

Kumar Hemant Singh
Ritesh Mohan Joshi *Editors*

Petro-physics and Rock Physics of Carbonate Reservoirs

Likely Elucidations and Way Forward

 Springer

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Preface

Carbonate reservoirs hold 60% of the world's hydrocarbon reserves. In order to obtain a reliable estimate of reserves in a given reservoir and also to prepare a development plan for optimum production of hydrocarbons from the reservoir, a quantitative assessment of the petrophysical parameters of the reservoir is essential. However, petrophysical properties of carbonates are not easy to predict because of the post-depositional processes like dissolution, re-crystallization and re-precipitation, which alter the properties of the carbonate reservoirs and make them extremely heterogeneous and, hence, bear a profound effect on the productivity and flow dynamics in the reservoir. However, we lack an adequate understanding of how to dynamically model these post-depositional processes. The evolution of porosity through dissolution channels, solution vugs, fractures, etc., is all post-depositional processes. For realistic modelling of the reservoir, we need to understand the dynamics of the fluid flow through the complex network of the carbonate matrix. This calls for proper integration of various geophysical, geological, petrophysical, core data and dynamic data such as MDT, PLT, well test analysis.

Although the challenges in the study of carbonate rocks have led to the development of many techniques, these technologies largely have been patented and, therefore, are not accessible to all workers in this field. With an objective of sharing whatever sharable information is available in the industry and academia in India, a workshop was organized at IIT Bombay in November–December 2017. This volume is an outcome of the deliberations in the workshop.

The volume has been divided into various sections based on the review of the geo-scientific data by different workers in this field in order to understand the various aspects of carbonate reservoirs which make them different from a clastic reservoir. The first section discusses the geological processes in carbonates from a perspective of distribution of porosity and permeability and fluid flow properties of the reservoir. This includes historical review and latest trends on different rock characterization techniques that are being employed by the researchers globally.

Due to the diversity and inherent heterogeneity of carbonates, various laboratory-based results are classified among various empirical models derived for carbonates. This comprises the second section of the proceedings. The laboratory

experiments combined with the log data including high-resolution data acquired by the oil and gas industries are used to develop petrophysical and rock physics models of reservoirs which comprise the next section of the volume. Integrated with seismic data, the existing and new trends in providing solutions to seismic reservoir characterization form the subsequent section of the volume. Characterization of clastic reservoirs and challenges to the wellbore instability problems is addressed in the final section. It is hoped that these proceedings will provide a useful reference for the researchers and practitioners in this field. Your feedback will be valuable for organizing workshops in this field in future.

Mumbai, India

Kumar Hemant Singh
Ritesh Mohan Joshi

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We are indebted to Indian Institute of Technology Bombay, Department of Earth Sciences, and especially to the then Head of the Department Prof. T. N. Singh for their guidance, support and logistics during the workshop and throughout the making of this publication.

This book would not have taken shape without the support of all the contributing authors belonging to geologically and geographically diverse places and institutions. The editors from bottom of their heart are indebted to all of them for the time they took to pen down their finding and research so that it can be disseminated with a larger audience. Special mention is for a highly talented and experienced industry professional Mr. U. S. D. Pandey (for keynote address), Mr. P. P. Deo, Mr. K. Vasudevan and Mr. A. Dave all from ONGC, India, for their respective talks and astound academician Dr. Ravi Sharma, Professor from IIT Roorkee, for revising the content and themes related to carbonate reservoir workshop besides contributing to the papers in the book.

We would like to express our deepest appreciation to Dr. C. H. Mehta (Ex-Executive Director and Head, Geopic, ONGC), Dr. Sandip Kumar Roy (Consulting Geologist) and Mr. Asit Kumar (Consulting Geophysicist) for their timely contribution in critically reviewing the papers, editing the articles and making the content easier to understand for the readers.

This book would not have been a reality without the typesetting work and continuous support of Indian Institute of Technology Bombay research students Mr. Anil Kumar, Mr. Anup Shahi and Ms. Arpita Adhikary. They have been the

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Last but not least, to the efforts of all those behind the scene and whose names are not captured here, we would like to take a bow to show our gratitude towards you.

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Part I
Geological Processes and Rock
Characterization Techniques

Chapter 1

Carbonate Reservoirs: Recent Large to Giant Carbonate Discoveries Around the World and How They Are Shaping the Carbonate Reservoir Landscape



Ritesh Mohan Joshi and Kumar Hemant Singh

Abstract Carbonates are very heterogeneous when compared to clastic reservoirs in terms of reservoir properties. Yet, some of the biggest discoveries in recent times have come from carbonates alone. In 10 years, between 2006 and 2015, there have been four major discoveries and some of them have the potential of being called giants and supergiant. First, it was Tupi discovery renamed as Lula in the pre-salt which opened a new play in the deep-waters of Santos basin. A few more discoveries followed in the same play but then the next big discovery, even bigger than Lula, came in the year 2011 with the discovery of another Oil pool Libra in the same basin. Till 2006, Santos basin was underexplored as it was considered a frontier basin and all the focus was in the neighbouring Campos basin where there were many pre-salt and post-salt discoveries. Post-2006, with a couple of discoveries, the Lower Cretaceous carbonate reservoirs have come up as a new play in the upper Synrift and post-rift sequences. Looking at the tectonic reconstruction of the plate, 140 million years ago (Early Cretaceous) the conjugate margins of Brazil and Angola were juxtaposed before the opening of south Atlantic. This also tells us that Santos and Campos basin of Brazil was located adjacent to Benguela and Kwanza basin of Angola. It is common wisdom that two basins with similar geological history should have similar hydrocarbon prospects. So, the question was whether the pre-salt success of Brazil would recur in Angola where pre-salt drilling was nearly absent before 2011. The answer came with the discovery of Azul by Maersk, which proved a working petroleum system and later Cameia discovery by Cobalt in 2012. With reserves to the tune of 30 TCF (5.5 billion BOE) housed in a 100 km² of carbonate mound, it has a potential to become one of the largest gas discoveries of the world. It is already the biggest in Egypt and the Mediterranean. These discoveries and many more are changing the carbonate reservoir landscape. Once upon a time when talking about Carbonates, the reservoir of Middle East basins used to come to mind, not any more. In the age of globalization, it appears that carbonates and large to giant carbonate discoveries have also globalized.

Keywords Carbonate discoveries · Santos Basin · Lula · Cameia · Libra

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1 Introduction

Carbonates and Clastics are the main two reservoir rocks considered in hydrocarbon exploration and production. Globally, more than 60% of the oil is hosted in carbonate reservoirs (Roehl and Choquette 1985). 62% of the world's proven conventional oil reserves are in Gulf Countries. 70% of these oil reserves are contained in carbonate reservoirs. Carbonates can be formed by both biochemical as well as inorganic processes. However, it is observed that the deposition of most of the carbonates in the world is controlled by biological activities (Moore 1989). Carbonate deposition needs very specific environmental conditions in reference to light, temperature, salinity and the availability of nutrients. Therefore, most carbonates are formed in tropical, shallow marine depositional environment. These rocks are prone to significant diagenetic changes as they are highly susceptible to chemical alteration, re-crystallization and dissolution processes (Major and Holtz 1997). Giant hydrocarbon fields are discovered and being exploited in the Middle East, Russia, Kazakhstan and Libya. The world's largest conventional oil field in Saudi Arabia is Ghawar which contains multi-billion barrels of oil reserves in the Jurassic carbonate. 54.5% of the newly discovered significant hydrocarbon reserves have been found in marine carbonate and 12% in the lacustrine carbonates during 2000–2012 (Bai and Xu 2014).

A number of significant oil and gas discoveries have been made in carbonate reservoirs around the world in the last decade. Tupi and Libra oil discovery in Brazil by Petrobras in 2006 and 2011, respectively, Cameia discovery in Angola by Cobalt International Energy in 2012 and Zohr gas discovery in Egypt by ENI in 2015 (Eni 2015) are real game-changers. New play types in carbonate have opened up through these big hydrocarbon findings. Giant oil discoveries have been made in Pre-salt carbonate reservoirs in Santos Basin in Brazil and Pre-Caspian salt basin in Kazakhstan (discovered in 2000).

2 Petroleum System

The generation and entrapment of hydrocarbon in the above mentioned giant discoveries are well related to the tectonic evolution of the basins. Large scale intraplate rifting between South America and Africa during the final breakup of western Gondwana in Late Jurassic—Early Cretaceous resulted in South Atlantic rift basins (Heine et al. 2013). The Santos basin in Brazil and Benguela basin in Angola were formed during the last stage of the breakup of the conjugate margin at around 113 Ma (Heine et al. 2013). Microbialite and coquina are the main carbonate rocks identified as hydrocarbon-bearing reservoirs within these rift basins on both sides of the margin. These carbonate rocks are sealed by evaporates which were deposited in shallow marine condition during the first marine transgression in Aptian. The origin of these carbonates is quite controversial. One school of thought is that the carbonates are

associated with reefs and other buildups (stromatolites) formed during various stages of sea-level rise. However, the other model suggests chemical precipitation of carbonates in travertine condition with secondary biogenic growth (Mohriak 2015). This Barremian/Aptian pre-salt carbonate play in upper rift/sag phase in Brazil offshore is proven to be prolific in terms of hydrocarbon reserves after the discovery in 2006. Lula oil field estimating around 5–8 billion barrels, Lara estimating about 3–4 billion barrels, Libra oil field of around 8 billion barrels, are but a few giant discoveries in pre-salt carbonates in Brazil. Libra oil field has an approximate area of 1500 km².

The conjugate margin Campos basin in Brazil is the Kwanza basin in Angola on the other end of Atlantic. Microbialite and coquina are reported in the Syn-rift Lower Cretaceous play in Kwanza basin, Angola, similar to that of Campos Basin in Brazil. The carbonate Syn-rift is capped by Aptian salt in Kwanza basin which also witnessed many significant oil and gas discoveries in 2012. Benguela and Namibe basins in West Africa are the conjugate margin of Santos basin of Brazil. However, this part of the West African margin is affected by Valanginian volcanics (Teboul et al. 2017). High concentration of Carbon dioxide in the present-day deep-water of the Lower Cretaceous Syn-rift play associated with deep-seated faults is also reported in Kwanza basin.

The recent discoveries have changed the landscape of the Carbonate reservoirs. Here we discuss only a few major discoveries during the 10-year span from 2006 to 2015. These discoveries have made a significant change in the way we look at the carbonate reservoirs. Some are deep to very deep, some are extensive, while some are in places, which, a few years back, were not possible to even map (shadow zone). We discuss these interesting discoveries in the subsequent sections.

3 2006—Tupi (Now Named Lula) Oil Discovery—Brazil—Petrobras

The discovery of the Tupi oil field (Renamed as Lula) in Brazil (Fig. 1) was a historic event. Petrobras drilled Lula in deep-water of Santos basin (Petrobras 2010). In 2100 m of water depth, the well was drilled about 5200 m from mudline. So, a total well depth of 7300 m was quite deep and resulted in a high cost of over \$200 Million.

Despite its very high drill cost, the well proved rewarding. The 2 km of thick salt bed is underlain by 6 billion barrels of Oil in HPHT condition.

Coming to the petroleum system, the organic-rich lake shale is the main oil source. Lacustrine beach sands, porous limestones and dolomites (Microbialites) are the reservoirs and impervious salt acts as a seal. Figure 2 shows a seismic line passing through Lula (Tupi) discovery with the massive evaporates acting as a seal, which can be seen in magenta above the Microbialites reservoir.

The carbonate rocks (limestones and dolomites) that are associated with growths of algae known as stromatolites are referred to as Microbialites. These kinds of stromatolites can be seen in present-day Shark Bay, Australia. The reservoir in which

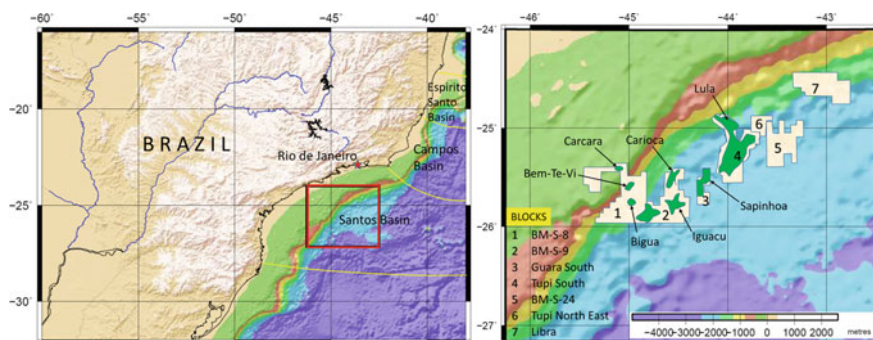


Fig. 1 Location map of Lula and Libra discovery (reproduced with permission from Koning 2015)

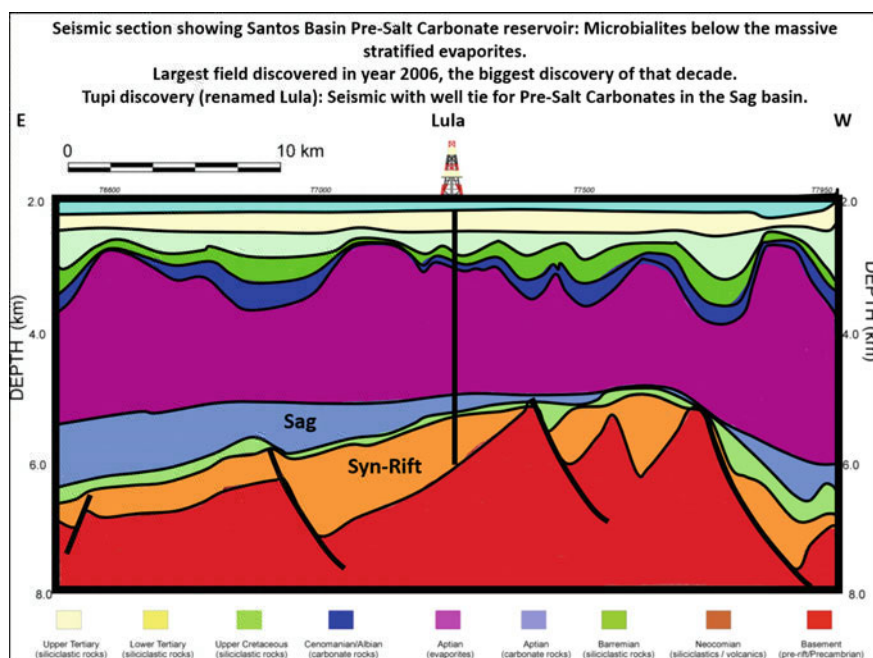


Fig. 2 Geological cross-section showing the location of Tupi (Lula) discovery well. (<https://www.aap.org/publications/copyright>, Modified after Mohriak 2015)

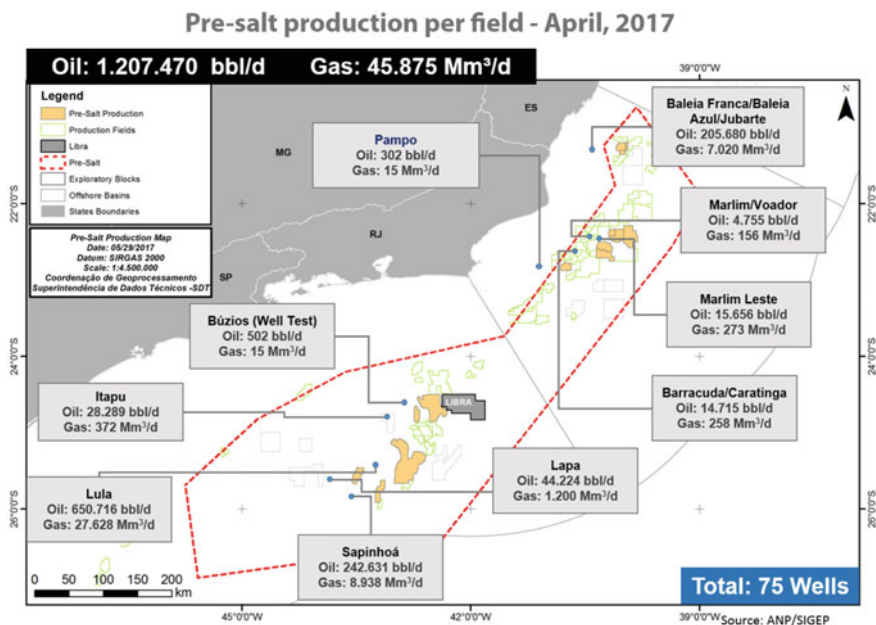


Fig. 3 Field wise production per day from pre-salt reservoirs (reproduced with permission from Oddone et al. 2017)

top section is Microbial carbonates in the sag sequence and the lower section is Coquinas of the Syn-rift sequence mostly have typical vuggy porosity with 9–12% range and permeability pegged at 100 mD.

As per Offshore Technology (Petrobras Dec 30, 2010), today the recoverable volume in the Lula Field is 6.5 billion BOE with 28° API, while the recoverable volume in the Iracema area, Cernambi Field is 1.8 billion, with 30° API. The total recoverable volume amounts to 8.3 billion BOE.

As per the latest numbers shared by ANP 2017–2019 bidding rounds document, the Lula is producing 650,716 bbl/d of oil and 27,628 Mm³/d of gas. Referring to Fig. 3 which is taken from ANP document from June 2017 “Oil and Gas Opportunities in Brazil; 2017–2019 Bidding Rounds”, it is clear that around 75 wells in the Pre-Salt reservoirs are producing a total of ~1.2 million bbl/d of oil and ~46,000 Mm³/d of gas as of May 2017, which is suggestive of an extremely good production. This is without the contribution of Libra production.

4 2011—Libra Discovery—Brazil—Petrobras

Lula was a game-changer, and it changed the game rapidly not only in the deep-water of Santos basin but also nearby Campos basin. Since Lula, many more pre-

salt discoveries (Carioca-Sugar Loaf, Jubarte, Lara and also gas giant Jupiter) have taken place and the number of recoverable hydrocarbons is increasing steeply. As an estimate by private agencies, the pre-salt oil reserves could be 20–30 billion barrels whereas as per ANP: National Agency of Petroleum, Natural Gas and Biofuels, the number stands at somewhere 50 billion barrels.

Around 230 km off the coast of Rio de Janeiro in the Santos basin and north of giant Lula field (Fig. 1) lies an ultra-deep-water oil field named Libra which was discovered in May 2010. Libra covers an area of 1550 km² and the reservoir is below 2000 m of water and approximately 5000 m of sand, rock and shifting salt layer. Figure 4 shows the Geological section through the Libra discovery where the thick salt is marked in magenta colour and the reservoir is in faded sky blue just below it. The oil–water contact is clearly brought out in the seismic section (not shown here).

As reported in Total's website which was last updated in September 2016 (Total 2016) an article in World oil, one of the world's largest offshore oil and gas accumulations is Libra field where the recoverable reserves are estimated to be 8–12 billion BOE. This makes the earlier discovery of the decade (Lula) looks smaller and had to settle for the next largest discovery in ten years after Kazakhstan's 17.2 billion bbl Kashagan Field.

In a presentation made by Bruno Moczydlower of Petrobras (Moczydlower 2014), who is also Libra Reservoir Manager and SPE Brazil Section Chairman, outlines the

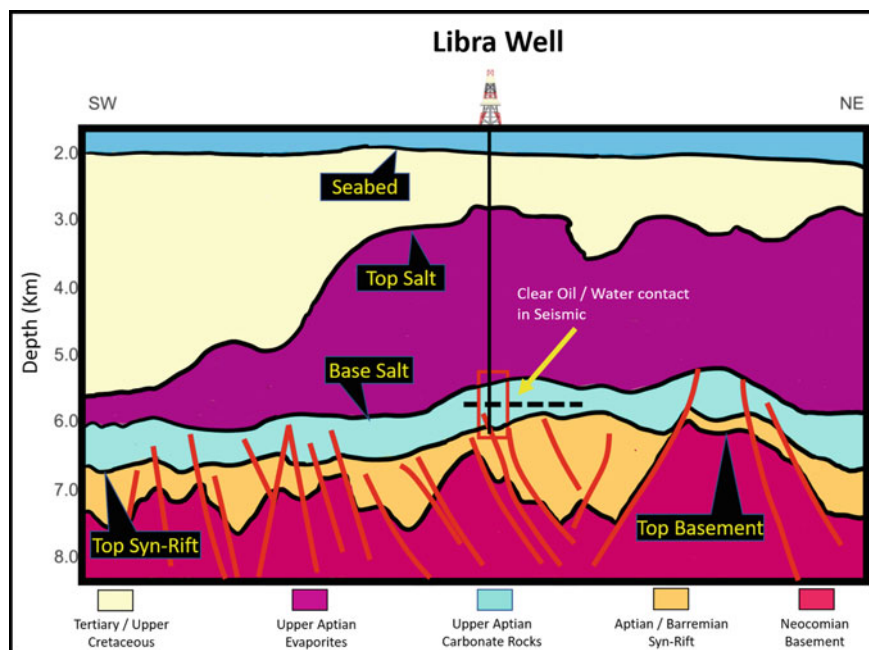


Fig. 4 Geological cross-section showing the location of Libra discovery well (<https://www.aapg.org/publications/copyright>, modified after Mohriak 2015)

main characteristics of the reservoir. He mentions that the Libra reservoir is a very thick pre-salt reservoir with good reservoir quality in terms of permeability and porosity. The oil is light of around 27 API with low H₂S and high GOR (440 m³/m³) but the CO₂ content is slightly higher of about 44%. From the structural map of the base of salt (top of the reservoir) there are a few numbers worth noting for structure Libra2 C1. Referring to Libra Base of Salt Structure Map, Moczydlower (2014) shows that the spill point is at around 5700 m, the area above the oil-water contact is 578 km², the reservoir top is at 4750 m and the maximum gross pay is around 950 m. Similarly, from the well log of well 2-ANP-2A-RJS (Moczydlower 2014), the reservoir parameters look impressive. The gross pay is around 329 m, with net pay of around 278 m which gives an N/G ratio of ~85%. The poro-perm is calculated to be 14% and 13%, respectively.

5 2012—Cameia Discovery—Angola—Cobalt International Energy

The first month of the year 2012 and Maersk was happy to announce its first well Azul-1 to penetrate pre-salt reservoir in the deep water of Angola block #23. The total depth drilled by the well was 5330 m out of which the water column was 920 m. Among the many firsts, this was the first deep-water well in the Kwanza basin that targeted the pre-salt reservoirs (Fig. 5).

The second month of the year 2012, and this time Cobalt International Energy (CIE) was happy to announce the results of its well Cameia-1. This was drilled in slightly deeper water (i.e. 1680 m of water) in deep-water Block #21 (Fig. 6). A 360 m of gross Oil column with 75% N/G was penetrated in the Pre-Salt target reservoir.

In the absence of any clear gas–oil or oil–water contact on wireline logs an extended DST was performed. The production of the well was at 5010 bopd of 44° API oil and 14.3 million cubic feet per day of gas which approximately amounts to a total of 7400 bopd.

The well result actually surprised and surpassed all expectations. The reservoir had 365-m-thick oil column and 275-m-thick gas column with over 75% N/G ratio (Fig. 7). The reservoir is highly permeable and fractured carbonates. The area is between 20 and 101 km².

6 Angola's Petroleum Systems

The Azul and Cameia well discoveries in the Kwanza basin confirmed a working pre-salt petroleum system similar to their conjugate margin in Brazil. It helped to de-risk the play.



Fig. 5 Location map of the Kwanza basin showing major discoveries including Azul-1 and Cameia-1 (Cobalt 2012)

Angola's hydrocarbon-bearing basins are namely Kwanza, Congo and Namibe. So far only Kwanza and Congo have discovered oil in commercial quantities while Namibe Basin remains underexplored.

A very strong Lower Cretaceous and Tertiary petroleum system is the reason behind the success of Cameia discovery. Continental breakup during Early Cretaceous (Fig. 8) developed lacustrine rift basins and Bucomazi formation, an organic-rich shale became the main source rock for the pre-salt traps in the Kwanza basin.

7 2015—Zohr Gas Discovery—Egypt—ENI

The mother of all discoveries, however, was Zohr discovery, offshore Egypt (Eni 2015). No wonder when someone exclaimed! "The truth? I have never seen 600 m of gas permeated rock with pressure point so aligned". Let's have a look at why this is known as a supergiant.

With over 850 billion cubic meters (30 TCF) of lean gas resources, or 5.5 billion BOE housed in a 100 km² field is undoubtedly the largest discovery of Egypt and in the Mediterranean Sea which has a potential of becoming one of the world's largest natural gas field. Located in the deep-water of Egypt' Shorouk block at a water depth of 1450 m the field was announced on August 30th, 2015. A total depth of approx.

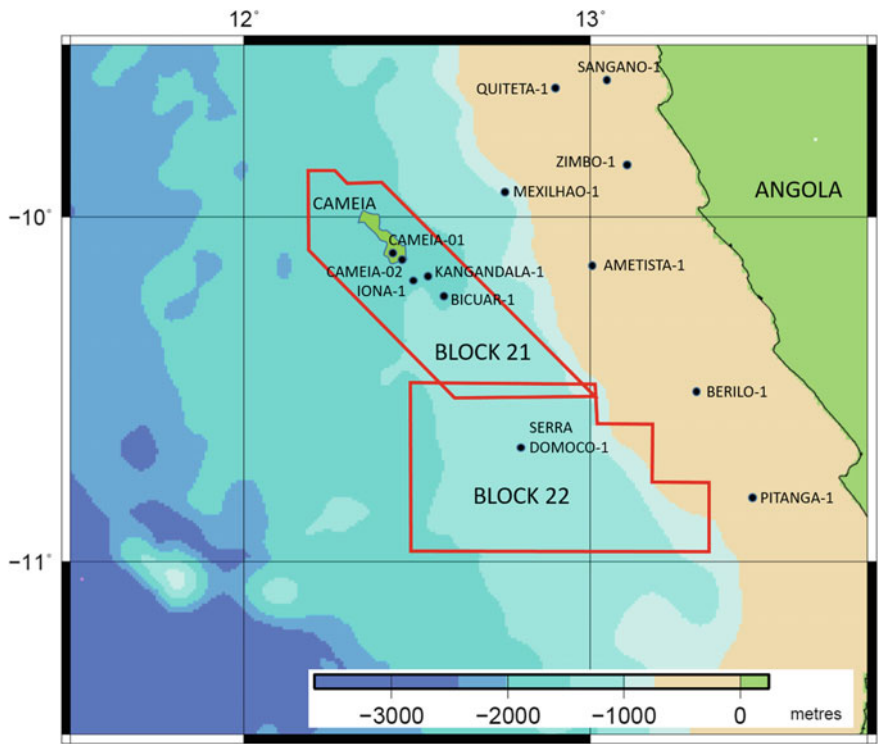


Fig. 6 Block location map of the Kwanza basin showing block #21 and discovery well Cameia-01 (reproduced with permission from Duval et al. 2015)

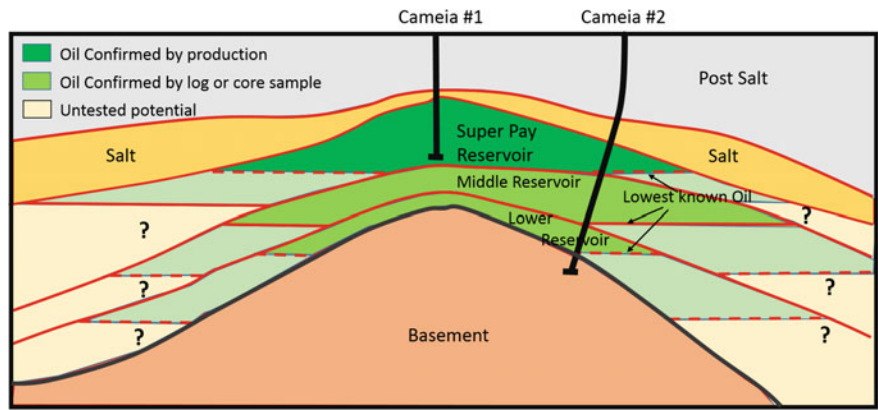


Fig. 7 Geological cross-section of the discovery well Cameia-1 and also Cameia-2 well (modified after Koning 2014)

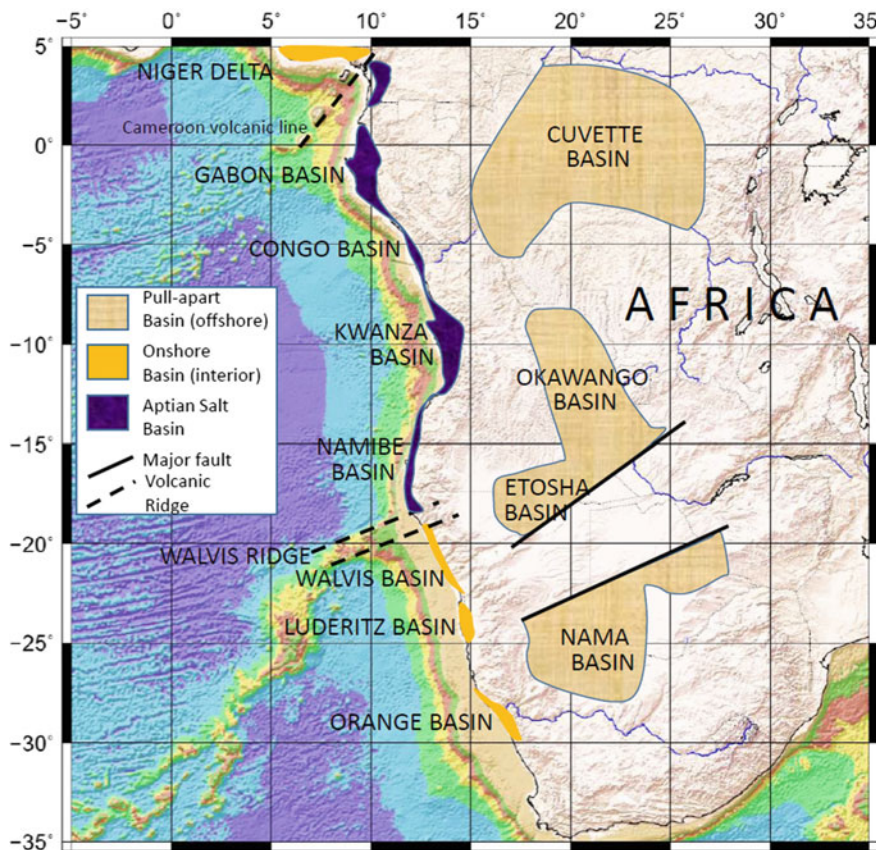


Fig. 8 Structural elements map of the West Africa basins

4131 m was drilled for Zohr 1X NFW and had around 630 m of hydrocarbon column out of which 410 m were the net pay (Nikolaou 2016). The reservoir is Miocene age carbonate Reef and has very good reservoir parameters. Digging deep into a bit of geology, it was understood that the geological evolution and tectonic history of Eratosthenes carbonate platform, is the main reason for the existence of Zohr field. As per press release of ENI, “The discovery, after its full development, will be able to ensure satisfying Egypt’s natural gas demand for decades”. As of Dec 20th, 2017; the first gas started flowing from the supergiant Zohr field in record time. No wonder that the Zohr discovery was a game-changer for the region and it indeed opened up a new play (Fig. 9).

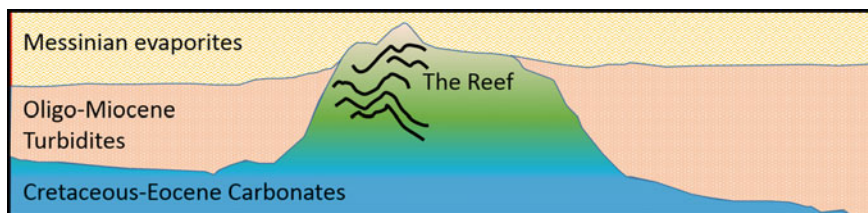


Fig. 9 Geological section of the Zohr discovery

8 Conclusions

Lula (Tupi) pre-salt oil field was discovered because with the advancement of technology it is now possible to see beneath salt in the seismic data. And also, because the geologists were able to understand the depositional environment. And also, because the reservoir engineers were able to understand the reservoir properties of Microbialite reservoirs. It has never been possible to work in silos and come up with an astounding result. Always a cooperative approach and integration of data have done wonders. So it did in Lula, Libra, Cameia and Zohr. Given the pace of advancement of technology and geoscientist's understanding of their respective domain, the day is not too far when the Lula, the Libra, the Cameia and the Zohr's will appear dwarfs on the worlds carbonate discovery map.

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Chapter 2

Conquering Carbonate Complexities: Understanding Geological Processes that Control Poro-Perm Relationships



K. Vasudevan

Abstract Carbonate reservoirs, although contain the lion's share of discovered In Place hydrocarbons globally, present the most complex challenges in reservoir characterization, accurate estimation of hydrocarbon volume and consequently in optimal field development planning and exploitation. The main causative of such complexities is the multi-scale heterogeneity in carbonate rocks that affect the rock fabric right from nanoscale to seismic scale, which renders any realistic modelling in spatio-temporal domain an arduous task. It has been observed that the porosity-permeability (poro-perm) relationship in carbonates does not exhibit any direct linear relationship contrary to siliciclastic reservoirs. Although it has been empirically demonstrated that reservoirs that have high depositional porosity (high energy carbonates) tend to have higher effective permeability, the complex diagenetic history, the natural compaction-induced fracturing at reservoir scale and tectonic-induced fracturing at the field scale, result in a very complex poro-perm relationship in most carbonate reservoirs. Added to this is the phenomenon of dual porosity-dual permeability reservoirs encountered in many carbonate reservoirs, makes the task even more challenging. The pore throat geometry and hence, the aspect ratio of pores in carbonates is very complex due to primary depositional control, various intrinsic and extrinsic factors, thermodynamic constraints, diagenetic potential and history and kinetic factors. The influence of Green House/Icehouse periods and the Milankovitch cycles on carbonate deposition imparts different sequence architecture and frequency of individual cycles resulting in large scale heterogeneities in the distribution of primary porosities. The diagenetic overprint on the primary rock fabric further renders the reservoir more complex. Thus, the poro-perm preservation, enhancement or reduction can be understood by unravelling the depositional cyclicity and the diagenetic overprint. Wherever well-preserved cores are available, this task can be accomplished relatively easily, but in cases where the data set are sparse as is often the case, the Gamma-ray and effective porosity logs can be used to decipher both the primary depositional cyclicity and the diagenetic cycles by using the detrending method. The analysis of Eocene, Oligocene and Miocene carbonates of several hydrocarbon fields of Mumbai Offshore basin has lucidly brought out the differing nature of Milankovitch cycles,

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the depositional versus diagenetic cyclicity and the impact on the poro-perm relationships in the spatial and temporal domain. It has been observed that carbonates deposited during Paleocene Eocene Thermal Maxima (PETM) exhibit relatively thick, high-amplitude–low-frequency carbonate cycles with low clay volume (often <20%) with diagenetic enhancement of porosity at the top of the cycles corresponding to the long exposure surfaces with destruction of porosity in the lower part of the cycles. The poro-perm relationship in these reservoirs exhibits a relatively direct linear relationship although moderate scatter is observed. In contrast, the Oligocene and Miocene carbonates have high-frequency low amplitude cycles with frequent thin shale layers followed by shallowing up Mudstone to Grainstone cycles often capped by uranium-rich high Gamma high resistivity carbonates representing exposure hard grounds. The Poro-perm relationship in these carbonates is much more complex resulting in a higher degree of heterogeneity in the distribution of speed zones, baffles and seals.

Keywords Poro-Perm relationship • Milankovitch cycles • Oligocene • Miocene carbonates • Mumbai Offshore

1 Introduction

Approximately 40% of present global hydrocarbon production comes from carbonate reservoirs and are expected to continue in future years also mainly owing to numerous giant fields of Middle-East. Therefore, understanding the carbonate reservoirs and produce them effectively is the prime challenge to global E&P industries. Deciphering the enigma of carbonate rock's complex pore space, permeability barrier and conduits behaviour are the key challenges that geoscientists face.

Extremity is the common feature of carbonates. Carbonate reservoirs can be gigantic though the majority of the pores being microscopic. In such a case, matrix permeability would be immensely low while the fractures would act like highway allowing fluid to flow through them. This makes carbonate rocks significantly different from siliciclastic reservoirs due to different depositional process, depositional environments and complex diagenetic history (Anselmetti and Eberli 1993; Lucia 1995, 1999). Shallow and deep marine areas, evaporitic basins, lakes, etc. are the places of carbonate deposits. Majority of the ancient carbonates formed in a marginal marine environment while the modern carbonates are widespread in the deep marine settings. Carbonates being chemically less stable, undergo intense cementation, dissolution, dolomitization, etc., as a consequence of a change in water depth, burial depth, temperature and pressure (Brie et al. 1985). Often, intense diagenetic alteration completely obliterates mineralogy and texture of the original framework, causing carbonates to exhibit varied porosity types, such as interparticle, intraframe, moldic, vuggy and micro-cracks or fractures. The prime hurdle of quantitative carbonate reservoir characterization is the identification of producible economic reserves and to distinguish it from non-recoverable reserves. The producibility can be better understood

from the permeability estimation which in turn is related to the complexity of the pore structures mentioned above (Anselmetti and Eberli 1993; Lucia 1995, 1999; Baechle et al. 2005; Baechle et al. 2007). Therefore, for the purpose of delineation of the sweet zone and flow properties determination, prediction of pore throat architecture from seismic and well log is utmost essential. Presence of varied types of pore structures in carbonates makes characterization a very complex process to accomplish. The modified response of rock physics parameters due to diagenetic effects and the presence of different clay minerals within pores escalate the complexity to a greater degree.

2 Factors Controlling Carbonate Deposition

Biological control over the carbonate deposition is overwhelming. Over 90% of deposited carbonate is of biological origin. Distribution and species assemblage of carbonate-secreting organisms have changed significantly through geological time. Since the character of carbonate rock depends heavily on its parental organisms, therefore, the character of carbonates also changes significantly through geological time.

Carbonate deposition is controlled by various factors like Bathymetry, Eustatic Sea Level Change, Turbulence of water, Ocean circulation, Nutrients, Climate belts, Global Atmosphere, Tectonic setting, Biological community, etc. Deviation from the normality of in any single factor leads to the cessation of deposition.

Water Temperature: Temperatures between 25 and 30 °C are optimum for carbonate deposition. Temperatures above 35 °C kill carbonate-secreting organisms. Since more than 30 °C temperature is rare in the open ocean, so the main influencing factor is the absence of cold water.

Water Depth: The depth to which carbonate-secreting organisms can thrive is a function of light penetration. Therefore, water depth coupled with light penetration governs the carbonate deposition. In exceptionally clear water this limit can be extended up to 100 m but for normal cases, it ranges between 70 and 80 m.

Turbulence in water: Organisms don't flourish in turbid waters. Turbidity impedes the light penetration thereby restricts the carbonate deposition.

Nutrients: Carbonate-secreting organisms need continuous nutrient supply. The abundance of planktons is governed by the open ocean current that carries nutrients in solution. Currents are thus favourable to carbonate deposition.

Salinity: Normal salinity is required for carbonate growth. Organisms live within the salinity range 27–40‰. Carbonate deposition is stopped by great floods of fresh water sweeping over them from land killing the organisms.

3 Carbonate Uniqueness

Carbonates and siliciclastic rocks are diametrically opposite to each other. Compositionally siliciclastic rocks are polymineralic, silica being the primary constituent, whereas carbonates are mono-mineralic or bi-mineralic (mineral composition is restricted to calcite/aragonite, dolomite, gypsum and evaporite minerals/anhydrite) only. Majority of carbonates rocks are in situ and having biological origin whereas siliciclastic rocks are having a mechanical origin and may have travelled thousands of kilometres from source before deposition. Mono-mineralic carbonates are vested with the complexity of multiple order starting from scale-dependent to petrographic to petrophysical. Key challenges associated with carbonates are complex multi-scale heterogeneity, low porosity-permeability correlation, complex sonic velocity, V_p/V_s , porosity relationship-pore size and types, wettability related issues, fracture compartmentalization impact, etc.

Unlike siliciclastics, pore architecture in carbonates are very complex and often shows polymodal pore systems. Presence of polymodal pore systems makes the petrophysical evaluation very difficult. It is often found that there exists no relationship between porosity and permeability which cumulated to give rise big difference between storage and flow capacity. Moreover, non-correlation in both numerical and spatial domain makes the job of model preparation a real nightmare.

Diagenesis plays havoc in case of carbonate. This is the single most significant difference between siliciclastic and carbonate systems. Almost all the carbonate rocks undergo diagenetic changes but the impact of diagenesis may be variable. Diagenesis can invert primary depositional texture and completely reorganize the pore network system. The impact of diagenesis on petrophysical properties and dynamic flow properties is still uncertain and poorly understood. The petrophysical response of two identical rocks but with different diagenetic episode can be extremely different. Two identical oolitic grains of sand subjected to two opposite diagenetic episode, e.g. early compaction followed by cementation and on the other hand, early cementation followed by compaction will have totally different contact architecture and hence have a differing response to P-wave velocity (Brigaud et al. 2010). The rock which has undergone early compaction will have grain to grain contact even after cementation. Therefore, P-wave velocity will be higher in this case. On the other hand, the rock which underwent early cementation will have cement between the two grains in all cases even after cementation. Cement acts as a cushion during the P-wave propagation and dampens its velocity. Therefore, P-wave velocity will be lower in this case.

The porosity-permeability relationship in carbonate is very complex. Different facies can have similar petrophysical, hydrodynamic properties while similar facies can have widely different properties. For a given porosity, a wide range of permeability is possible. High porous carbonates (>30%) often have negligible permeability (<1 mD) since micropores or disconnected moldic/vuggy porosity form a dominant porous network. Moderate porosity carbonates (15–20%) often have excellent permeability (>100 mD) because of well-connected pore network, e.g. via secondary

pores and fractures. Extremely low porous (2–4%) carbonates may have good permeability because of well-connected fractures (Karst breccia).

Carbonates have low sonic/density contrast between the reservoir and sealing unit. Velocity in carbonate is a function of the dominant pore types and total porosity. There exists Inverse porosity velocity relationship but significantly deviated due to dolomitization and presence of various pore types. Frame forming pore types such as moldic/vuggy porosity have significantly higher velocity at equal porosities compared to interparticle/micro/fracture porosity (Xu and Payne 2009). The validity of Gassmann fluid substitution in carbonates is uncertain owing to the complex presence of different pore system and multi-scale heterogeneity.

4 Porosity-Permeability Relationship

Porosity-Permeability distribution is a very critical factor in reservoir characterization. This distribution plays a significant role in determining completion strategies for the implementation of water flooding program, construction of simulation model (Shirer et al. 1978; Chopra et al. 1989). Each microfacies as per Dunham classification clearly demonstrate a different poro-perm relationship (Dunham 1962).

Matrix-supported facies such as mudstone, wackestone shows little correlation of porosity with permeability. Grain supported facies shows linear poro-perm relationship but subjected to diagenetic changes. Diagenesis acts in both ways. It can both increase or decrease the poro-perm relationship. Progressive compaction and cementation destroy both storage and flow capacity but leaching and fracturing works in the opposite way. Grain leaching increases the porosity but cement leaching and fracturing increase the permeability. Dolomitization can affect the poro-perm relation in a great way. A global study of limestone and dolostone indicates that (Ehrenberg et al. 2006), in deep-buried platforms average porosity in limestone is much lower than associated dolostones, but average permeability hardly differs for given porosity. But in shallow buried platforms the scenarios is totally reversed. Average porosity does not differ much for limestone and dolostone but there is a huge difference in average permeability, dolostones being more permeable. With an increase in burial depth, there is hardly any reduction of porosity in carbonates but in clastics the reduction is considerable.

Classically permeability is determined from porosity using Eq. (1)

$$\ln k = a\varphi + b \quad (1)$$

where k is permeability, φ is the porosity, a and b are arbitrary constants.

However, this equation is often based on statistically insignificant data sets and lacks theoretical background. A linear relationship between logarithms of porosity and permeability is assumed because it appears that permeability is log-normally distributed over the space but the correlation between two parameters may not show any relationship. Theoretically, porosity is independent of grain size but permeability

is strongly inversely proportional to grain size. The plot of porosity versus log permeability may indicate linear relationship but there remains very high and very low permeability zone within the same porosity level. The plot of porosity and permeability of all data contained from the routine core analysis of the cores retrieved from the NBP field of ONGC (Fig. 1) elucidates this complex poro-perm relationship. The present context exhibited clearly in the plot. If we take 10% porosity value, the variation of permeability ranges from 0.01 to 100 md.

Therefore, the estimation of accurate permeability from porosity data cannot be made from the traditional approach. There exist various alternative models for porosity-permeability transform, proposed by several authors (Timur 1968; Dubrule and Haldorsen 1986; Stiles and Hutfilz 1992; Dorfman et al. 1990) but lack theoretical background. Hence for any given rock type, the different relationships estimated for porosity and permeability are suggestive of the manifestation of different hydraulic units (Hearn et al. 1984; Slatt and Hopkins 1990).

Hydraulic Unit (HU) is the characteristic part of the reservoir facies within which the geological and petrophysical properties that influence the fluid movement are consistent within but different from the other rock facies while comparing on similar properties. Therefore, hydraulic flow unit (HU) is a part of the reservoir that has both lateral and vertical extension and with similar flow and geologic characteristics (Hearn et al. 1984). As already discussed pore geometry is the prime influencer of fluid flow through porous media. Pore throat attribute, in turn, is dependent on mineralogy (type, abundance, location) and texture (grain size, grain shape, sorting

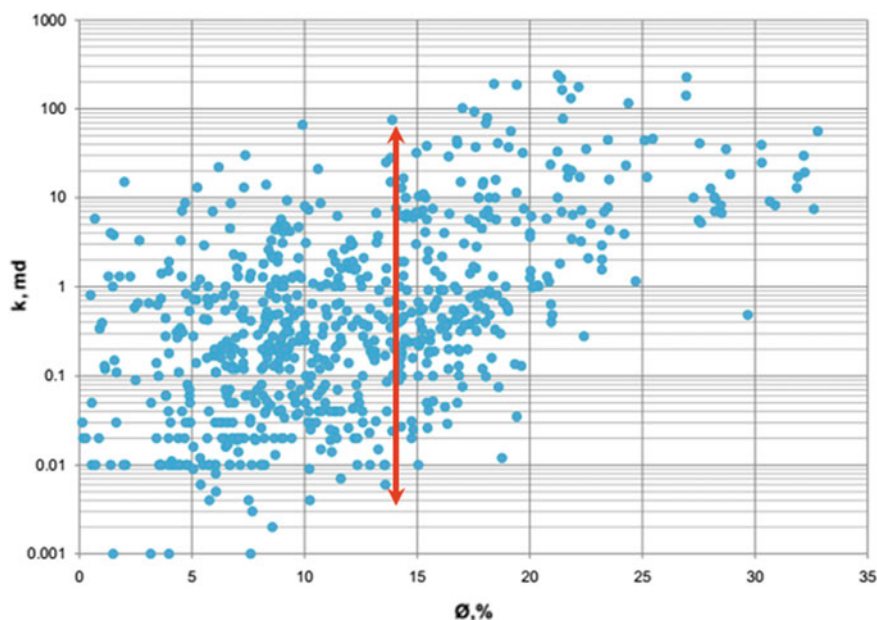


Fig. 1 Poro-perm relationship from cores of NBP field of ONGC