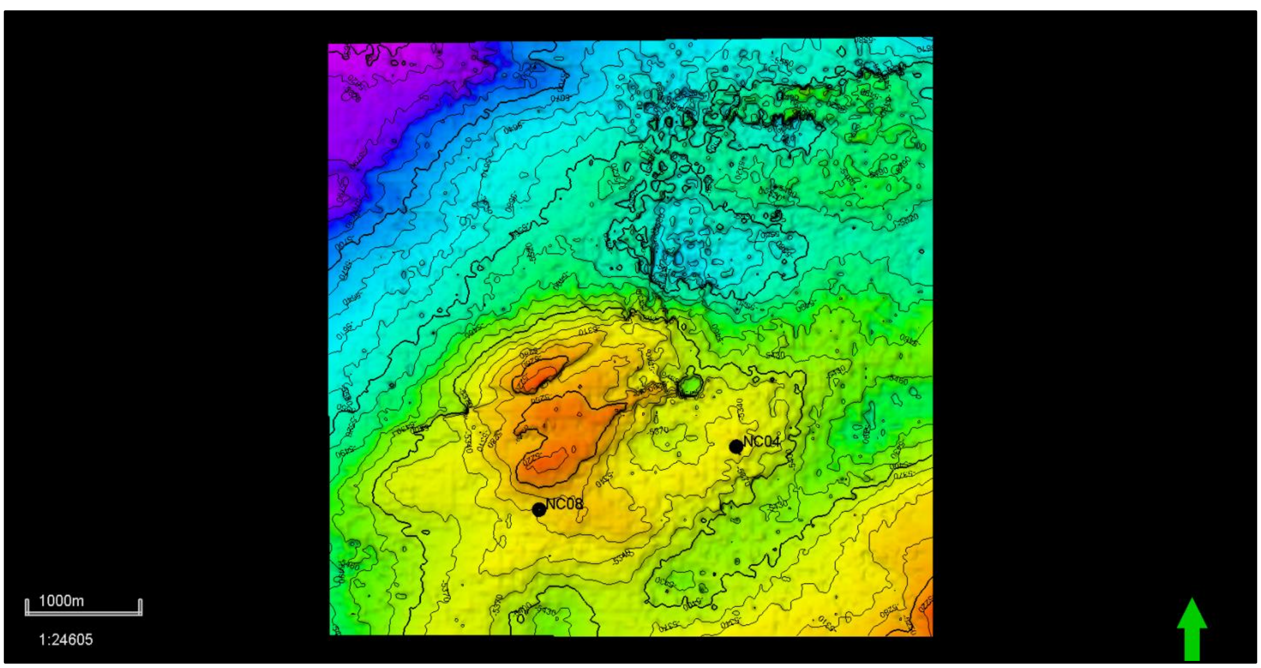
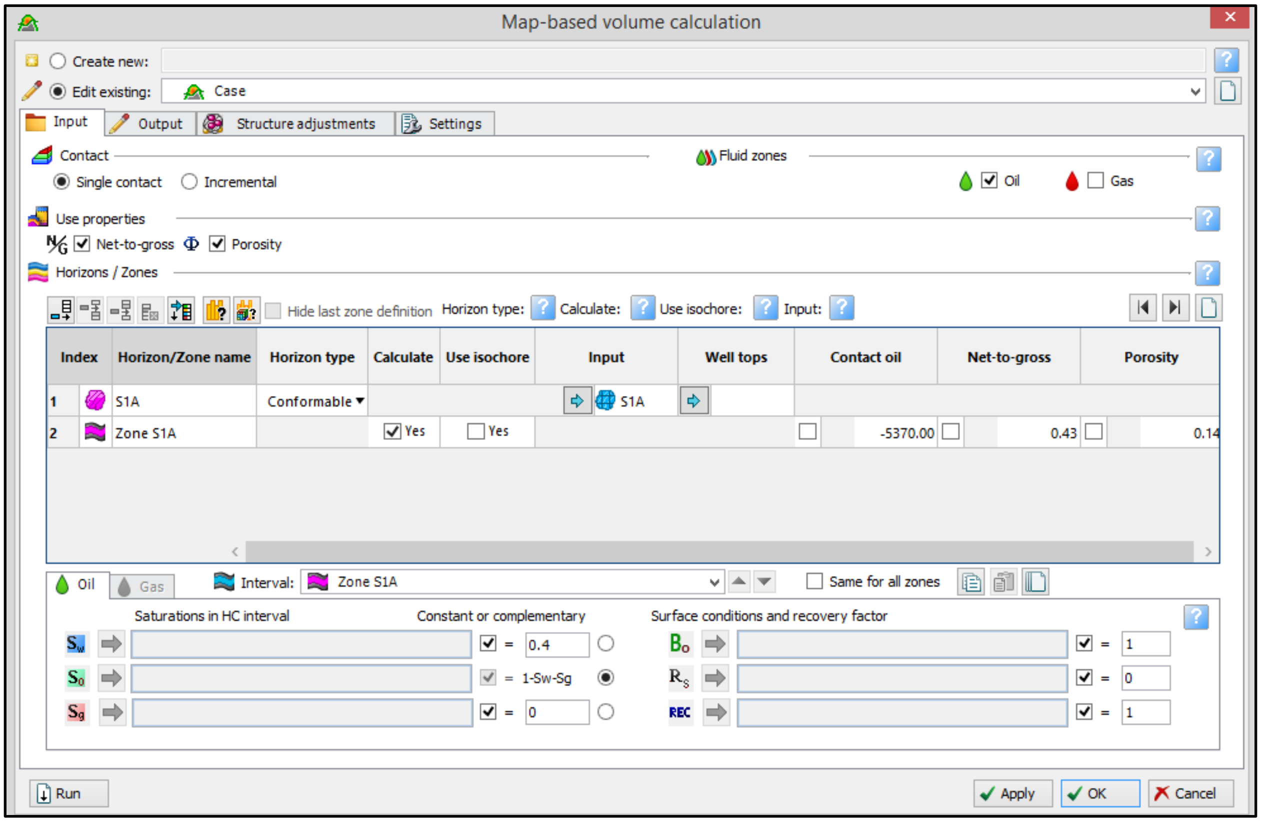


Fig. 4.45 Depth Mapp


Map-based volume calculation
Create new:
Edit existing:
Case
Input
Output
Structure adjustments
Settings
Contact
Single contact
Incremental
Fluid zones
Oil
Gas
Use properties
Net-to-gross
Porosity
Horizons / Zones
Hide last zone definition
Horizon type:
Calculate:
Use isochore:
Input:
Index
Horizon/Zone name
Horizon type
Calculate
Use isochore
Input
Well tops
Contact oil
Net-to-gross
Porosity
1
S1A
Conformable
S1A
2
Zone S1A
Yes
Yes
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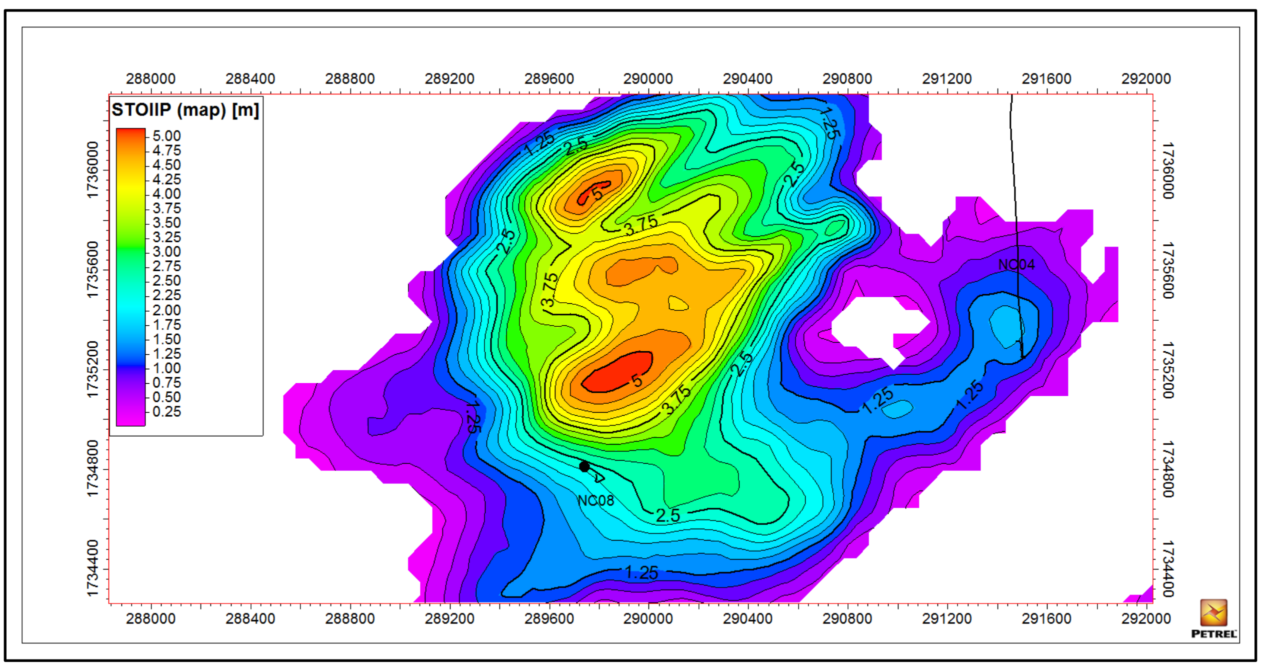
0.43
0.14
Oil
Gas
Interval:
Zone S1A
Same for all zones
Saturations in HC interval
Constant or complementary
Surface conditions and recovery factor
0.4
1-Sw-Sg
0
1
0
1
REC
Run
Apply
OK
Cancel


STOIIP (map) [m]
5.00
4.75
4.50
4.25
4.00
3.75
3.50
3.25
3.00
2.75
2.50
2.25
2.00
1.75
1.50
1.25
1.00
0.75
0.50
0.25
288000
288400
288800
289200
289600
290000
290400
290800
291200
291600
292000
1736000
1735600
1735200
1734800
1734400
NC04
NC08
PETREL

4.3.3 Material Balance Calculations:

MBE depends on combinations of fluid properties, rock properties, pressure and production data. Analytical method is used to assess the regression match between Observed/measured data used to construct this model. The value of this match is

represented by the standard deviation between model obtained by MBAL software and measured used data figure 4.46 bellow, the red line clarifies the simulator running without aquifer influx while the blue line represents the simulator running with water influx support it is acceptable match.

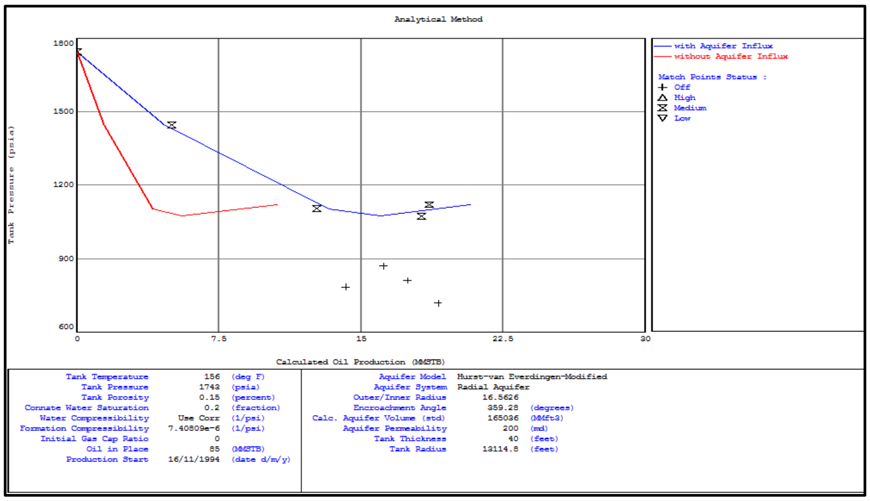


Fig. 4.46 MBAL software

As well as there is good match have been seen between the history and simulation data for Cumulative oil and water and gas production fig.4.47

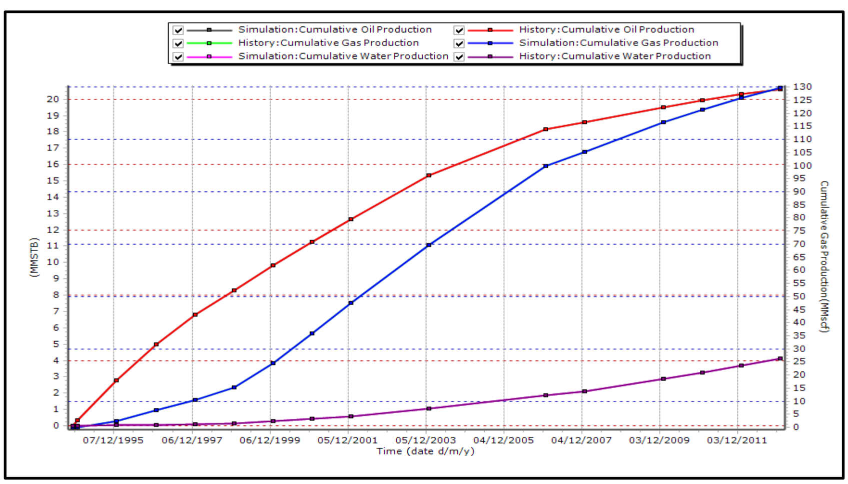


Fig. 4.47 history and simulation data

Fig. 4.48 describes the fractional contributions of drive mechanisms of the recovery of S1A unit. It can be noticed that there are four energy sources are affecting the recovery of oil which are water influx illustrated in pink colour section, pore volume compressibility represented in green colour section,water injection in yellow colour and little impact of fluid expansion clarified in blue colour section. From Analytical plot, it could be understand the water influx the main reservoir energy supporting.

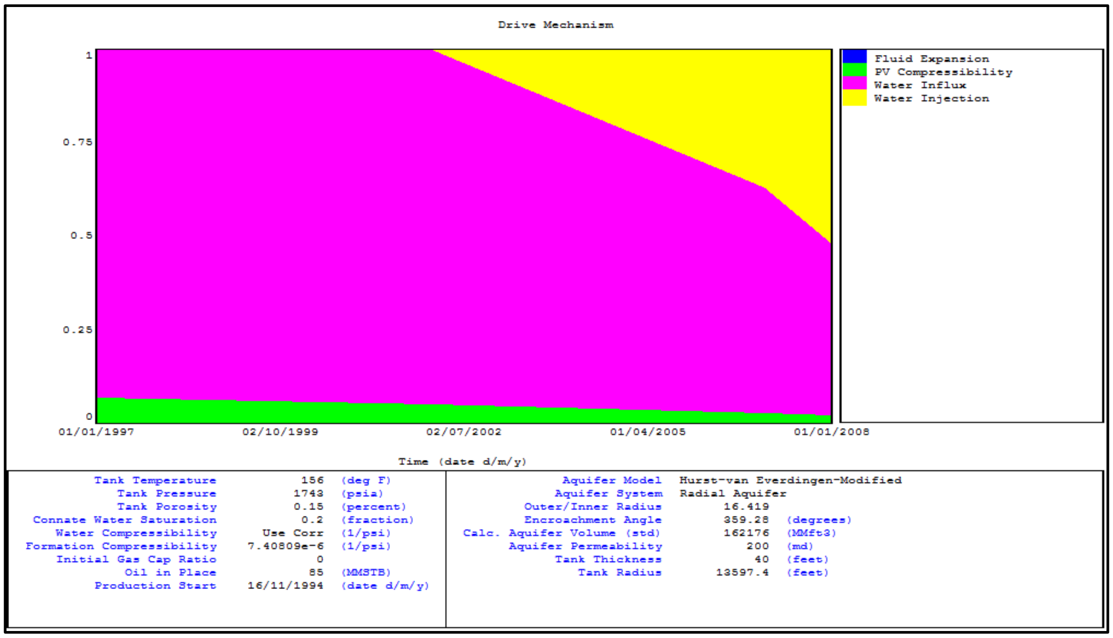


Fig. 4.48 S1A

The OOIP obtained by Material Balance Equation (MBE) is about 85 MMSTB for S1A which is close to the volumetric calculation of the same formation.

CHAPTER FIVE

5.1 Conclusion

According to the results analysis and observations the following conclusions:

1. Reservoir properties from log analysis were augmented by similarly detailed 3D seismic characterization and stratigraphic correlations, along with core data for one of the studied wells, to provide **an accurate result for Qishn formation**. Which then was used in the determination of the hydrocarbon potential by both the volumetric method, and MBE calculations.
2. In the petrophysical analyses we observed that there are three main reservoir units were identified in the North Camaal field namely S1A Sands, S1C Sands and S2 Sands. These three sand units are interbedded with shale. The S1A unit is the main sandstone reservoir unit in the North Camaal field.
3. The utility of cross-plots between the implied petrophysical parameters along with core and mud logging description data for some zones are helpful to delineate the lithology. By this way, the Qishn Formation is composed mainly of sandstone with shale, limestone and dolomite
4. The detailed petrophysical analysis has showed that the hydrocarbon content of the S1A subunit whenever found, is mainly concentrated at the middle part of the unit associated with low shale (13%-21%) content, good effective porosity (11%-14%) and high permeability records, with water saturation (40%-60%).
5. From the seismic study, for each 15% porosity, the permeability is 450. The average porosity ranges between 6.4% to 15.7% in Qishn reservoir, which get acceptable correlated with the petrophysical analysis of the average porosity.
6. From the interpretation of the 3D seismic data, the structure of study area seems to be a faulted anticline structure. The petrophysical analysis show that the accumulated hydrocarbons in the Qishn sandstone is entrapped capped and sealed by the considerable thicknesses of the overlying impervious Red Shale and Qishn Carbonates as well as the overburden rocks. These rocks include the Late Cretaceous and younger post-rift deposits. Madbi shales of the Jurassic rifts constitute the main source rock of the generated hydrocarbons that migrate upward until they are trapped generally within the Qishn sandstone reservoirs (USGS, 2002).
7. A seismic inversion analysis along with petrophysical results has been carried out in order predicted porosity and facies in the inter-well spaces of the Qishn formation, North Camaal field. The consequences showed a

good agreement between log based and seismic inversion-derived porosity

8. (AI) cube, porosity, permeability and pore pressure cubes help in determine the new prospected area which may help in future planning and development of new wells.
9. According to the seismic and static modeling, both the centeral and north-west region of North Camaal should be the focus of new producers drilling, because it’s where hydrocarbon accumulates the most in Qishn reservoir.
10. The estimation of original oil in place (OOIP) was carried out by two methods which are volumetric method applying petrel software, Material Balance using MBAL software for S1A unit formation.
11. The results which were obtained by volumetric method were 82 MMSTB While by MBAL software was (85 MMSTB. The percentage of error between Material Balance and volumetric equation was 3.5% that is acceptable.

5.2 Recommendations

Based on the results of the study, the following recommendations are provided for future study.

1. Further technical study is recommended when more data is available.
2. Seismic shows an anomaly of high under pressure in the base of Saar_Carbonates. We recommend a Geomechanically study to be done in that part of the Masila stratigraphic column as a whole, because we observed that it also has a low resistivity, which is a sign of hydrocarbon presence. It also has high density which means it’s tight and needs fracturing to facilitate hydrocarbon flow. Such formation can be very productive when Geomechanically studied and fractured properly according to a similar occurrence a carbonates formation in Texas, USA
3. An aquifer study is recommended to incorporate in MBAL software
4. Advance petrophysical analysis is recommended

5.3 Limitations

In general, the objectives of the project have been achieved, despite some limitations which are mainly related to unavailability of some data. These limitations can be summarized as the following:

1. In this study a suite of two wells in North Cammal was used. Although the combination of multiple disciplines helped on obtaining very good accuracy of the characterized reservoir, if more well logs and core were to be available it would be better for reaching even higher accuracy.
2. Canadian Oxy, which is the operator of the field for many years didn't execute pressure tests enough for every year over year like other operators in Iraq at the time which could helped us in in reaching excellent accuracy with MBE.
3. Difficult to obtain case studies

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