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Unconventional Shale Gas Exploration and Exploitation

Current Trends in Shale Gas Exploitation

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Preface

"Unconventional Shale Gas Exploration and Exploitation" delves into the intricacies of a rapidly evolving sector within the energy landscape. This book serves as a comprehensive guide, offering insights into the multifaceted aspects of shale gas exploration and exploitation, showcasing the cutting-edge techniques and emerging trends reshaping this dynamic field.

The term "unconventional resources" refers to the hydrocarbon deposits requires improving technologies to develop at a commercial scale, for example: unconventional resources are shale gas, shale oil, tight oil, tight gas, heavy oil, shales, gas hydrates, and coalbed methane. Unlike the conventional reservoirs, the unconventional reservoirs are huge in volume but there are lot of challenges to explore those resources. Unconventional reservoirs are uncertain, and difficult to determine with a high degree of accuracy. However, the advanced technologies development can produce, and develop unconventional reservoirs. The steady decline of conventional oil and immense quantity of unconventional hydrocarbon resources, expected to continue development to be the future. Unconventional gas includes shale gas, tight gas, coal bed methane (CBM) and gas hydrate, are of approximately (800–6521) $\times$ 1012 m3. The unconventional gas resources are 1.7–13.8 times greater than that of the total amount of conventional gas resources. This indicates that the possibility of unconventional hydrocarbon resources is far beyond that of conventional resources, which also remarks a great future of unconventional resources in bridging the global energy demand. The hydrocarbon reservoirs which are generally too difficult to develop, and require large stimulation treatments to produce economical volume of hydrocarbons are referred as unconventional reservoirs. Coal Bed Methane (CBM), Shales, Natural Gas Hydrates, Tight Oil and Gas, Heavy Oil are some of the unconventional resources of oil and gas, which are many times larger in volume as compare to the conventional oil and gas reserves. As these resource are difficult to extract from the subsurface, in order to develop an unconventional reservoir economically, it requires proper strategizing and increased pricing. The unconventional reservoirs are quite complex resulting in less accurate information about the reservoir parameters. Additionally, the results from the individual wells are often inconclusive and costly. The unconventional deposits extend over large areas, and are independent of the geological structures of that region. Economics of unconventional beds and risk analysis are two main parameters which are considered for successful development of these reservoirs. The development of these resources is very capital-intensive. As the efficiency of the industrial operations increase, the problems associated with these reserves can be analysed with greater efficiency.

The first commercial shale gas well was drilled in 1821, at Fredonia, New York. The shale gas was produced from the Devonian Fredonia Shale Formation. After that the success of Barnett Shale in Texas caused a fast spread in research of the shale gas reserves. The interest about Shale exploration had spread across countries like United States, Canada, Europe, Asia and Australia. San Juan Basin of New Mexico, Barnett Shales from Fort Worth Basin at Texas, Antrim Shale of Michigan, and Appalachian/Ohio Shales are the major contributors to the US shale gas production. The worldwide shale gas production is led by North America. Beyond US and Canada, commercial levels of shale gas could be extracted in Argentina, China, India. Even though the shale reserves of many nations may seem to have huge potential yet exploration could not be carried out successfully due to the several economic, environmental, technical and social issues.

The chapters curated in this volume represent a collaborative effort by experts and practitioners deeply entrenched in the realms of shale gas exploration, reservoir characterization, well logging techniques, unconventional energy potential, and geopolitical implications. Each chapter is designed to unravel specific facets, from evaluating thermal maturity to reservoir characterization and the latest advancements in well logging technologies. Chapter "Emerging Techniques for Evaluating Thermal Maturity in Shale Gas Systems" explores emerging techniques for evaluating thermal maturity in shale gas systems, essential for gauging the potential yield of these unconventional resources. Shale gas is the insitu hydrocarbon gas present within the shale sedimentary rocks and may be present as free gas or adsorbed gas or both. These are generated by their thermal alteration of kerogen, the primary component of organic matter which is insoluble in organic solvent. Hydrocarbon generated inside the shale, known as source rock. The source rock gets converted into oil or gas depending upon the nature of organic matter. Chapter "Shale Gas Reservoir Characterization: Understanding the Shale Types and Storage Mechanisms for Effective Exploration and Production" dives into shale gas reservoir characterization, illuminating the diverse shale types and storage mechanisms critical for effective exploration and production strategies. Although, the shale rocks act as a both source and reservoir rock for the shale gas, they are finally recovered through hydraulic fracturing techniques, including acidization, propane injection, Co2 fracturing, and other techniques. Chapters "Advances in Well Logging Techniques for Shale Reservoirs Exploration" and "Recent Advances in Well Logging Techniques for Exploration of Shale Reservoirs" traverse the terrain of advanced well logging techniques, showcasing the evolving methodologies instrumental in enhancing exploration efficiency and reservoir evaluation. Petrophysical well logging methods play crucial role in shale reservoirs assessment. Every logging method has its own advantages and limitations. Chapters "Advances in Well Logging Techniques for Shale Reservoirs Exploration" & "Recent Advances in Well Logging Techniques for Exploration of Shale Reservoirs" discuss the applications and limitations of the standard well logging methods as well as advanced technique like nuclear magnetic resonance (NMR) in shale reservoirs. The chapter also described how to estimation of total porosity, saturation, total organic carbon (TOC), brittleness index (BI) and velocity anisotropy will also be explained. The purpose of this chapter is to guide future academic research and exploration, development and production projects of hydrocarbon bearing shale reservoirs to identify the best logging methods and the interpretation models to be applicable to the respective shale formation. Chapter "Recent Advances in Well Logging Techniques for Exploration of Shale Reservoirs" discusses about the application of advanced logs in the successful exploitation, understanding and evaluation of shale reservoirs. Estimation of parameters related to source quality (SQ), reservoir quality (RQ), and completion quality (CQ) are crucial in the evaluation of a shale reservoir for commercial success. Advanced well log techniques can help in understanding these parameters. This chapter discusses some of the advanced well logging tools and their applications.

The chapter "Shale Gas potential in Indian Sedimentary Basins" identified five onland Sedimentary basins with potential shale gas accumulations. They are: Cambay basin, Gondwana basin, Assam-Arakan Basin, Krishna-Godavari Basin and Cauvery basin. The regional geology, stratigraphy with shale thickness, tectonic setup and important parameters of Total Organic Carbon content (TOC), Vitrinite Reflectance (Vro), Gas Concentrations and Kerogen type are discussed for each of these basins.

Chapter "Emerging Unconventional Energy Resources Shale Gas Potential in Indian Sedimentary Basins" discusses about the improved gas recovery methods applicable to shale reservoirs. In the first portion, it gives a detailed explanation on shale and enhanced gas recovery (EGR), and then it discusses the characteristics and flow behavior of shale gas in the second section. Both the continuous CO2 injection approach and the huff-n-puff CO2 injection technique are reviewed in relation to the mechanism of enhanced gas recovery as well as the problems that were faced during the process of gas recovery.

The chapter "Shale Gas Developments & Challenges in India: Legal Regulations & Way Forward" to analyze the policy and legal status & reforms in the unconventional sector. The rapid rise in the production of Gas from shales in the US has led to renewed interest in unconventional gas sources globally. From virtually nil production in the year 2000 in US, shale gas production has reached a level of 23% in 2010 and is expected to comprise nearly half of the total natural gas supply by 2035. India's recent upstream Sector policy reforms in HELP & OLAP licensing regime from 2015-18 have also boosted the exploitation of unconventional Shale Gas resources in Indian sedimentary basins. It needs to build an unconventional industry ecosystem aligned with United States's robust drilling & hydrofracking ecosystem of Shale Gas Industry. This chapter is to recognize challenges in India and draw lessons from United States Unconventional Industry and from other nations like Canada, China.

This book is not just a compendium of knowledge; it is a compass guiding scholars, researchers, industry professionals, policymakers, and enthusiasts through the labyrinth of unconventional shale gas exploration and exploitation. It aspires to ignite discussions, inspire innovations, and pave the way for a sustainable and efficient utilization of this transformative energy resource.

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Emerging Techniques for Evaluating Thermal Maturity in Shale Gas Systems

Devleena Mani and Nihar Ranjan Kar

Abstract

Gas shale reservoirs, characterized by their extensive unconventional dimensions, are prime targets for source rock characterization studies. Understanding the properties and hydrocarbon generation potential of these self-contained systems is crucial for effective exploration and development. This article presents a critical review of various techniques employed in determining thermal maturity, a key parameter in source rock characterization. Additionally, recent developments in studying thermally altered bitumen (pyrobitumen) are explored, showcasing its potential as an indicator for petroleum generation and migration. These advancements pave the way for enhanced accuracy in kinetic models, enabling more precise forecasts of hydrocarbon generation within these complex gas shale reservoirs.

Keywords

Organic matter · Thermal maturity · Tmax · Scanned electron microscopy · Transmission electron microscopy

1 Introduction

The organic matter (OM) produced from once living organisms gets accumulated and buried over time in sediments and is subjected to geological processes that result in the formation of complex geopolymer kerogen. The thermal degradation of kerogen results in formation of hydrocarbons such as oil and gas. In hydrocarbon exploratory studies, establishing a pod of active or potential source rock is critical. This involves characterizing the abundance and type of organic matter, its thermal maturity along with the environment of deposition (Kar et al. 2022). These properties of organic rich rocks help to determine their potential for generating the hydrocarbons (Killops and Killops 2013). Source rocks containing high-quality organic materials, for example, are more likely to produce light and pure crude oil; whereas that with low-quality organic matter may generate heavy and sour crude oil, including natural gas. As a result, characterisation of source rocks assists in identifying possible hydrocarbon sources that are most likely to deliver commercially viable resources. This information is critical for the oil

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and gas industry in order to determine the feasibility of exploration and production activities in a particular location.

Depending on the geological and redox conditions of sedimentation, only a small proportion of organic matter—about 0.1%—gets retained in sediments (Mani et al. 2022). Post-sedimentation processes of OM degradation and preservation differ from environment to environment. For example, a marine anoxic depositional environment will have a better preservation history than a terrestrial oxic environment. High organic productivity, increased nutrient levels and upwelling lead to greater production of OM. In reducing environments with restricted water circulation and absence of bioturbation, OM gets preserved along with the fine-grained sediment particles, mostly <2 µm, due to similar hydrodynamic nature (Bjørlykke 2015; Mani et al. 2022). A simple flowchart of the composition of sedimentary organic matter is given in Fig. 1. Besides generation potential, the OM characterisation provides information about the geological history and depositional environment of a specific source rock (Killops and Killops 2013). Geologists can reconstruct the paleoenvironmental conditions that prevailed during sedimentary basin deposition by studying the organic matter concentration and composition of source rocks. This information is useful for understanding the basin's structural and tectonic history, as well as in estimating the distribution and grade of hydrocarbons within the basin (Killops and Killops 2013).

The organic matter in any rock consists of two components, namely, the kerogen and the bitumen. The kerogen is the macroscopic, disseminated complex geopolymer in source rocks. It is formed during catagenetic processes in the subsurface. The bitumen (biomarkers) consists largely of lipids of organisms transferred to the rocks with minimal diagenetic alterations. A systematic approach adopted for source rock characterization includes estimating the following parameters:

- Organic matter concentration: It is the total organic carbon (TOC) content in any rock. TOC can be measured using elemental analysis, pyrolysis, and Rock–Eval pyrolysis.

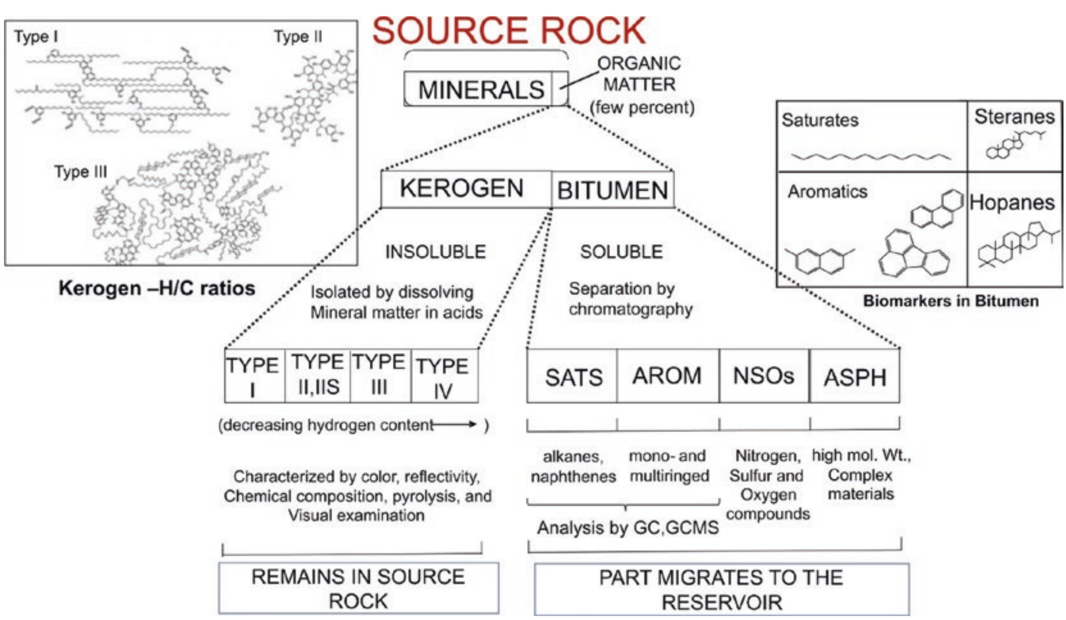

Fig. 1 Composition of sedimentary organic matter (modified after Mani et al. 2022)

In an elemental analysis, the rock sample is treated with acid to dissolve any inorganic carbonates that might affect the TOC result, and then the carbon content of the sample is assessed using an elemental analyzer. Pyrolysis involves heating the rock sample to release organic compounds, which are then measured using a gas chromatograph. It provides information on the type and quantity of organic compounds present in the sample, in addition to the TOC content. Similar method include Rock–Eval pyrolysis, which involves heating a rock sample to different temperatures to measure the different properties of source rock. In addition to TOC, rock–eval pyrolysis provides information regarding its maturity, type of OM and its hydrocarbon generation potential, which helps to characterize a source rock.

- Organic matter type and quality: It involves determining the type and quality of kerogen present in the rock. This is accomplished by the use of several methods such as Rock–Eval pyrolysis, gas chromatography-mass spectrometry (GC–MS), and Fourier transform infrared (FTIR) spectroscopy on rock samples.
- Thermal maturity: The thermal maturity of organic matter is a critical factor in determining the type and quality of hydrocarbons that can be produced. This is measured by measuring the vitrinite reflectance, which is the quantity of light reflected by heated organic matter. Rock Eval pyrolysis also provides the thermal maturity of sedimentary organic matter.
- Petrographic analysis: Petrography involves examination of rock samples under a microscope to assess their composition and texture. This information can be used to analyse the depositional environment and diagenetic history of source rock.
- Grain size analysis: Grain size analysis is the process of determining the size distribution of mineral grains in a rock. This information is significant in assessing the depositional environment as well as the degree of grain sorting and rounding.
- Rock properties: To determine the reservoir quality of the rock, several physical parameters of the rock, such as porosity, permeability, and compressive strength, are also studied.
- Isotope analysis: It helps to categorize the type of OM and depositional environment.
- Biomarker analysis: It helps in determining the type of OM input, depositional environment and thermal maturity of source rocks.
- Hydrocarbon potential: Eventually, all of the data gathered from the different analyses is utilised to determine the source rock's hydrocarbon potential in light of basinal studies to assess the type and quality of hydrocarbon that can be produced.

In this communication, the importance of thermal maturity studies for source rock characterisation, in addition to the various approaches employed to determine it are discussed.

2 Thermal Maturity of Source Rocks

In sedimentary basins, organic matter is the principal source of hydrocarbons (Tissot and Welte 1984). Organic matter undergoes a number of chemical and physical modifications when it is deposited and buried, following the generation and expulsion of hydrocarbons. Temperature, pressure, and burial depth, all have an impact on the degree of change that organic matter goes through, known as thermal maturity (Hunt 1995). Evaluating the thermal maturity is an critical to source rock characterisation in the oil and gas industry as it determines the production state of a source rock/kerogen by assessing its state in terms of thermally immature, mature, or over-mature.

Understanding of source rock thermal maturity is important in order to understand the following:

- To assess the quality and calculate the amount of hydrocarbons in the source rock. The amount of hydrocarbons that gets generated from OM increases as the thermal maturity of the source rock rises (Espitalie et al. 1987).

- The time and amount of hydrocarbon production in the source rock may be assessed using thermal maturity studies. These data may be utilised to develop and improve exploration and production plans, such as well location and drilling targets (Magoon and Dow 1991).
- The tectonic history and burial development of the sedimentary basin can be better understood by thermal maturity studies. Geologists can reconstruct the history of sedimentation and tectonic activity by analysing the thermal maturity of source rocks in various basin areas (Hunt 1995).

3 Common Techniques Used for Thermal Maturity Study

3.1 Rock–Eval Pyrolysis

Rock–Eval pyrolysis is a sophisticated instrument commonly used for bulk rock analysis. The technique involves heating a rock sample in a controlled environment and measuring the amount of hydrocarbons that are released as a function of temperature (Kar et al. 2022). The Tmax value, the temperature at which maximum amount of kerogen cracks to produce hydrocarbon, determines the maturity condition of source rock (Tables 1 and 3). Along with maturity, this study provides additional parameters including TOC, hydrogen index (HI), oxygen index (OI), hydrocarbon generation potential of source rock (marked by S2 peak), amount of free hydrocarbon (S1) that aids in a better characterization of kerogen (Table 2) (Espitalie et al. 1987; Kar et al. 2022). Computed vitrinite reflectance value (%EVRo) can be calculated by using rock–eval Tmax data using the following equation given by Jarvie (1991). This %EVRo value can also be used to determine the thermal maturity stage of the source rock.

$$\%\mathrm{EVRo} = (0.0180 * \mathrm{Tmax}) - 7.16.$$

Table 1 Relationship between Rock–Eval pyrolysis Tmax and hydrocarbon generation zone. Modified after AAPG wiki

Rock–Eval pyrolysis Tmax (in °c)	Hydrocarbon generation zone
<435	Immature
435–455	Oil (from type II kerogen)
435–465	Oil (from type III kerogen)
>455	Gas (from type II kerogen)
>465	Gas (from type III kerogen)

Table 2 Rock–Eval parameters used to distinguish between kerogen type and expelled product quality upon maturation

Kerogen (quality)	Hydrogen index (mg hydrocarbon/g TOC)	S2/S3	Atomic H/C	Mean product at peak maturity
I	>600	>15	>1.5	Oil
II	300–600	10–15	1.2–1.5	Oil
II/III	200–300	5–10	1.0–1.2	Oil/gas
III	50–200	1–5	0.7–1.0	Gas
IV	<50	<1	<0.7	None

Modified after Peters et al. (2005a)

3.2 Organic Petrography

Organic petrography is a valuable technique for assessing the thermal maturity of source rocks. It entails identifying, categorizing, and distributing organic particles inside the rock and gives a clear picture of the level of organic matter alteration that has taken place (Hunt 1995). Vitrinite reflectance, a crucial factor in defining thermal maturity, may be precisely measured due to organic petrography. Also, it makes it possible to distinguish between various forms of organic materials, such as terrestrial and marine ones, which can assist provide light on the depositional environment of the source rock. According to Hunt (1995), organic petrography is one of the most crucial techniques for measuring the thermal maturity of organic materials in sedimentary rocks.

Vitrinite reflectance

In the petroleum industry, the vitrinite reflectance is frequently used to assess the thermal

Table 3 correlation between the maturity of OM, Thermal Alteration Index (TAI), Tmax and vitrinite reflectance

Maturity	R_o (%)	Tmax (°c)	TAI
Immature	0.20–0.60	<435	1.5–2.6
Early mature	0.60–0.65	435–445	2.6–2.7
Peak mature	0.65–0.90	445–450	2.7–2.9
Late mature	0.90–1.35	450–470	2.9–3.3
Post mature	>1.35	>470	>3.3

Modified from Peters and Cassa (1994); Peters et al. (2005a)

maturity of source rocks (Taylor et al. 1998). When the temperature and pressure, to which the rock has been exposed, rises, vitrinite, a type of maceral found in organic materials, becomes more reflective. This increase in reflectance is a result of the chemical and physical changes that occur during the maturation of OM. Vitrinite reflectance is an important factor in the assessment of source rocks because it offers a quantitative estimate of the level of thermal maturity (Espitalie et al. 1987). More developed organic matter has a larger potential for producing hydrocarbons, and this is shown by increased vitrinite reflectance. Many studies have demonstrated the use of vitrinite reflectance in the determination of the thermal maturity of source rocks (Table 3) (e.g., Peters and Cassa 1994).

Fluorescence microscopy

This method includes examining fluorescent organic elements found in the rock matrix, particularly vitrinite and solid bitumen (Oehler and Cady 2014). The amount of thermal maturity of the source rock may be inferred from the fluorescence characteristics of this organic matter. For instance, the fluorescence intensity of solid bitumen increases as temperature rises, whereas the fluorescence intensity of vitrinite decreases. Fluorescence microscopy may also be used to detect the presence of other organic components, such as alginite, an organic substance made from algae. The presence of alginite can reveal the depositional setting of the source rock and offer crucial details on its origin and potential for producing hydrocarbons (Stasiuk 1999). Additionally, this method is also non-destructive, enabling repeated examinations of the same sample.

3.3 Spore Coloration

The colour of the spores can be used to assess the thermal maturity of the source rocks. The colour of the spores of mature organic matter shifts from light to black, suggesting a rise in thermal maturity (Table 4) (Marshall 1990). The conversion of organic matter into hydrocarbons at higher temperatures and pressures is what causes the shift in spore pigment. Spore colour may be identified and analysed to reveal important details about the thermal history of parent rock and its capacity to produce hydrocarbons (Marshall 1990). Spore coloration has been employed in several research as a technique for analysing thermal maturity.

3.4 Thermal Alteration Index (TAI)

An important method for assessing the thermal maturity of source rock is the thermal alteration index (TAI). TAI is based on the visual observation of variations in the colour, texture, and reflectivity of minerals under increasing thermal

Table 4 Pollen and spore colour variations, together with the Spore Colour Index (SCI)

Spore colour	SCI
Pale Yellow	1
Pale yellow-lemon yellow	2
Lemon yellow	3
Golden yellow	4
Yellow orange	5
Orange	6
Orange brown	7
Dark brown	8
Brown-black	9
Black	10

Modified from Marshall (1990), Njoh Olivier and Atud (2017)

Table 5 Correlation between the Thermal Alteration Index (TAI), hydrocarbon production zones/maturity, and colour changes in spores and pollen

Spore ad pollen colour	Thermal alteration index (TAI)	Petroleum generation/ maturity
Pale yellow-yellow	1	Immature kerogen
Yellow to light orange-medium orange	2	Oil window
Dark brown	3	Gas window
Brownish black to black colour	4	Wet gas limit-dry gas limit
Vitreous black- fossils brittle	5	Dry gas preservation limit

Modified from Marshall (1990), Utting and Hamblin (1991), Njoh Olivier and Atud (2017)

stress, such as vitrinite (Table 5) (Marshall 1990; Utting and Hamblin 1991). For a more comprehensive evaluation of thermal maturity, TAI is frequently combined with vitrinite reflectance measurements. TAI is advantageous than other approaches as it offers a qualitative evaluation of thermal maturity. For instance, it doesn't need specialist equipment or sample preparation, is rapid and affordable (Njoh Olivier and Atud 2017). TAI may also offer data on a thermal history of source rock, which is important for comprehending petroleum systems (Marshall 1990; Utting and Hamblin 1991).

3.5 Apatite Fission Track Thermochronology

It measures the build-up of damage tracks in apatite minerals brought on by the slow decay of uranium and thorium isotopes. The tracks are annealed as the rock is heated, and new tracks are created when the rock cools. Researchers may ascertain the date and duration of heating episodes by examining the distribution of track lengths, and this information can reveal information on the thermal maturity of the source rock (Burtner et al. 1994). AFT has been effectively utilised to estimate the thermal histories of sedimentary basins in a range of contexts, including offshore sedimentary basins, rift basins, and foreland basins. The method has also been applied to pinpoint the date of uplift and erosion in sedimentary basins, which can provide crucial details about a region's tectonic development.

3.6 Time–Temperature Index (TTI)

The Time–Temperature Index (TTI) is an important technique for estimating the thermal maturity of source rocks. The rate and extent of hydrocarbon formation with rising temperature and duration are predicted using the Arrhenius equation and the kinetic data for hydrocarbon generation (Lopatin 1971). TTI is frequently used with other geochemical and petrographic methods to assess the potential of source rocks and establish the ideal depth for hydrocarbon exploration. TTI is one of the most popular techniques for evaluating thermal maturity, and the result of TTI calculations are regularly contrasted with other maturity indicators to offer further confidence in the estimations of the thermal history of a sedimentary basin (Peters and Cassa 1994). The TTI may also be used to anticipate the composition and quantity of created hydrocarbons as well as the time of hydrocarbon production events.

3.7 Raman Spectroscopy

Raman spectroscopy is a non-destructive technique that is used to identify and quantify the organic and inorganic components of rocks. It is a crucial tool to assess the thermal maturity of the source rock, since it provides details about the chemical make-up and structural alterations that take place throughout maturation (Fig. 2) (Henry et al. 2019). Raman spectroscopy can identify changes in the aromaticity and carbon–carbon double bond of organic molecules, which may be used to assess the degree of thermal modification of the source rock. Moreover,

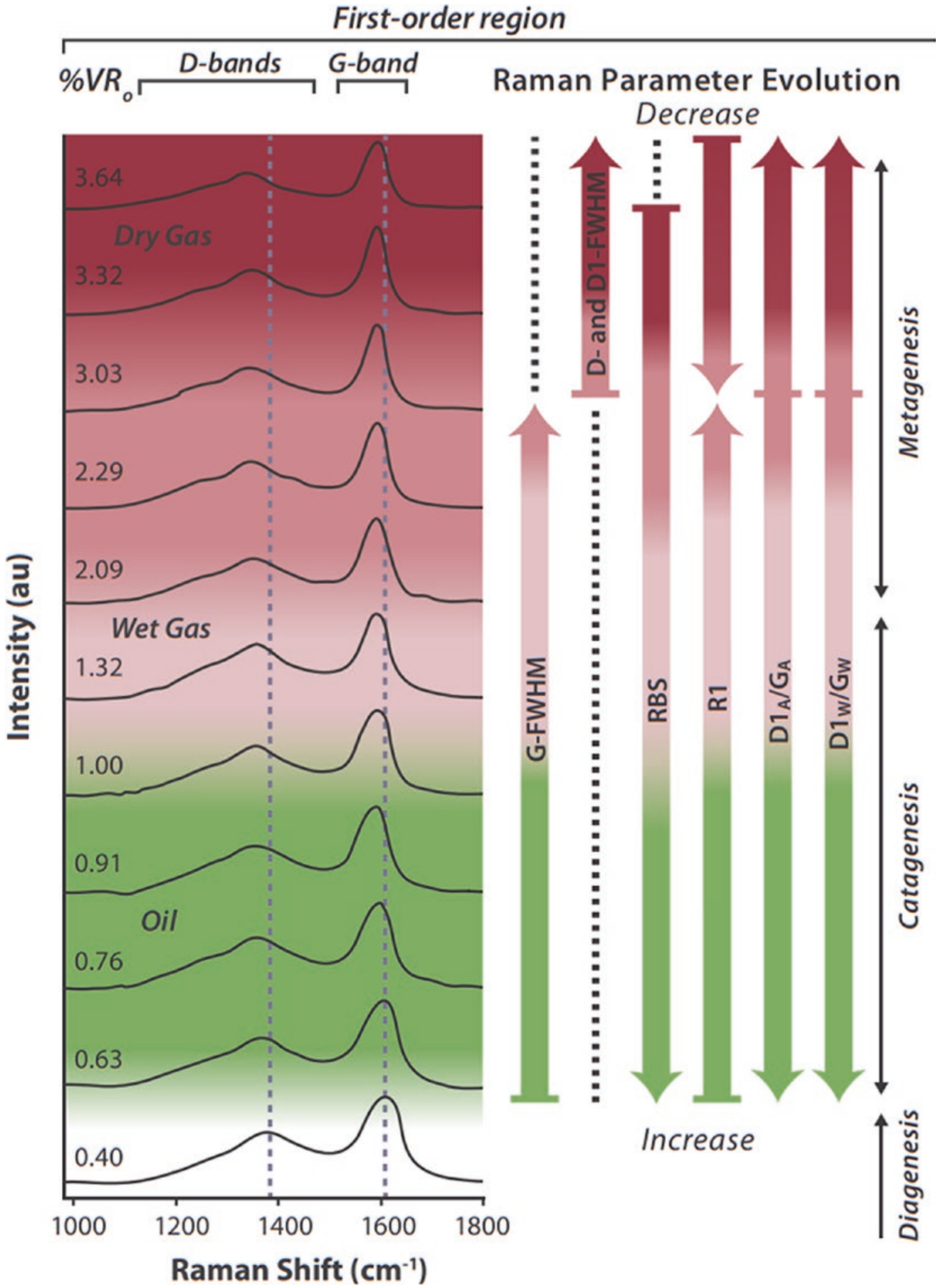

Fig. 2 Figure showing the effects of increasing VRo on the Raman spectra of OM and its characteristics (modified after Henry et al. 2019)

it may be used to recognise and measure minerals like pyrite, carbonates, and clays that occur during diagenesis and maturation. Raman spectroscopy has developed into a potent technique for the investigation of organic materials in sedimentary rocks (Henry et al. 2019). It has been applied to research how kerogen alters structurally during thermal maturation and how metamorphic rocks create graphite. The existence of other forms of carbon, including amorphous, diamond-like, and graphitic carbon, has also been detected using Raman spectroscopy. These carbon types can reveal crucial details regarding the origin and maturation of source rock.

3.8 X-Ray Diffraction (XRD)

It is very helpful for figuring out the mineral composition of source rock, which can reveal information about the thermal maturity and hydrocarbon potential of source rocks. Based on the distinctive diffraction patterns of the crystalline phases found in a sample, XRD may be used to estimate the amounts of minerals including clay, quartz, and feldspar. The degree of diagenesis and the thermal maturity of the source rock may then be determined using this information (Mani et al. 2015). It is an important technique for locating probable source rocks and evaluating their capacity to produce hydrocarbons. By determining the presence of minerals like calcite and dolomite, which can alter porosity and permeability, it can also be used to assess the potential reservoir quality of rocks.

3.9 Fourier Transform Infrared Spectroscopy (FTIR)

By measuring the infrared radiation absorption by organic functional groups in the rock, the FTIR approach can give details about the composition and structure of organic materials. The thermal maturity of the source rock may be determined by using FTIR to detect the presence of particular functional groups in the rock, such as aliphatic, aromatic, and carboxyl groups (Berthonneau et al. 2016). To assess the thermal maturity of source rocks from diverse sedimentary basins across the world, FTIR has been employed. For instance, the robust correlation typically observed between FTIR parameters and R_o or the H/C elemental ratio provides compelling support for employing FTIR indices as indicators of thermal maturity in Devonian black shales from Illinois and Western Canada Sedimentary Basin (Lis et al. 2005).

3.10 Carbon Isotopes

The quality of the organic matter and its thermal maturity in the source rocks can be evaluated using the ratio of stable carbon isotopes ($\delta^{13}C$) (Mani et al. 2015). The carbon isotopic composition of the OM and the degree of thermal change are strongly correlated, with enriched values of $\delta^{13}C$ indicating greater thermal maturity. Also, the source of organic materials and the depositional environment can both be identified by the carbon isotope analysis (Rullkötter 2001). The capacity to evaluate small quantities of organic matter is one of the benefits of carbon isotope analysis, making it a useful technique for determining thermal maturity in samples with little organic matter concentration.

3.11 Confocal Laser Scanning Microscopy (CLSM)

Confocal laser scanning microscopy (CLSM) is an effective method that may be used to look at the microscale characteristics of organic content in source rocks (Schopf et al. 2006). It may give details on the porosity and permeability of different organic matter components, including vitrinite, solid bitumen, and different types of macerals, as well as their spatial distribution (Oehler and Cady 2014). By using this knowledge, the thermal maturity and hydrocarbon potential of source rocks can be estimated. In comparison to other analytical methods, CLSM offers a number of benefits, including the capacity to produce high-resolution, three-dimensional pictures of organic matter and the ability to analyse the same sample at various phases of thermal maturation thanks to its non-destructive nature.

3.12 Atomic Force Microscopy (AFM)

The morphology and nanostructure of source rocks can be studied using atomic force microscopy (AFM). In order to understand more about the porosity, pore size distribution, and mineral composition of the source rock, AFM may be used to examine the surface topography, roughness, and mechanical characteristics of the sample at the nanoscale (Li et al. 2018). Moreover, the distribution and level of thermal change in OM can be seen in high-resolution pictures of the material provided by AFM. As thermal maturity increases, the surface roughness of source rock increases, and the size and distribution of organic materials alter from nanoscale particles to a continuous network structure (Li et al. 2018). This is how AFM can be applied to assess the thermal maturity of source rock.

3.13 Laser Ablation Inductively Coupled Plasma Mass Spectrometry (LA-ICP-MS)

LA-ICP-MS is an important technique in determining the thermal maturity and hydrocarbon potential of source rocks, due to its ability to obtain high-resolution elemental and isotopic data. In this method, a tiny portion of the sample is ablated by a laser beam before being ionised and subjected to an ICP-MS analysis. The distribution and concentration of components including sulfur, nitrogen, and carbon, which are significant indicators of thermal maturity, may be determined using LA-ICP-MS. The elemental concentrations and isotopic compositions of sulfur in organic-rich shales helps in assessing the thermal maturity of source rocks since sulfur contents and $\delta^{34}S$ values decreases with increasing thermal maturity.

3.14 Pyrolysis Gas Chromatography (Py-GC)

By examining the molecular composition and structure of the organic content in the rock sample, pyrolysis gas chromatography (Py-GC) helps in determining the thermal maturity of source rocks (Peters et al. 2005a). When source rocks are heated in the absence of oxygen, organic matter is broken down into its individual molecules, which are then separated and subjected to gas chromatography analysis. The resultant chromatogram gives details on the types and concentrations of different hydrocarbons and other organic compounds found in the sample, which may be used to evaluate the thermal maturity of source rock. Since Py-GC allows for the isolation and identification of individual components based on their distinct chemical characteristics, it is especially helpful for evaluating complicated combinations of organic compounds, such as those found in source rocks (Peters et al. 2005b). This makes it a useful tool for researchers looking at the genesis and development of hydrocarbon resources, such as petroleum geologists.

3.15 Hydrogen Isotopes

The process entails measuring the deuterium to hydrogen (D/H) ratio in the organic molecules that were isolated from the rock sample. The preferential loss of hydrogen relative to deuterium causes the D/H ratio of the organic content to move towards greater levels when the rock is buried and goes through thermal maturation. The sensitivity of hydrogen isotope analysis to even modest variations in thermal maturity is one of its key benefits (Schoell 2011). The method can assist locate regions with the greatest hydrocarbon potential and can offer precise information on the sample's thermal history.

3.16 Biomarkers Identification Using Gas Chromatography-Mass Spectrometer (GC–MS)

Biomarkers can characterise the geologic periods by their abundance, restriction, and dispersion ratios in sediments and give historical information regarding the source of organic input, depositional conditions and thermal maturity (Peters et al. 2005b). The biomarker composition and ratios of particular biomarkers may determine the maturity level of the source rock. For instance, the maturity of the source rock may be inferred from the presence of certain biomarkers like hopanes and steranes in crude oil (Peters et al. 2005b). The isomerization of steranes, the existence of different alkanes, and the ratio of certain alkane isomers may all be used to evaluate the thermal maturity of source rock. The maturity and the type of organic matter input may be determined using the ratio of odd- to even-numbered n-alkanes in a specific range (Scalan and Smith 1970). Similarly, the Ts/(Ts + Tm) ratio is commonly used to determine the maturity of source rock (Peters et al. 2005b).

3.16.1 Scanning Electron Microscopy (SEM)

Scanning electron microscopy (SEM) is an imaging technique that uses a focused beam of electrons to create high-resolution images of surfaces. SEM is used to examine the mineralogy, pore structure, and micro texture of the rock in the context of source rock analysis, which might yield important details regarding its thermal maturity (Peters et al. 2005b). The conversion of clay minerals to more stable minerals like quartz, for instance, is an indication of thermal maturity and may be seen in SEM images (Bernard and Horsfield 2014). In addition to imaging, SEM can also be used in conjunction with other analytical techniques such as energy-dispersive X-ray spectroscopy (EDS) and electron backscatter diffraction (EBSD) to identify and quantify specific minerals and textures within the rock (Bernard and Horsfield 2014). These methods can offer useful details on the distribution and makeup of minerals, which are crucial for comprehending the formation and expulsion of hydrocarbons.

3.16.2 Transmission Electron Microscopy (TEM)

TEM offers high-resolution pictures of the distribution of minerals and pore spaces inside the rock matrix as well as the interior structure of organic materials, such kerogen. Transmission electron microscopy and energy dispersive X-ray spectroscopy (TEM–EDX) provide a very accurate method for accessing the nanotexture and local chemistry of clay minerals (Berthonneau et al. 2016). TEM may assist assess the level of thermal maturity as well as the type of organic matter available in the source rock by examining the microstructural changes in kerogen (Zhao et al. 2014). The link between organic matter and minerals, which may have an impact on the thermal development of source rocks, may be studied using TEM as well.

Gas shales are self-contained source-reservoir systems with huge continuous (unconventional) dimensions, as opposed to conventional systems. Shale gas systems display microscale and nanoscale mineralogical and chemical heterogeneities, which are a direct outcome of their depositional settings and diagenetic processes, rather than forming uniform and featureless deposits (Bernard and Horsfield 2014). Imaging these gas shale nanopores needs a high-quality processing and imaging approaches such as argon milling or Focused ion bean scanned electron microscope (FIB-SEM) imaging to maintain the fine features of microstructure with the fewest artefacts. The thermally changed bitumen, also known as pyrobitumen compounds, has recently been identified as the nanoporous organic particles found in thermally mature gas shale samples using synchrotron-based STXM (Bernard and Horsfield 2014).

The long process of thermal modification of organic materials in sedimentary rocks continues from the early stages of diagenesis to catagenesis and ultimately to the later phases

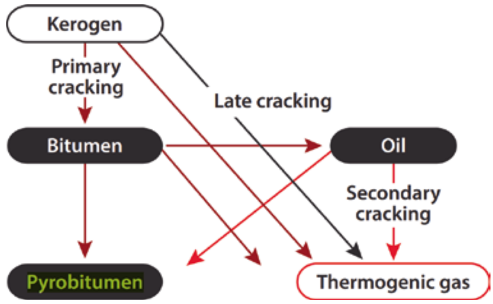

Fig. 3 Sketch illustrating the processes that occur within source rocks in gas shales, leading to the generation of thermogenic gas (modified after Bernard and Horsfield 2014)

of metagenesis. Several types of organic molecules, including pyrobitumen, are formed at each of these steps, which distinguish them from one another. Pyrobitumen is the carbon-rich residue form during the secondary cracking process from oil to gas (Fig. 3).

In secondary cracking, hydrogen is distributed unevenly, resulting in the formation of hydrogen-rich species (such as dry and wet gases) and hydrogen-poor species (such as pyrobitumen), which is accompanied by shrinkage to create secondary porosity (Bernard and Horsfield 2014). Pyrobitumens are important for thermal maturity study as it provides useful indication of the degree of thermal modification or maturation that a sedimentary rock has undergone. The use of synchrotron-based STXM has recently enabled the identification of nanoporous organic particles seen inside thermally mature gas shale samples as thermally changed bitumen, i.e., pyrobitumen compounds (Fig. 4) (Bernard and Horsfield 2014). This method will aid in understanding the complex interplay of rock fabric, gas transport, and hydrocarbon recovery in both conventional and unconventional reservoirs.

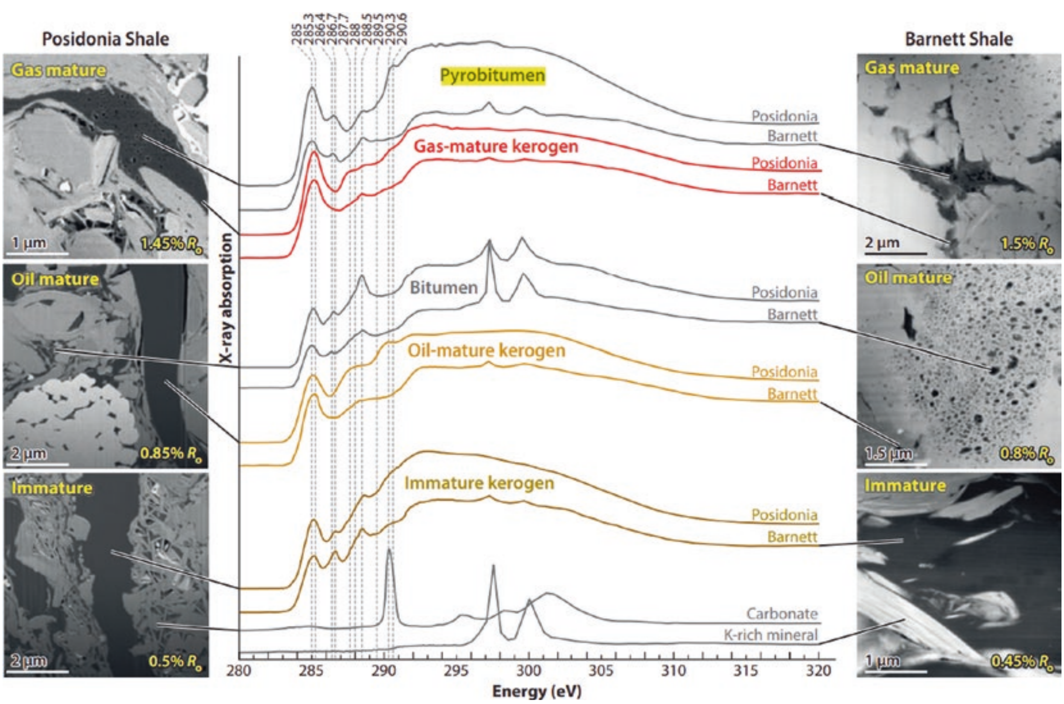

Fig. 4 Spatial variability in chemistry and structure of thermally mature organic-rich shales at the sub-micrometer scale (modified after Bernard and Horsfield 2014)

4 Conclusion

Source rock characterization includes several parameters such as typing of OM, its depositional environment and thermal maturation history. Thermal maturity is a crucial factor assessed during source rock characterization because it determines the type and quantity of hydrocarbons that can be generated from the rock. It identifies the timing and duration of petroleum generation in a basin, and provides insights into the geological history of the basin. This article discusses several physical and chemical techniques for measuring thermal maturity as well as new developments in the study of thermally altered bitumen (pyrobitumen). These recent efforts will undoubtedly contribute to increasing the accuracy of the kinetic models used to forecast the amount and type of hydrocarbons generated within such intricate self-contained source-reservoir systems, despite the fact that fundamental scientific questions regarding the transport mechanisms in unconventional gas shale reservoirs still need to be answered.

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Shale Gas Reservoir Characterization: Understanding the Shale Types and Storage Mechanisms for Effective Exploration and Production

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Abstract

Shale gas refers to the natural gas trapped within shale formations, which are fine-grained sedimentary rocks rich in petroleum and natural gas resources. It exists in shale rocks as either free gas or adsorbed gas, resulting from the thermal alteration of kerogen, an insoluble organic matter. Shale acts as both the source and reservoir rock for shale gas. When the hydrocarbon generated inside the shale cannot be expelled to the reservoir rock, the shale itself becomes the reservoir. Various factors influence the gas generation and accumulation processes, including the extent and thickness of the shale layer, total organic carbon content, kerogen type, maturity, permeability, mineralogy, and brittleness versus ductility. Although shale rocks serve as both the source and reservoir, the extraction of shale gas requires hydraulic fracturing techniques such as acidization, propane injection, CO_2 fracturing, and other methods. The exploration of shale reservoirs involves assessing total organic content, porosity, micro-fractures, and the geometry of porous spaces. Therefore, integrated studies encompassing geological, geochemical, petro-physical, geophysical, geomechanical, and technical aspects are necessary to identify optimal areas for shale gas exploration, exploitation, and recovery.

Keywords

Shale · Sedimentology · Geochemistry · Reservoirs · Adsorption · Exploration

1 Introduction

Shale is a common sedimentary rock composed of fine-grained particles, including clay minerals (such as kaolin), quartz, and calcite (Butt 2012; Ibad and Padmanabhan 2022). Its distinctive characteristic is its tendency to split into thin layers, known as fissility, with each layer being less than one centimetre thick (Zhang, 2019a). Shale can also be referred to as mudrock, encompassing clay-rich fissile mudrocks (Gu et al. 2018; Hawkins and Pinches 1992; Zhang et al. 2013). The color of shale varies based on the presence of different minerals, with red, brown, green, and black hues indicating the presence of ferric oxide, iron hydroxide, micaceous minerals, and carbonaceous material, respectively. Shale primarily consists of clay

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minerals, quartz, feldspar, carbonate minerals, and iron oxides (Hazra et al. 2016; Thickpenny 1984). Clay minerals like kaolinite, montmorillonite, and illite are the major components of shale, with the dominance of specific clay minerals varying depending on the age of the rock (Hazarika et al. 2023a, b). The transformation of clay minerals results in the formation of various minerals such as quartz, chert, calcite, dolomite, ankerite, hematite, and albite (Fan et al. 2015; Ruessink and Harville 1992). Shales contain a significant amount of organic matter, making up about 95% of the organic content in sedimentary rocks (El Nady and Hammad 2015). Black shales, formed in oxygen-deprived conditions, contain reduced free carbon, ferrous iron, and sulfur, which contribute to their dark colorationxrf (Schieber 2011). Shales are commonly found in marine environments with highly saline groundwater (Hazra et al. 2016; Kala et al. 2021a, b). The deposition of shale occurs in slow-moving water, such as lakes, lagoons, river deltas, floodplains, and offshore areas below the wave base. These sediments remain suspended in water for extended periods compared to larger particles like sand. Thick deposits of shale are often found near ancient continental margins and foreland basins. Black shales are prevalent in Cretaceous strata along the margins of the Atlantic Ocean, deposited in fault-bounded silled basins associated with the breakup of Pangea (Schieber 2011). The development of shale's fissility occurs during compaction, where clay particles become strongly oriented into parallel layers. Factors such as the clay composition and the binding of hydrocarbon molecules can influence the degree of fissility. During burial, shale undergoes diagenesis, which involves compaction, lithification, and mineralogical changes. Compaction and pressure solution lead to the reduction of pore space and the cementation of grains (Lash and Blood 2004; Xu et al. 2020; Zheng et al. 2022a, b). Lithification occurs through the deposition of cement and the alteration of clay minerals (Aird 2019). The deeper burial stages are associated with the highest degree of compaction and lithification (Moore and Wade 2013; *The Petroleum System Introduction and Definitions*, n.d.-b). When shale is exposed through erosion, additional changes occur due to meteoric water, including dissolution of cement and oxidation of pyrite (Mahoney et al. 2019).

Shale is an important source rock for hydrocarbons, including natural gas and petroleum (Hazarika et al. 2023a, b). Its fine particle size and lack of strong currents in the depositional basin contribute to the preservation of organic matter. Over time, the organic matter undergoes chemical changes, transforming into kerogen, which can further convert into graphite and petroleum under higher temperatures and pressures at greater burial depths (Rabbani and Babaei 2021; Zhang et al. 2012, 2013).

1.1 Classification of Shales

Shales are a type of sedimentary rock that forms through the transportation, deposition, and compaction of silt and clay particles. Their main distinguishing characteristic is their fissility, which refers to the property of easily splitting along thin, closely spaced parallel layers. Shales can be classified based on various observable features and the environment in which they were deposited (Okeke and Okogbue 2011a). A brief description about shale classification is given below,

Texture-based classification: Shales are typically composed of fine-grained silt and clay particles, with the dominant constituent determining their classification. If silts dominate, they are called silty shale, and if clays dominate, they are called clay shale. When shales contain significant amounts of sand, they may be referred to as sandy shale or arenaceous shale (Jiang et al. 2017; Okeke and Okogbue 2011a; Slatt 2011).

Mineralogical composition-based classification: Shales can be classified as quartzose, feldspathic, or micaceous shale, depending on the predominant presence of quartz, feldspar, or mica minerals, respectively, as determined through X-ray diffraction (XRD) analysis (Fan et al. 2015; Ruessink and Harville 1992).

Cementation-based classification: Shales, like other sedimentary rocks, are cemented by minerals or elements after deposition and compaction. The dominant cementing material can be used for classification, as it can affect the properties and performance of the shale. Common cementing materials include silica, iron oxide, and calcite or lime, leading to classifications such as siliceous, ferruginous, or calcareous (limy) shales (Athy 1930; Bjørlykke 2015).

Depositional environment-based classification: Shales are deposited in various sedimentary environments, including lacustrine (continental), deltaic (transitional or marginal), and marine environments (Kala et al. 2021a, b). Shales deposited in lacustrine environments contain a mixture of clay, silt, and sand, inorganic carbonate precipitates, and various freshwater invertebrate organisms and plant deposits (Thickpenny n.d.; Zhao et al. 2017). Deltaic shales are characterized by alternating marine transgressions and regressions, shallow depth, and a concentration of kaolinite/illite/montmorillonite clay minerals. Marine shales are typically darker in color, richer in marine planktonic fossils, and found in deeper environments with oxygen deficiency and a concentration of illite/montmorillonite clay minerals (Chutia et al. 2013; Ghosh et al. 2022; Hayashi et al. 1997).

Organic matter content-based classification: Shales can be classified as carbonaceous or bituminous based on their organic matter content. Carbonaceous shales contain dominant organic matter from plant fragments such as pollen grains, stems, and leaves, indicating a continental or transitional depositional environment. Bituminous shales contain dominant organic matter from animal fragments such as fossils, typically associated with deltaic or marine environments. Both carbonaceous and bituminous shales serve as important source rocks for petroleum oil and gas generation, depending on their kerogen content (Hu et al. 2017; Mroczkowska-Szerszeń et al. 2015; Tanykova et al. 2021; Zhang et al. 2012).

Strength-based classification: The strength of shales can be assessed using the slake-durability index, which measures the resistance of the rock to cycles of wetting and drying (Selen et al. 2020; Singh et al. 2005). Shales with a slake-durability index below 80% are classified as soil-like, while those with an index above 80% are classified as rock-like. Soil-like shales undergo Atterberg Limits tests to determine their plasticity index, while rock-like shales are subjected to point load strength tests. The strength characterization of shales can also be derived from stress/strain curves, where soft rocks exhibit ductile behavior and hard rocks exhibit brittle behavior.

Properties of shales: Shales exhibit various petrophysical and geomechanical properties that are used in engineering evaluations. Petrophysical properties include density, porosity, permeability, and clay content, while geomechanical properties include plasticity index, slake-durability index, swelling potential, hardness, point-load strength (tensile), uniaxial compressive strength (Ahmad 2014; Bai et al. 2016; Hazarika et al. 2019).

1.2 Shale as Source Rock and Reservoirs

Shales play a crucial role as source rocks in the generation of petroleum. Certain favorable conditions need to be met for a source rock to have the potential to generate petroleum. These conditions are outlined by various researchers. Total organic carbon (TOC) content: The source rock should have a TOC content greater than 0.5%. Organic matter in the rock contributes to the generation of hydrocarbons. Hydrogen index (H1): The hydrogen index, which represents the hydrogen content of the organic matter, should be greater than 150 mg Hc/g TOC. A higher hydrogen index indicates a higher potential for hydrocarbon generation Wotanie et al. 2022).

Oxygen index: The oxygen index, representing the oxygen content of the organic matter, should be less than 160 mg CO_2/g organic carbon (org.C). A lower oxygen index indicates favorable conditions for hydrocarbon generation.

Liptinite content: Liptinite is a type of organic maceral that includes certain organic compounds with a high hydrogen content. The source rock should have a liptinite content greater than 15%, indicating a higher potential for petroleum generation.

Temperature range (Oil window): The temperature range within the source rock, known as the oil window, should typically be between 100 and 250 °C. This range is conducive to the transformation of organic matter into petroleum.

Vitrinite reflectance: Vitrinite is another organic maceral that reflects light. The vitrinite reflectance (Ro) should range from 0.5 to 1.2%. This parameter indicates the maturity of the organic matter and its potential to generate petroleum.

Additionally, sufficient organic matter of the right quality, favorable chemical composition of the kerogen, and an appropriate thermal history are also important factors for petroleum generation, as outlined by Tissot. Petroleum traps can be categorized as structural or stratigraphic. Shales play a role in both types of traps. In structural traps, which involve folded or faulted formations, shale acts as a cap or seal rock, preventing the upward migration of hydrocarbons. In stratigraphic traps, which result from facies changes or the presence of coral reefs, shale can act as a seal rock. Shale smears, where shale forms a barrier to fluid migration, are also known to act as seal rocks. In petroleum-rich regions like the Niger Delta, North Sea, and Gulf of Mexico, both structural and stratigraphic traps with shale seals are commonly found, facilitating the accumulation of petroleum. Shales, traditionally considered impermeable, can become viable reservoirs for oil or gas when they undergo natural or induced fracturing. Natural fracturing in shales occurs due to volume changes associated with compaction at great depths. These fractures, often vertical and continuous, are known as joints and can enhance permeability. Systematic fractures occur in parallel sets and intersect other joints or discontinuities, while dip joints are perpendicular to bedding planes (Harding and Lowell 1979; Hill et al. 2007; Okeke and Okogbue 2011b). Naturally fractured shale gas reservoirs, such as the Devonian shales in the Appalachian Basin, Michigan Basin, and Illinois Basin in the United States, have been successfully producing gas since the mid-1980s. Although production rates are generally low (20–200 thousand cubic feet per day), these wells have long life spans. The recovery efficiency of gas in place is also relatively low (5–10%). To optimize gas extraction, horizontal wells are typically drilled into the shale to maximize contact with the gas pay zone. Through fracturing, shale reservoirs can achieve increased permeability, allowing for the accumulation and economic extraction of oil or gas. This reframe acknowledges the transformative potential of fracturing in shale reservoirs, enabling them to serve as productive reservoirs for hydrocarbons (Barati and Liang 2014; Donaldson et al. 2014; Moore and Wade 2013; Wanniarachchi et al. 2017).

2 Shale Reservoir Characterization

In recent years, shale gas resources have gained prominence as a viable energy source, thanks to successful developments in the Mississippian Barnett Shale in the Fort Worth Basin using hydraulic fracturing and horizontal drilling (Hill et al. 2007; Loucks et al. 2009). This breakthrough led geoscientists to explore other shale basins in the United States, such as the Devonian Antrim Shale in the Michigan Basin, Devonian Ohio Shale in the Appalachian Basin, Devonian New Albany Shale in the Illinois Basin, and Cretaceous Lewis Shale in the San Juan Basin (Dong et al. 2019; Dong and Harris 2020; Lash and Blood 2004). Subsequently, the Fayetteville Shale in Arkansas and the Woodford Shale in Oklahoma were also developed in 2004, followed by the Haynesville Shale in 2008 (Chopra et al. 2012). The development of these shale formations challenged the traditional approach of gas generation in source rocks followed by migration into separate reservoir rocks. Shale gas formations serve as both the source and reservoir rocks, eliminating the need for migration. Due to their near-zero permeability, shale formations act as their own seals (Hazarika et al. 2023a, b). The gas within these formations can be trapped as free gas in natural fractures and intergranular porosity, as gas sorbed into kerogen and clay particle surfaces, or as gas dissolved in kerogen and bitumen. Shale gas reservoirs have specific characteristics that determine their potential as productive shale gas plays. These include organic richness (total organic carbon content), maturation level (reflected by vitrinite reflectance), thickness, gas-in-place, permeability, mineralogy, brittleness, pore pressure, and depth (Huang et al. 2020). The optimal combination of these factors contributes to favorable productivity (Boruah et al. 2019; Boruah and Ganapathi 2015).

2.1 Geological and Geohysical Analysis

Given the varying properties of different shale gas reservoirs, it is essential to conduct thorough studies before implementing any exploitation plans. Geophysical workflows, utilizing 3D surface seismic data, are employed to characterize shale gas formations (Chopra et al. 2012). One approach involves using well log data, where resistivity measurements can indicate the presence of nonconducting hydrocarbons in mature rocks (Liu et al. 2018). The ΔlogR technique, proposed by Passey et al. (1990), utilizes scaling of transit time and resistivity curves to identify organic-rich intervals and estimate total organic carbon (TOC) content, which is linearly related to maturity (Kamali and Mirshady 2004). Other attributes from log curves, such as sonic, density, resistivity, and porosity, can be crossplotted to gain further insights and distinguish reservoir zones from non-reservoir zones (Moore et al. 2011; Ogiesoba and Hammes 2014). Løseth et al. (2011) demonstrated the possibility of establishing a relationship between TOC values and acoustic impedance through crossplotting measurements from cores and well logs (Løseth et al. 2011). This relationship can be used to transform acoustic impedance volumes into TOC volumes derived from simultaneous inversion. Shale gas logs typically exhibit high gamma ray readings, high resistivity, and low photoelectric effect due to the presence of kerogen (Fertl et al. 1980). Gamma ray logs can serve as a proxy for predicting TOC content (Lüning and Kolonic 2003). Natural Gamma Ray Spectroscopy (NGS) logs aid in lithology interpretation and can differentiate carbonaceous layers (uranium-rich) from true shales (thorium/potassium-rich), influencing lateral continuity probabilities (*7-Natural-Gammaray-Spectrometry-1984*, n.d.; Klaja and Dudek 2016). Formation Micro-Imager (FMI) logs are useful for identifying fractures, fracture networks, structures, and rock textures (Watton et al. 2014). These geophysical workflows and log interpretations provide valuable information for characterizing shale gas formations, understanding their properties, and identifying reservoir zones for successful exploitation.

Seismic studies play a crucial role in shale gas exploration, providing valuable information for various purposes. These include the delineation of shale gas beds, determining their thickness and areal extent, estimating closure stress in combination with amplitude-versus-offset (AVO) analysis, identifying optimal areas for hydraulic fracturing, and demarcating zones for fracturing. Researchers have utilized different seismic methods and attributes to study shale gas resources. For example, Gupta (2013) and Guo et al. (2010) used coherence and most-negative principal curvature to map lineaments correlated to subtle faults seen on vertical seismic data in the Anadarko Basin and Arkoma Basin, respectively (Guo et al. n.d.; Gupta et al. 2013). Hill et al. (2002) reported the high spatial variability of petrophysical and petrochemical properties in the Marcellus formation. In 1976, Jaeger and Cook studied the mechanical properties of shale, specifically brittleness and ductility, using seismic data. The seismic properties of kerogen in shale formations exhibit characteristics such as low density (~ 1.3 g/cc) and low velocity. This can result in high amplitude and low impedance reflections, similar to coal, under favorable conditions.

2.2 Geochemical Analysis

Geochemical analysis is another important aspect of shale gas exploration. The hydrocarbon generation potential of shale depends on factors such as the presence of organic matter (at least 0.5% weight), types of organic matter (which determine gas, oil, or both), and thermal maturity. Maturity can be determined using various indicators, including vitrinite reflectance, thermal alteration index, fluorescence, and Lopatin's time–temperature index. Vitrinite reflectance, which measures the reflection of light on the surface of vitrinite, is a widely used method (Hayashi et al. 1997; Kala et al. 2021a, b; Rackley 2017; Singh and Chakraborty 2021).

The permeability of shale is generally negligible, and gas production in commercial quantities requires fractures to provide permeability (Grathoff et al. 2016). Horizontal wells are often used in shale gas formations because natural fractures or joints in most shale formations are vertical (Lecampion et al. 2017). By drilling vertically to the target formation and then horizontally through the shale, more vertical fractures can be intersected. Multistage stimulation treatments, including hydraulic fracturing, are performed to create and extend fractures around the wellbore. Proppant injection is also important to keep the fractures open, and different proppants and fracturing fluids are used depending on the characteristics of the shale formation (Donaldson et al. 2014; LaFollette and Hurt 2016; Montgomery and Smith 2010; Qian et al. 2020a, 2020b).

2.3 Laboratory Characterization

The Helium Porosimeter is a valuable tool used to measure the porosity of rocks and calculate their grain density. It plays a crucial role in determining permeability through air by utilizing Ultraperm 400, which relies on steady-state gas flow measurement. This equipment combines data acquisition and real-time graphical display with mass flow, providing more accurate and precise permeability data.

X-ray powder diffraction (XRD) is a rapid analytical technique primarily used for identifying the crystalline phase of a material. It helps in determining unit cell dimensions and is particularly useful for identifying unknown crystalline materials. XRD analysis involves finely grinding and homogenizing the material, determining its average bulk composition, and then scanning it using an X-ray diffractometer after powdering it to 300 mesh using the Fritsch Micro Pulverisette-7 instrument (Josh et al. 2012; Kurtulus et al. 2012; Muktadir et al. 2021).

The scanning electron microscope (SEM) uses a focused beam of high-energy electrons to generate various signals from the surface of solid specimens. SEM is commonly used to generate high-resolution images and assists in identifying phases based on qualitative chemical analysis and crystalline structure. Operating at voltages between 10e20 kV, SEM allows for magnification of up to 20,000×. X-ray microtomography is another technique that can be used to create a 3D virtual model of a specimen without damaging the original sample. Microtomography scanners provide isotropic or near isotropic resolution, allowing for alternative representations of the volume by stacking individual slices (Chandra et al. 2023; Hazra et al. 2016; Sohail et al. 2020; Zheng et al. 2022a, 2022b).

Before evaluating a field for shale gas, it is essential to acquire total organic carbon (TOC) and vitrinite reflectance (VRO) data from the formation (El Nady and Hammad 2015; Kar et al. 2022; Pan et al. 2020). Conventional core or side wall core analysis is the preferred method for acquiring this data. Combining these properties with basin modeling studies can provide valuable insights into the hydrocarbon potential volume. Petrophysical analysis encompasses both core analysis and log analysis, which involve determining physical rock properties based on lithological characteristics, identifying sedimentary structures, and analyzing lithology, visible fractures, and partings. A typical shale gas log displays high gamma values, high resistivity, and low photoelectric effects due to the high concentration of kerogen and low water saturations.

Geomechanical studies play a vital role in identifying sweet spots in shale gas reservoirs. Unlike conventional plays that primarily focus on wellbore stability or sand production, shale gas reservoirs require extensive core and core plug studies. The Vp/Vs ratio and P-impedance can be used to differentiate shale reservoirs from non-reservoir shales, with shale gas reservoirs typically exhibiting lower Vp/Vs ratios (Alam et al. 2021; Sohail et al. 2020; Vermylen 2011).

Figure 1 shows an example from the Barren Measures Formation of the Raniganj Field, and their classification the shale based on laboratory

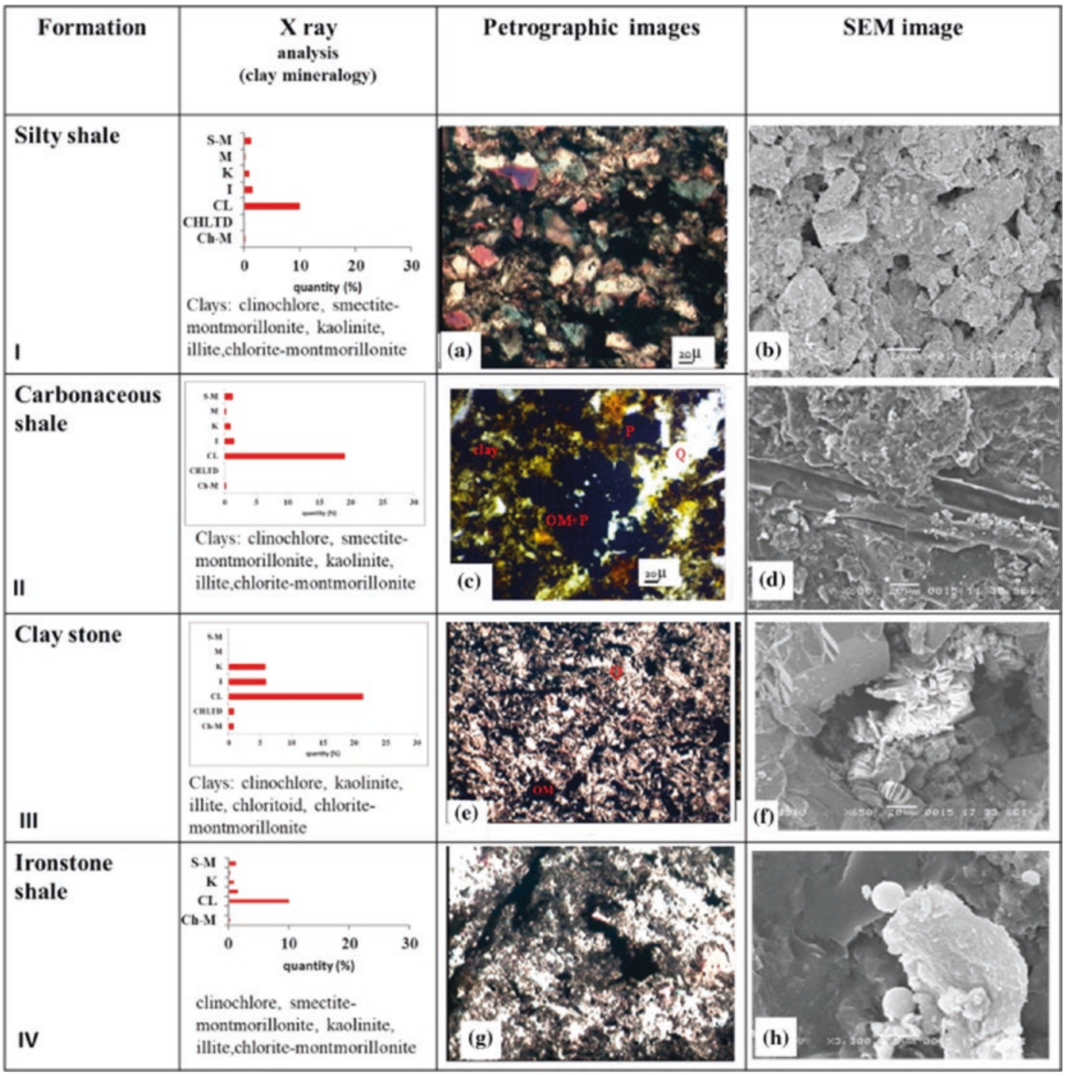

Fig. 1 Classification of lithofacies of Barren Measures shale based on mineralogy, petrography and scanning electron microscopy. I. Silty shale: photomicrographs **a** and **b** illustrate sub rounded quartz grains coated with clays. II. Carbonaceous shale: Photomicrographs **c** and **d** indicate presence of organic matters where grains are coated with iron. III. Claystone: **e** indicates presence of clays; **f** booklet type of kaolinite clays. IV. Ironstone shale: **g** iron precipitation in the microfractures; **h** iron nodules (Boruah and Ganapathi 2015)

analysis of the shale samples (Boruah et al. 2019).

Reservoir properties analysis has increasingly been carried out at the nanometer scale to understand pore geometry, organic material storage, hydrophobic pore walls, and gas-wetting in shale reservoirs. The location, distribution, and amount of organic matter within gas shales are crucial parameters for estimating gas reserves. However, the understanding of connectivity between different pore and wettability systems remains limited. Shale gas flow is controlled by diffusion, adsorption, and desorption mechanisms, with viscous flow, Knudsen diffusion, and molecular diffusion being the main types. Efforts are ongoing to develop numerical simulators that incorporate flow modelling in mixed wettability systems (Kudapa et al. n.d.; Michel et al. 2011; Tian et al. 2014; Zhang 2019a, 2019b, 2019c).

Exploring and exploiting shale gas reservoirs require a comprehensive approach that integrates various techniques. Geological, geochemical, geophysical, and reservoir characterization techniques are employed to gain a thorough understanding of the shale reservoir. Advanced laboratory techniques, including micro to nano scale imaging techniques, are crucial for studying the shale reservoir and its properties (Hazra et al. 2016; Sohail et al. 2020). These techniques help in analyzing the pore structure, organic content, and connectivity within the reservoir, providing valuable insights for efficient exploration and exploitation processes (Fig. 2) (Chopra et al. 2012).

Understanding the pore-size distribution of shale is crucial for estimating its transport and storage behaviour (Fig. 3). Shale possesses complex multiple-scale pore structures that are more intricate than those found in conventional

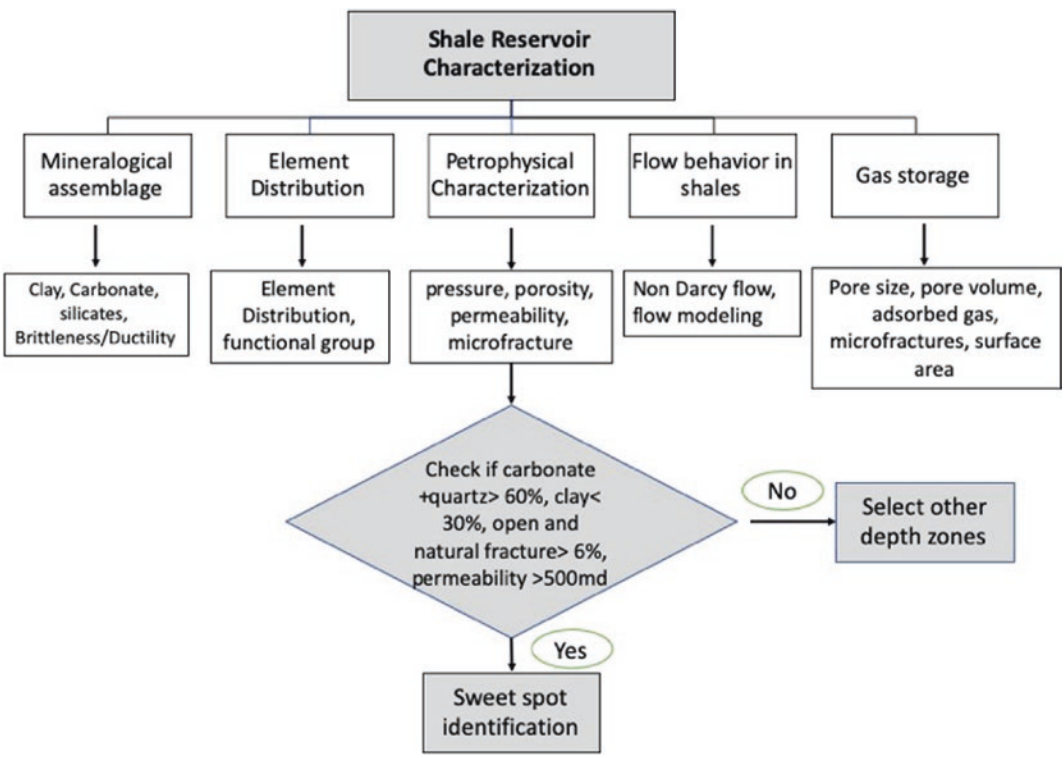

Fig. 2 Flow chart for shale reservoir characterization

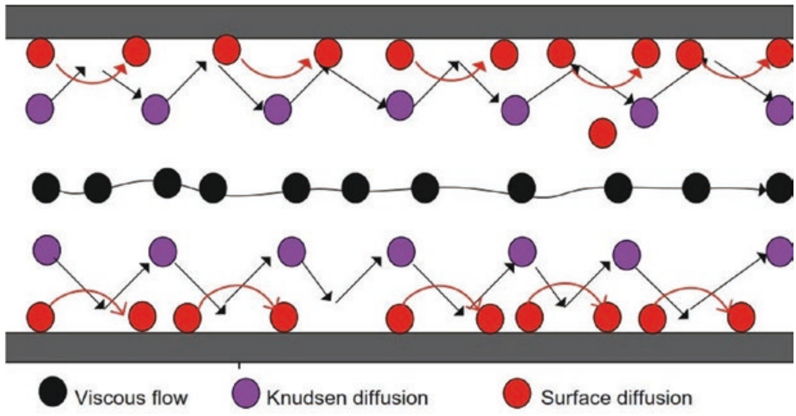

Fig. 3 Gas flow in the shale reservoir

reservoir rocks (Kuila and Prasad 2013a). Despite having low porosity, shale has the ability to hold a significant amount of natural gas in an adsorbed state on its internal surfaces (Kuila and Prasad 2013b; Loucks et al. 2009). The Brunauer–Emmett–Teller (BET) theory is commonly used to explain the physical adsorption of gas molecules on a solid surface and is applied in the measurement of the specific surface area of shales (Brunauer, Emmett, Teller 1938). This technique involves multi-layer adsorption using non-corrosive gases such as nitrogen, argon, or carbon dioxide as adsorbents to determine surface area data (Farajzadeh et al. 2009; Macht et al. 2011; Matthias Thommes et al. 2013; Wang et al., 2020). The methane sorption capacity, specific surface area, and pore size distribution of shale can be quantified using the N_2 gas adsorption technique, which allows examination of fine pores within the range of 1.7–200 nm (Bustin et al. 2008a, 2008b; Chalmers et al. 2012; Ross and Marc Bustin 2007, 2009).

2.4 Reserve Estimation

There are several numerical equations to estimate the shale gas reserves, which combines both the free and adsorb gases. Mavor et al. (1996) proposed the numerical equations for free gas and adsorbed gas calculation (Mavor et al. 1996).

3 Horizontal Drilling and Hydrofracturing

Horizontal drilling is an effective technique that minimizes land disturbance by allowing multiple wells to be drilled from a single drilling pad. This approach increases the exposure of the wellbore to the shale rock, thereby enhancing the recovery of natural gas from the shale formation (Kim et al. 2015; LaFollette and Hurt 2016; Qian et al. 2020c). Horizontal drilling, combined with hydraulic fracturing (fracking), is the current method used for efficient production from unconventional reservoirs (Zheltov and Khristianovich 1955).

Hydraulic fracturing, commonly known as "fracking," is a method of extracting natural gas and oil from underground rock formations by injecting high-pressure fluid into the rocks to create fractures. These fractures then allow the trapped hydrocarbons (such as natural gas and oil) to flow more easily to the wellbore and be extracted. Rocks with low permeability, typically less than 1 millidarcy (mD), are ideal candidates for stimulation through hydraulic fracturing. The process involves injecting a high-pressure fluid into the wellbore, exerting enough pressure to fracture or break down the rock formation (Barati and Liang 2014; Gandossi 2013a, 2013b; Lecampion et al. 2017; Möri and Lecampion 2021; Rutqvist et al. 2013;

Shimizu et al. 2011; Snapshot and Overview 2021; Stanisławek et al. 2017; Zhao et al. 2014).

The first instance of hydraulic fracturing took place in 1947 in the Hugoton field, Kansas, on a gas well operated by Pan American Petroleum Corp (LaFollette and Hurt 2016). The initial fracturing fluid used, called NALPALM, was a costly and hazardous composition consisting of a gasoline gel mixed with palm oil and cross-linked with naphthenic acid (Arwini 2016). However, in subsequent years, safer fracturing fluids were developed, with water being the primary base fluid. Proppants such as clay, sand, and ceramics are often added to the water-based fluids, and cross-linked fluids using polymers, gelling agents, stabilizers, and breakers are also employed.

Hydraulic fracturing is performed by pressurizing the wellbore to a level higher than the formation's breakdown pressure, ensuring that fractures are created in the rock formation. This process allows for increased permeability and improved flow of oil and gas to the well for extraction. The use of proppant particles in the fracturing fluid is crucial for the success of hydraulic fracturing. These particles serve to suspend in the fluid and hold open the complex network of fractures created during the fracturing process. As the mixture reaches the horizontal section of the wellbore, it is released through the perforations into the surrounding rock at high pressure, contributing to the creation of microfractures. This network of cracks allows the natural gas to flow through and reach the production well, enabling the extraction of gas reserves from the shale formation (Zhao et al. 2014).

Hydraulic fracturing plays a significant role in enhancing the permeability of the reservoir rock and improving shale gas production. However, shale formations are sensitive to water, and the use of conventional fracturing fluids in shale reservoirs can lead to issues such as formation damage, clay swelling, and instability. Mineral hydration and water imbibition can reduce the effective permeability of the rock, while the improper disposal of large volumes of flowback fluids containing chemical additives can pose environmental concerns.

Therefore, there is a current need to develop environmentally friendly fracturing fluids and utilize appropriate hydrofracturing technologies with limited fluid usage. Recent research has explored the application of waterless fracturing fluids to mitigate environmental issues, and laboratory investigations have shown the effectiveness of liquid carbon dioxide (CO_2) as a hydrofracturing fluid (Hazarika and Boruah 2021). CO_2 fracturing has been suggested as a favorable technique due to its multiple benefits, including carbon sequestration, increased production, and reduced environmental hazards (Cai et al. 2007; Wang et al. 2013; Zhao et al. 2021).

4 Conclusion

In conclusion, shale rocks exhibit compositional variations, with higher clay mineral content indicating a higher likelihood of fissility. Heterogeneity of shale reservoirs is a crucial factor in commercial shale gas production. Technological advancements in hydraulic fracturing and horizontal drilling have been key to the successful development of shale gas plays. Integrated studies involving geology, geophysics, geochemistry, petrophysics, and geomechanics can help delineate potential shale plays and identify sweet spots for shale gas exploration and exploitation.

Shale gas resources have emerged as a highly promising energy source to meet the growing future energy demand. These resources are primarily found in organically rich ($>2\%$) and mature to post-mature shales with a brittle mineral composition. These shales serve as excellent sources and reservoirs for shale gas exploration. However, due to their impermeable nature and nano-scale pores, natural micro fractures are crucial for the extraction of natural gases. Artificial fracturing techniques, such as hydraulic fracturing, can be employed to stimulate the shales and enhance gas extraction.

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Advances in Well Logging Techniques for Shale Reservoirs Exploration

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Abstract

Shale is a clay-rich, argillaceous sedimentary rock that acts as a source rock for hydrocarbon. It is also considered a potential hydrocarbon reservoir for the last few decades. Because of the fineness in grain-size and complex mineralogical character, measurement of formation reservoir properties, like porosity, saturation, and permeability in shale is complicated. Petrophysical well logging methods can play crucial role to evaluate the properties of shale reservoirs. The conventional well logging methods, like gamma ray, resistivity, density, neutron, sonic, which are used for sandstone reservoirs, provide significant information about shale properties, though the interpretation of these log data needs careful validation from other sources like core data, petrographic analysis. Every logging method has its own advantages and limitations. This chapter summarizes the applications and limitations of the standard well logging methods as well as advanced techniques like nuclear magnetic resonance in shale reservoirs. The estimation of total porosity, saturation, total organic carbon, brittleness index and velocity anisotropy are discussed in details.

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Well logging · Shale petrophysics · Shale porosity · Gamma ray · Resistivity · Density-neutron · Sonic · NMR · Kerogen

1 Introduction

Well logging is a method to carry out petrophysical evaluation of a hydrocarbon bearing rock formation. Petrophysical methods combine geology, geophysics, and reservoir engineering aspects of the reservoir rock evaluation. Analysis of petrophysical data can be considered as one of the most effective ways to accurately calculate formation properties like shale volume, porosity, permeability, saturation (Guidry et al. 1990; Luffel et al. 1992; Zhang et al. 2015; Wood and Hazra 2017). The well logging tools measure specific formation properties while traversing subsurface depth intervals. The data recorded during logging are being displayed as well logs. A well log is a concise chart that shows the value of every measured formation property with respect to depth. The information received from well log data needs to be validated with the results received from the core-plug analysis, for example, X-Ray Diffraction (XRD), Scanning Electron Microscope (SEM), petrographic analysis, laboratory-measured porosity, permeability, and saturation values.

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This chapter will discuss different logging techniques used globally to evaluate basic formation properties of shale reservoirs. A basic well logging suite involves gamma ray, resistivity, neutron, density, sonic and photoelectric factor logs to evaluate shale reservoirs. Data derived from the advanced logging techniques like, pulsed neutron minerology, image logs, and nuclear magnetic resonance (NMR) logs are also recommended for shale reservoir characterization. A complete evaluation of shale beds can only be performed by combining the data from both standard and advanced well logging techniques.

2 Well Log Techniques

2.1 Gamma Ray Logging

The natural formation radioactivity can be measured using gamma ray logging (Lehmann 2010). The radioactive elements, potassium (K), thorium (Th) and uranium (U) are responsible for the natural radioactivity in rocks. Among the sedimentary rocks, shale exhibits the strongest level of natural radioactivity due to the presence of a high volume of clay mineral (Shakirov et al. 2023). Variable amounts of potassium are present in clay minerals. Gamma ray values of different rock types are listed in the Table 1. The gamma ray response measured during data logging is the cumulative radioactivity of the respective formation.

The U, Th and K spontaneously emit gamma rays which can collide with the electrons while passing through the formation. During these collisions energy level drops due to the Compton Scattering effects. Bulk density of the formation also plays important role in the energy reduction. Gamma rays lose more energy in the denser formation. Following two types of gamma ray tools are used in the hydrocarbon industry to measure gamma ray response:

Table 1 Standard gamma ray values at different lithologies (Rider 1996)

Lithology	Gamma Ray (API)
Compact sandstone	40
Limestone	20
Organic shale	170
Shale	120
Coal	30

(a) Natural Gamma ray Tool—This tool measures the cumulative gamma ray emissions coming from all three radioactive elements (K, Th, U). This tool consists of a scintillation counter and a photo-multiplier. The scintillation counter contains a sodium iodide crystal (2 cm diameter and 5 cm length) with minor thallium impurity. A "flash" is created when gamma rays pass through this crystal and the photo-multiplier helps to store these flashes for a constant time period. The accumulated energy is the detector value at that depth, which is the gamma ray measurement at the respective depth.

(b) Spectral Gamma Ray tool—This tool is used to differentiate the gamma ray emissions from three different elements. This tool also contains a scintillation counter and a photo-multiplier. The sodium iodide crystal is bigger (5 cm width and 20 cm long). This bigger crystal can identify gamma rays in pre-defined energy bins and the distinctive energy peaks helps to separate the radioactive elements. The value of characteristic energy peak for thorium is 2.62 meV, for uranium is 1.76 meV and for potassium is 1.46 meV.

The principal use of gamma ray is to quantitatively estimate clay volume or shale volume (Asquith and Gibson 1982; Bhuyan and Passey 1994). Qualitatively gamma ray data can help to identify facies, dominant clay mineral types, to understand the depositional environment and to identify the source rock. Volume of shale can be calculated from gamma ray log using the following simple Eq. (1):

$$Vsh = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \quad (1)$$

Here, GR_{log} = log value of gamma ray, GR_{min} = gamma ray value at 0% shale zone or 100% sand zone, GR_{max} = gamma ray value at 100% shale zone.

Also, the concentrations of U, K and Th derived from spectral gamma ray can help to determine the paleo redox condition or the paleo oxic condition and the depositional environment of the shale sediments. For example, U can be highly enriched in the reducing environment (Algeo and Maynard 2004). Therefore, high concentration of U indicates anoxic condition during sediment deposition. Distribution of Th is not significantly affected by the secondary processes which make this element useful to infer provenance composition for sedimentary rocks. Concentration of Th is favourable in silicate minerals included in the insoluble residue. Therefore, silica rich rocks will have higher Th concentrations.

2.2 Resistivity

Resistivity logging is the oldest logging technique used in the hydrocarbon industry. This is a measurement of the resistance of the rock body to the passage of an electric current. Natural rocks are mostly insulators. The hydrocarbon contained within the pore spaces of rock is infinitely resistive, whereas the salty formation water is more conductive. The main use of resistivity log is to differentiate between hydrocarbon and water bearing zones (Asquith et al. 2004; Mahiout et al. 2020; Jia et al. 2023). The resistivity is simply a reciprocal of conductivity and is expressed by ohm-m unit. The resistivity of rock formation depends on the following factors:

(a) Resistivity of the fluids occupying the rock pore spaces
(b) Saturation of fluids
(c) Lithology of the formation
(d) Abundance of conductive minerals in the rock
(e) Rock anisotropy
(f) Overburden pressure
(g) Pore pressure and
(h) Formation temperature.

Resistivity of rocks depends on the Formation Resistivity factor (F). If F is high, the rock shows more resistance to the current flow and resistivity increases. F is strongly influenced by the porosity and varies from one rock to another. Presence of clay minerals also affects F values in shaly sand reservoirs or shale reservoirs. The pore spaces within shale can contain formation water or hydrocarbon. But the clay minerals present in shale can also pass currents. The stacked silicate layers of clay minerals become negatively charged in the presence of water. The surface of clay minerals can absorb saline water which contains positively charged ions (Na^+). This framework of negative and positive charges helps to flow current at the clay surface. This external surface water is chemically free, but physically bound to surface and is known as "clay bound water." The capacity of clay minerals to conduct current is expressed by a term called "Cation Exchange Capacity (CEC)." CEC depends on the surface area of minerals and the formation water salinity. Higher surface area of clay minerals induces more conductivity. If the formation water salinity is higher than the seawater salinity, then the effect of conductivity due to the CEC of clay minerals will be reduced. Due to the presence of hydrocarbon and organic matter, the resistivity in gas shale reservoirs is expected to be high. But the presence of conductive minerals like pyrite can reduce resistivity in hydrocarbon-bearing shale formations. Based on the thermal maturation or depositional environment, shale reservoirs can have high resistivity or low resistivity. The type of resistivity tools has a significant effect while interpreting the resistivity log and estimating water saturation of a shale formation. Induction tools measure horizontal resistivity (R_h), whereas laterolog tools measure a combination of vertical (R_v) and horizontal (R_h) resistivities. The R_v is expected to be higher than R_h and the true resistivity is a combination of vertical and horizontal resistivity measured by laterolog tool (Chemali et al. 1987). Considering all the factors affecting resistivity measurements, it is advised to be careful and cross-check the results with other log and core information while interpreting resistivity logs in shale beds.

2.3 Density Log

Formation bulk density is the key measurement for total porosity. During this measurement, gamma rays with 662 keV are bombarded from a radioactive source (Cs-137) and collide with the electrons present in the surrounding formation (Rider 1996). Due to this collision, gamma rays lose energy because of Compton Scattering (inelastic scattering of a photon). Once the energy of collided gamma rays falls below 100 keV, those are absorbed by the rock formation through photoelectric absorption. The amount of energy loss of gamma rays is directly related to the number of electrons per unit volume of rock (electron density, ρ_e) or the amount of matter per unit volume of the rock. A gamma ray detector, kept at a fixed distance, detects the surviving gamma rays with less energy. In modern logging tools, two or more detectors are used to detect gamma rays. Detected gamma rays are sorted into different energy windows. For example, gamma rays affected by Compton Scattering, but energy higher than 100 keV, are used to calculate formation density. Gamma rays with energy lower than 100 keV and photo-absorbed by rock are used to determine lithology. Figure 1 shows a schematic diagram of the working principle of the density logging tool. Equation (2) is used to calculate electron density of the formation:

$$\rho_e = \rho_b * (2Z/A) \quad (2)$$

Here, Z = atomic number, A = atomic weight, ρ_e = electron density, ρ_b = bulk density.
Porosity (φ) is estimated using Eq. (3):

$$\varphi = (\rho_{ma} - \rho_b)/(\rho_{ma} - \rho_{fl}) \quad (3)$$

Here, ρ_{ma} = matrix density, ρ_{fl} = formation fluid density, ρ_b = bulk density.

For the sandstone matrix, ρ_{ma} varies approximately within the range of 2.65–2.68 g/cc, and for shale, this value varies between 2.0 and 2.65 g/cc. For uncompacted shale, density can be as low as 2.0 g/cc, whereas in a deeper zone, due to compaction, the density of shale can be 2.65 g/cc. In case of organic content enriched gas bearing shale, low-density organic matter (1.1–1.4 g/cc) reduces density of the shale. Also, presence of gas reduces bulk density. On the other hand, presence of high-density minerals can increase shale density. Iron minerals like pyrite (FeS_2) or siderite ($FeCO_3$) cause increase in bulk density of shale. Table 2 lists the standard density values of different rock formations (Rider 1996).

According to Rezaee (2015), density logs can also be used to qualitatively estimate the thermal maturity of shale provided no significant variation in lithology is observed at the interval of interest. Increasing thermal maturity can reduce the density of the formation due to the following reasons:

(a) Saturation fluid changed from brine to gas
(b) Creation of pore spaces due to thermal maturation

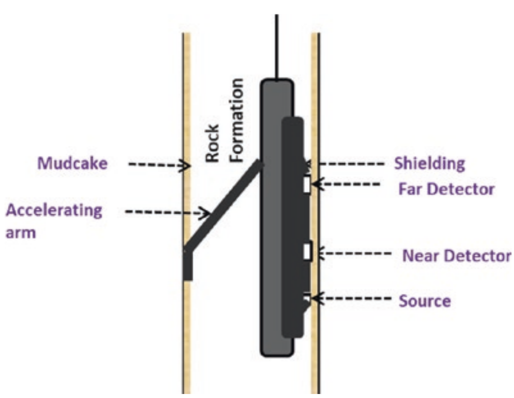

Fig. 1 Schematic diagram of density logging tool (Concept is adapted from Rider 1996)

Table 2 Standard density values at different lithologies (Rider 1996)

Lithology	Density (gm/cc)
Quartzite	2.65
Sandstone (with 10% porosity)	2.49
Limestone (with 0% porosity)	2.71
Limestone (with 10% porosity)	2.64
Dolomite (with 0% porosity)	2.87
Dolomite (with 10% porosity)	2.68
Shale	2.0–2.8 (Variable density)
Coal	1.2–1.5
Salt	2.03

(c) Increase in pore pressure due to the transformation of smectite to illite during thermal maturation (illitization)
(d) Increase in pore pressure due to hydrocarbon generation.

Use of density log to assess thermal maturity of shale can be critical and chances of erroneous interpretations increases if the shale contains both low-density organic matter and gas and high-density minerals. Therefore, care should be taken while identifying minerals of the shale formations.

2.4 Neutron Log

The density tool is generally combined with the neutron tool during well logging operations and both tools simultaneously record data (Rider 1996). Petrophysicists recommend using the combination of density and neutron porosity data for accurate estimation of formation porosity. During logging, the neutron tool bombards the rock bed with high energy neutrons that undergo elastic scattering while colliding with atoms present within the rock. The neutrons lose energy and produce gamma rays. The scattering reactions are the most effective when bombarded neutrons collide with hydrogen atoms (H), because the mass of neutrons and mass of hydrogen atoms are almost the same. The collision between two elements with almost equal masses causes losing of maximum energy. The resulting low energy neutrons or gamma rays can be detected using detectors. The count rate of those detected gamma rays is directly related to the number of hydrogen atoms present in the formation. It is obvious that the readings in neutron tool are highly sensitive to the presence of hydrogen atoms within the rock body. The hydrogen atoms are present in fluids, either in water or in hydrocarbons (gas/oil) within the rock. The formations with higher pore spaces contain a higher volume of fluids (water/hydrocarbon). Therefore, high porosity formations show an abundance of hydrogen atoms and causes frequent collision with neutrons. The bombarded neutrons will lose energy quickly and will slow down and will be absorbed within a short distance. This will result in a low count rate of slow neutrons or captured gamma rays in the receiver for highly porous rocks. The formations with lower porosity will have a lesser amount of hydrogen atoms. It will take more time for the bombarded neutrons to be absorbed. Due to slower adsorption, neutrons get more time to travel longer paths through the rock. Therefore, the neutron count rate or the number of captured gamma rays in the receiver is higher in the case of low-porosity rocks. However, in natural rocks, elements other than hydrogen present in rocks or fluids can also contribute to the neutron porosity measurements. Energy loss from neutron is much less when it collides with bigger nuclei of elements such as silicon or oxygen. The presence of a higher amount of silicate minerals will result in lower neutron porosity.

Figure 2 shows a schematic diagram of the compensated neutron tool. This tool has one transmitter and two receivers and is sensitive to thermal neutrons and can get affected by the presence of chlorine ions in formation. This tool is pressed against the borehole wall with the help of a spring-loaded arm, as shown in the figure. Readings do not get affected by borehole mud, but data can be recorded on only one side of the borehole wall.

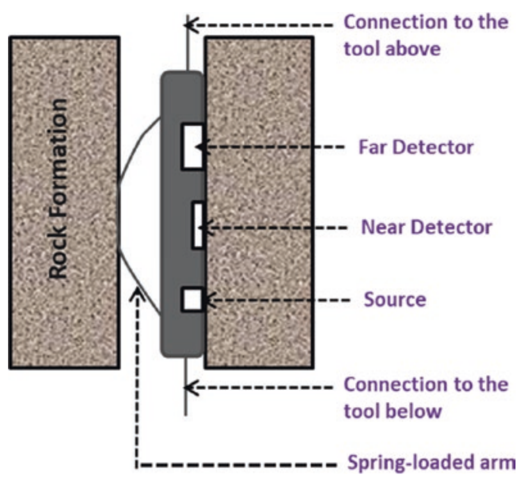

Fig. 2 Schematic diagram of compensated neutron logging tool (concept is adapted from Rider 1996)

Neutron porosity log responses need to be corrected for the hydrocarbon present in the clean matrix, as proposed by Gaymard and Poupon (1968). If the saturation of mud filtrate present is the flushed zone is $S_{xo,}$ and residual saturation is $(1 - S_{xo})$, then the porosity estimated by the neutron tool (Φ_N) is related to the actual formation porosity (Φ) as shown in Eq. (4) (Rider 1996):

$$\Phi_N = \Phi[HI_{mf} * S_{xo} + HI_{hc}(1 - S_{xo})] \tag{4}$$

Here, Φ_N = porosity measured by neutron tool, Φ = formation porosity, HI_{mf} = hydrogen index of mud filtrate, HI_{hc} = hydrogen index of hydrocarbon, S_{xo} = saturation of mud filtrate, $(1 - S_{xo})$ = residual saturation of hydrocarbon.

Table 3 shows standard values of neutron porosity expected from different lithologies.

Fluids (water or hydrocarbon) contain higher concentrations of hydrogen than non-reservoir/non-wet zones and neutron porosity shows higher value in the fluid bearing zones. The interpretation of the neutron porosity log is complicated in the gas shale reservoirs and the presence of hydrogen atoms in organic matter, clay minerals and fluids need to be considered during interpretation.

Table 3 Standard neutron porosity values of different lithologies (Rider 1996)

Lithology	Neutron log porosity (%)
Quartzite	– 2
Sandstone (with 10% porosity from density log)	6.5
Limestone (with 0% porosity from density log)	0
Limestone (with 10% porosity from density log)	10
Dolomite (with 0% porosity from density log)	1
Dolomite (with 10% porosity from density log)	18
Shale	25–75 (Variable)
Salt	– 3

2.5 Sonic Log

The travel time of sound waves is measured by the sonic or acoustic logging tool. The sonic log data is used to calculate different parameters like elastic wave velocity, rock porosity, bulk modulus (K), shear modulus (μ) of rock formation (Rider 1996). The velocity of the sound wave is compared and tied with seismic velocity. The simplest sonic logging tool consists of one transmitter to emit sound pulses and one receiver to pick up the received wave signals. The sonic log displays the record of slowness (Δt), i.e., the time required for sound wave to traverse 1ft of formation. Slowness (Δt) is the reciprocal of the velocity of the transmitted wave.

Wyllie (1963) proposed, for clean and consolidated formations with uniformly distributed porosities, transit time, and porosity (φ) are linearly related as shown in Eq. (5):

$$\varphi = \left(\Delta t_{log} - \Delta t_{ma}\right)/(\Delta t_{fl} - \Delta t_{ma}) \tag{5}$$

Here, φ = porosity, Δt_{log} = transit time measured by the tool, Δt_{ma} = transit time of the matrix, Δt_{fl} = transit time of the interstitial fluid.

Once transmitted, the sonic wave first passes through the borehole mud, then refracts from the borehole wall and encounters the formation. It passes through the formation while staying close to the borehole wall. At a critical velocity, the wave refracts back from the borehole wall into the mud and gets detected by the detector. The travel path of the sonic wave clearly indicates that the recoded data will be severely affected by drilling mud present in the borehole wall. To eliminate unwanted borehole and tool effects, modern sonic tools consist of more than one transmitter and receiver, rather than using a single transmitter–receiver combination. Figure 3 shows a schematic diagram of borehole-compensated sonic logging tool.

Table 4 lists the standard sonic compressional wave transit times for different lithologies. Compressional slowness shows wide range in shale compared to sandstone or carbonate rocks. The sonic response in shale can be significantly

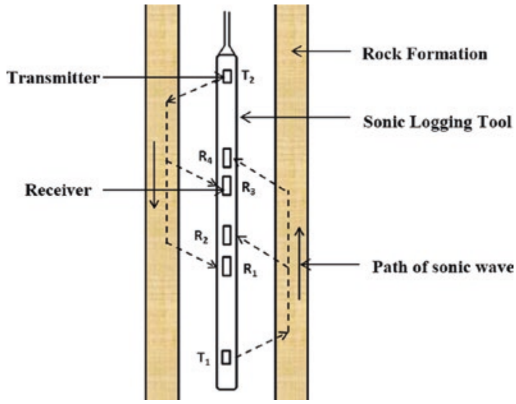

Fig. 3 Schematic diagram of Sonic logging tool (T = Transmitter, R = Receiver) (concept is adapted from Rider 1996)

Table 4 Standard sonic log responses at different lithologies (Rider 1996)

Lithology	Sonic log response (μs/ft)
Sandstone (0% porosity)	57
Limestone (0% porosity)	52
Dolomite (0% porosity)	44
Shale	60–170 (variable)
Coal	100–140 (variable)
Salt	66.7

affected by the following factors (Rezaee 2015; Zhu et al. 2011):

(a) Presence of low-density organic matter—this reduces the density, hence also reduces the velocity of sonic waves (both compressional and shear) and increases velocity anisotropy of the shale formation,
(b) Presence of gas and a high volume of clay bound water—also reduces sonic velocity and increases interval transit time.

The main applications of sonic log in shale petrophysical evaluations are:

(a) Calculation of mechanical properties of the formations, like, Young's Modulus, Poisson's Ratio, shear modulus, bulk modulus, yield strength and compressive strength. These parameters are used to determine the brittleness of the shale formation, the stability of the wellbore during drilling and regional as well as local stress directions of the field. Shale with higher brittleness is more favourable for hydraulic fracturing during hydrocarbon production.
(b) Velocity anisotropy is determined with the help of cross-dipole sonic log data. In shale, velocity anisotropy is common due to the orientations of clay minerals and presence of lenticular shaped kerogen. Velocity anisotropy is responsible for the generation of cracks and contributes to the permeability in shale.

2.6 Photo-Electric Factor (PEF)

The continuous record of photoelectric absorption cross section index (P_E) is known as the photoelectric factor (PEF) log and is acquired by the density tool. The P_E value depends on the average atomic number (Z) of the formation. Therefore, this log is strongly dependent on the lithology of the formation and is less affected by the porosity or types of fluids present in the rock. This log is principally used as a matrix indicator and can also qualitatively identify diagenetic minerals providing the borehole condition is good. PEF log is not effective in the borehole drilled with barite-mud, as the P_E of barite is almost 150 times more than that of the common rock forming minerals. This causes barite to suppress the P_E response of the lithology.

PEF value varies based on the lithology. This value in shale is 3.5, which lies between PEF values in sandstone (1.7) and limestone (5.08) (Rider 1996). According to Boyer et al. (2006), the organic rich shale can have lower PEF due to the low P_E values of organic matter or kerogen. Presence of different minerals and variability in their assemblage results the significant changes in PEF values in shale and most of the time it is difficult to produce a correct matrix detection. Table 5 lists the standard values of PEF expected at different lithologies (Rider 1996).

Table 5 Standard PEF values in different lithologies (Rider 1996)

Lithology	PEF (barns/electron)
Quartzite	1.80
Sandstone (with 10% porosity)	1.70
Limestone	5.08
Dolomite	3.14
Shale	3.5
Salt	4.65

2.7 Pulsed Neutron Mineralogy

This tool, along with C/O (carbon–oxygen) or sigma log and spectral gamma ray, is effective in determining the concentrations of the minerals present in the shale matrices in the cased holes. Concentrations of different elements like, aluminium (Al), carbon (C), iron (Fe), calcium (Ca), potassium (K), silicon (Si), magnesium (Mg), sulfur (S), gadolinium (Ga), uranium (U), thorium (Th), titanium (Ti) can be identified using this tool (Jacobson et al. 2009; Rezaee 2015). Variable assemblages of these elements' form different clay and non-clay minerals present in the clay matrix. This tool helps to identify and quantify most of the shale forming minerals, for example, illite, smectite, kaolinite, chlorite, glauconite, apatite, zeolite, halite, anhydrite, hematite, pyrite, siderite, dolomite, feldspar, quartz, and organic carbon (Franquet et al. 2012).

Standard sigma cross-section values of major sedimentary rock-forming minerals are provided in Table 6 after Jacobson et al. (2009). The shale volume calculated from the pulsed neutron mineralogy data largely depends on the presence of K-feldspar in the formation. As the sigma cross-section value of K-feldspar is very high compared to other sedimentary rock-forming minerals (Table 6), the sigma values of K-feldspar can mask the potassium yield derived from clay minerals. The potassium concentration calculated from the pulsed neutron tool needs to be cross-checked with mineral volumes calculated by other methods, like XRD (X-Ray Diffraction), XRF (X-Ray Fluroscence), SEM (Scanning Electron Microscopy), etc.

Table 6 Standard sigma cross-section values (cu) of different mineral matrices (Jacobson et al. 2009)

Lithology	Sigma cross section (cu)
Quartz	4.5
Calcite	7.1
Dolomite	4.7
Dry Clay	17.0
K-Feldspar	15.8

2.8 Nuclear Magnetic Resonance (NMR)

Nuclear magnetic resonance (NMR) is a globally used well logging method which can estimate the total porosity, volumes of micropores, movable fluid volume, volumes of clay bound water (CBW) and irreducible water, pore size distribution and permeability of the reservoir rock (Coats et al. 1999; Dunn et al. 2002; Sørland et al. 2006; Jin et al. 2023). This method can be applied to the solid core samples retrieved during drilling of the wells. NMR porosity derived from solid core plugs can be used to calibrate porosity from NMR data derived during petrophysical well logging. Also, permeability can be estimated using NMR bin porosity. Since the last two decades, the application of this method on sandstone reservoirs had been proved successful. The major application of this method lies in evaluating the low resistivity pay zones. It is difficult to distinguish between pay and non-pay zones in case of low resistivity zones, like thinly laminates sand-shale zones, clay-coated sand, sand with disseminated pyrite. NMR data is only sensitive to the fluids present in the pores of saturated rocks. Therefore, can be effectively used in shale reservoirs to estimate porosity irrespective of lithological or mineralogical variations. Extensive research studies are going on worldwide to evaluate the scopes application of NMR logging in shale (Rylander et al. 2010; Sigal and Odusina 2011; Tan et al. 2015; Ge et al. 2015).

During NMR logging, the response of hydrogen atoms gives the assessment for pores present in the rock sample. These hydrogen atoms, present in the fluids occupying rock pore spaces, can align themselves with the direction of the external static magnetic field applied on the rock during logging. This magnetic field is oscillating and is applied to tip the protons away from their new equilibrium position. Once the oscillating field is removed, those protons start relaxing back towards their original direction. The magnetic field is applied as sequences of specified pulses to generate a series of spin echoes. NMR logging tool measures these spin echoes and displays them as spin-echo trains (Coates et al. 1999). Raw NMR data consists of these spin-echo trains. The echo trains can be significantly affected by the hydrogen index (HI), longitudinal relaxation time (T_1), transverse relaxation time (T_2), and diffusivity (D). In case of saturated porous media, porosity is directly proportional to the amplitude of T_2 measurements, and the decay rate of the pulses is related to the pore sizes and the viscosity of the fluid present in these pores. Smaller pores with the larger surface to volume ratio in low permeability rocks like shale cause shorter T_2 relaxation time and vice-versa. The presence of high volume of clay minerals in shale causes high NMR relaxation rates. The clay minerals contain thin interlayers of clay bound water and the hydrogen nuclei present in the clay bound water can frequently interacts with the surface as these are close to the grain surfaces. Additionally, if the pore volumes in shale are small enough, the clay bound water can diffuse easily back and forth across the water-filled pores. Water in fine pores associated with the clay minerals with larger surface-to-volume ratios exhibits fast relaxation rates and, therefore, short T_2 porosity components. Figure 4 shows a schematic diagram of responses of typical NMR T_2 relaxation data for different types of pores within the bulk rock volume of the rock.

Total NMR relaxation includes surface relaxation, bulk relaxation of fluid precession, and diffusion relaxation caused by the gradient field. In a porous media, the total NMR relaxation can be defined as (Tan et al. 2015):

$$\frac{1}{T_2} = \rho^2\left(\frac{S}{V}\right) + \frac{1}{T_{2b}} + \frac{D(G.\gamma.TE)^2}{12} \quad (6)$$

$$\mathrm{G} = \mathrm{G}_{\mathrm{external}} + \mathrm{G}_{\mathrm{internal}} \quad (7)$$

$$\mathrm{G}_{\mathrm{internal}} \approx \mathrm{B}_0.\frac{\Delta x}{r} \quad (8)$$

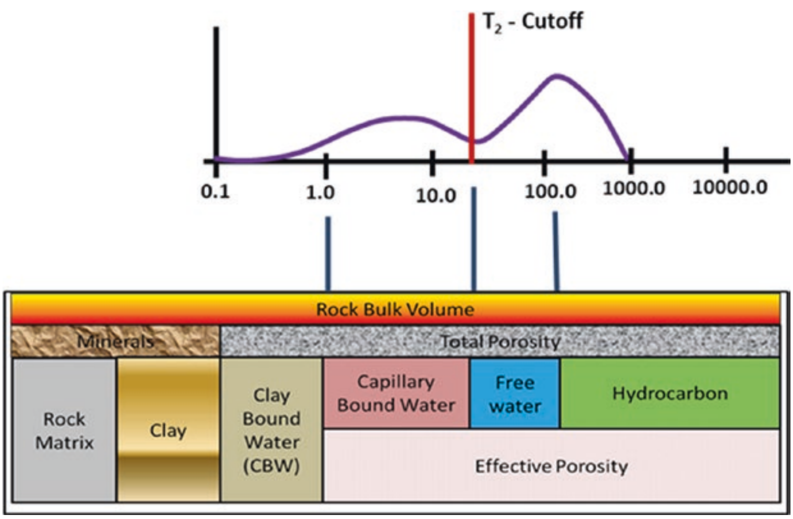

Fig. 4 Schematic diagram of NMR log data (T_2) and different types of pores and matrix within bulk rock volume (concept is adapted from Shao and Balliet 2022)

Here, ρ^2 = surface relaxivity (μs/m), S/V = surface area to volume ratio (specific surface area) of the pores (μcm−^{1}), T_{2b} = bulk relaxation, D = free diffusion coefficient for the fluid (μs/cm^2), G = magnetic field gradient that includes the external and interior magnetic field gradient (Gauss/cm), TE = echo spacing of the measurement sequence (ms), B_0 = applied magnetic field strength (Gauss/cm), $\Delta x =$ susceptibility difference between rock matrix particles and pore fluid, r = distance from the magnetic field changes (m).

While analyzing NMR raw data, selection of T_2 cutoff is the most crucial for computation accuracy (Coates et al. 1999; Ge et al. 2015), because the T_2 cutoff separates pores with different radii in T_2 spectrum. This cutoff value is an indicator of moveable fluid and reducible fluids present within pore spaces. Values above this cutoff indicate the presence of larger pores with production capability. Values below the cutoff are capillary fluids that cannot be produced. Standard T_2 cutoffs used for sandstone are 33 ms and for carbonate 90 ms. For shale, no standard value has yet been established because of its complicated mineralogy and pore structures. NMR data derived for shale needs detail analysis, and T_2 cutoff needs to be decided based on the received data for the corresponding field.

3 Petrophysical Property Analysis

3.1 Total Porosity

Estimating porosity in shale using the mentioned petrophysical logging data is not straightforward due to the presence of a high volume of organic matter in shale. Researchers (Zhu et al. 2011; Fu et al. 2015; Yu et al. 2018) have already shown that the porosity distribution in shale can be divided into two parts, matrix porosity and kerogen porosity (Fig. 5).

Presence of abundant organic matter in shale exhibits signatures similar to the highly porous rock: low density, high sonic, and high neutron porosity values. By using conventional methods of porosity calculation from well logs, it is difficult to distinguish between matrix porosity and kerogen porosity (Zhu et al. 2011; Cao et al. 2023). This results in the overestimation of porosity in the shale reservoir. To calibrate well log derived porosity with core derived porosity in shale zones, Fu et al. (2015) suggested multiplying the well log data with a factor of 0.25; but this factor cannot be used in areas of low thermal maturity.

TOC corrections can be applied to the density tool measurements while calculating porosity (Alfred and Vernik 2013; Yu et al. 2018).

Equation (3) can be modified by adding a TOC component to it as (Yildirim et al. 2019):

$$\rho_b = \rho_{ma}(1-\varphi-V_{TOC}) + \rho_{fl}\varphi + \rho_{TOC}V_{TOC} \tag{9}$$

Here, ρ_b = bulk density, ρ_{ma} = matrix density, φ = porosity, V_{TOC} = Volume of total organic carbon, ρ_{fl} = fluid density, ρ_{TOC} = density of organic carbon

Volume of TOC can be calculated from weight percentage of TOC measured using rock eval pyrolysis and other organic carbon estimation methods.

$$V_{TOC} = \frac{W_{TOC}}{\rho_{TOC}}\rho_b \tag{10}$$

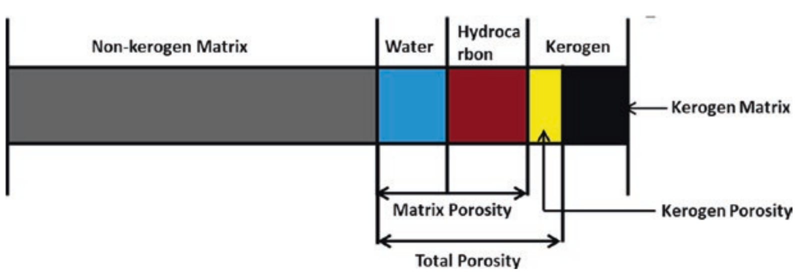

Fig. 5 Schematic diagram of fluids, kerogen and non-kerogen matrix distribution in shale (concept is adapted from Holmes et al. 2014)

Then Eq. (9) can be written as (modified from Yildirim, 2019):

$$\Phi = \frac{(\rho_{ma}-\rho_b) + \rho_b\left(W_{TOC}-\rho_{ma}\frac{W_{TOC}}{\rho_{TOC}}\right)}{\rho_{ma}-\rho_{fl}} \quad (11)$$

Matrix density plays a crucial role in calculating fluid density and porosity of the rock. In case of sandstones, a standard quartz density of 2.65 g/cc is recommended to be used. Presence of low -density kerogen and variable mineral assemblage makes the matrix density determination difficult for shale. Use of pulsed neutron mineralogy tool along with GR spectroscopy helps to accurately determine the mineral constituents and organic matter (kerogen) abundances in shale. The shale matrix density can be calculated using the following simple formula (Alfred and Vernik 2013; Rezaee 2015; Yu et al. 2018):

$$\rho_{\mathrm{ma}} = (1-\mathrm{K})\rho_{\mathrm{nk}} + \mathrm{K}\rho_{\mathrm{k}} \quad (12)$$

Here, ρ_{ma} = shale matrix density, K = kerogen volume percentage, ρ_{nk} = density of non-kerogen material, ρ_k = kerogen density

Total porosity can also be calculated using sonic log as per Eq. (5). To calculate sonic porosity in shale, a TOC component needs to be added to this equation. Adding the TOC component, the equation will become:

$$\Delta \mathrm{t} = \Delta \mathrm{t}_{\mathrm{ma}}(1-\varphi-\mathrm{V}_{\mathrm{TOC}}) + \Delta \mathrm{t}_{\mathrm{fl}}\varphi + \Delta \mathrm{t}_{\mathrm{TOC}}\mathrm{V}_{\mathrm{TOC}} \quad (13)$$

The final sonic porosity equation can be written as (modified from Yildirim et al. 2019):

$$\Phi = \frac{(\Delta t - \Delta t_{ma}) + \left(\rho_b \times \frac{W_{TOC}}{\rho_{TOC}}\right) \times (\Delta t_{ma} - \Delta t_{TOC})}{\Delta t_{fl} - \Delta t_{ma}} \quad (14)$$

Here, Δt = transit time recorded during logging, Δt_{ma} = matrix transit time, Δt_{fl} = fluid transt time, Δt_{TOC} = transit time in TOC (all transit times are in µs/ft), Φ = porosity

Total shale porosity can also be determined using NMR log. NMR data does not get affected with the lithology and mineral variations of the rock and therefore a suitable tool for shale. The best practice is to match NMR porosity with core porosity (if available) to finalize the total porosity in shale.

3.2 Water Saturation

Water saturation in clean, fluid filled sandstones can be calculated using Archie's equation (Archie 1942) (Eq. 15):

$$\mathrm{S_w} = \left(\frac{aR_w}{\varphi^m \cdot R_t}\right)^{\left(\frac{1}{n}\right)} \quad (15)$$

Here, S_w = water saturation, a = tortuosity factor, R_w = formation water resistivity, φ = formation porosity, m = cementation factor, R_t = formation resistivity. Formation water resistivity can be derived from the water salinity data measured during logging. Also, the crossplot between porosity and deep resistivity logs in a clean, shale-free, water filled porous sandstone can help to determine R_w, provided other parameters (a, m, n) are known. This plot is known as Pickett plot. Formation porosity can be calculated from different porosity logs. The a, m and n are known as Archie's parameters and can be measured from core. Formation resistivity is the deep resistivity measured during resistivity logging.

Though Eq. (15) is the simplest equation to calculate water saturation, use of Archie's equation can be difficult in shale for two major reasons:

(a) Variable salinity of formation water can make it difficult to calculate R_w accurately. A fixed value of Rw is not valid for shale, as different electrical contributions exist from clay bound water and free water. It was proposed by Glorioso and Rattia (2012), to derive water resistivity in non-kerogen intervals for gas shale reservoirs.

(b) Determine the Archie's parameters is difficult in shale. No standard method or detailed review is available on the correct measurement of these parameters in shale. The interconnected clays create more paths for electric current to flow resulting higher tortuosity in shale. This results reduction in formation resistivity factor (F) and cementation exponent (m).

Rocks with high shale volume exhibits high water saturation and low formation resistivity. In case of organic rich, gas bearing shales, water saturation is expected to be low and formation resistivity (R_t) will be high. Several models have been published so far to determine porosity and saturation in shale bearing reservoir rocks. Shale volume calculated using well log data is used to establish shaly sand relationships in the models proposed by Simandoux (1963), Bardon and Pied (1969) and Poupon and Leveaux (1971). Winsauer and McCardell (1953), Waxman and Smits (1968) proposed ionic double layer model for shaly formations. Juhasz (1981) developed a new worflow based on the Thomas-Stieber model (1975) defining various types of shale distribution in any porous sedimentary rock. As per the Thomas-Stieber model (1975), shale can be distributed in three different types as following:

(a) Laminated—shale layers are interbedded within sand,
(b) Dispersed—shales found in coating sand grains or pore filling in the sand,
(c) Structural—grain-for-grain replacement of sand grains by shale grains of approximately equal size.

Juhasz (1981) model considers total and effective porosities linked with cation exchange capacity (CEC) and formation salinities to estimate water saturation in shale bearing formations. Kazak et al. (2023) compiled a brief review on the laboratory techniques (for example, the retort method, Dean-Stark method, evaporation method and others) to evaluate water saturation in shale.

3.3 Organic Carbon (TOC)

Two different methods are used to calculate original TOC content in shale reservoirs:

(a) Pulsed neutron mineralogy tool

This tool can measure carbon content present in the shale. Carbonate minerals (calcite, dolomite, and siderite) also contain carbon. The excess carbon measured by the tool is present in the organic matter, hydrocarbon, or coal. The following Eq. (16) is used to calculate this excess carbon (Jacobson et al. 2009):

$$C_{TOC} = C_{Meas} - (C_{Cal} + C_{Dol} + C_{Sid}) \tag{16}$$

Here, C_{TOC} = carbon content in organic matter, C_{Meas} = carbon content measured by the tool, C_{Cal} = carbon content present in calcite, C_{Dol} = carbon content present in dolomite, C_{Sid} = carbon content present in siderite. Whether this excess carbon is coal or not, that is determined with the help of silicon to carbon ratio. A uranium cut-off between 4 to7 ppm is used for most gas shale reservoirs to determine whether the excess carbon is organic matter or hydrocarbon. If the uranium concentration is above this cut-off, the excess carbon is assumed to be organic matter, else it presents in the hydrocarbon.

(b) Passey method (ΔlogR method).

Passey et al. (1990) described Δlog R technique to calculate total organic carbon present in organic-rich rocks like shale, from sonic and resistivity well logs. Here R is the formation resistivity in ohm-m, measured by resistivity tool, and Δlog R is the curve separation measured in the resistivity log in logarithmic scale. This technique uses overlaying of sonic and resistivity and assumes that, in the TOC-free zones, the sonic/density log will completely overlay the resistivity log provided both logs are scaled properly. The intervals with significant TOC values will show clear separation between sonic and resistivity logs. Baselines need to be fixed on both sonic/density and resistivity logs in the zones with no TOC. Any minor change in sonic/density will deflect the values of the log from baseline. Passey et al. (1990) proposed to calculate the parameter ΔlogR using the relation (Eq. 17). It is found that Δlog R is directly proportional to the TOC content. Δlog R can be calculated from the sonic/density and resistivity overlay by using the following expression:

$$\Delta \log R = \log_{10}(R/R_{baseline}) + 0.02 \times (\Delta t - \Delta t_{baseline}) \tag{17}$$

Here, Δt = transit time measured from sonic log data (µsec/ft), $\Delta t_{baseline}$ = baseline value on transit time curve on inorganic, TOC-free shale section (µsec/ft), $R_{baseline}$ = baseline value on resistivity curve on inorganic, TOC-free shale section (ohm-m), 0.02 = constant.

Passey et al. (1990) proposed the following empirical relation (Eq. 18) to calculate TOC from $\Delta \log R$:

$$\mathrm{TOC} = (\Delta \log \mathrm{R}) \times 10^{(2.297 - 0.1688 \times \mathrm{LOM})} \quad (18)$$

Here, LOM = Level of maturity of organic matter; for example, LOM = 7 indicates the onset of oil-prone kerogen maturity, and LOM = 12 indicates the beginning of the over-maturity of oil-prone kerogen. As the sonic and resistivity logs, both are highly sensitive to the porosity change in the formation, once a baseline is set at a given lithology, any slight change in porosity will be reflected in the change or shift of the logs from baseline values.

TOC can also be measured using laboratory experimental methods like rock–eval pyrolysis (Lafargue et al. 1998). Using this method, different parameters which helps to estimate thermal maturity, hydrocarbon generation potential and kerogen typing can be estimated (Behar et al. 2001). Discussion on pyrolysis method is not under the scope of this chapter.

3.4 Kerogen Density

Kerogen density can be calculated using the combination of NMR log, density log and pulsed neutron minerology log (Vernik and Milovac 2011). Kerogen volume can be calculated using the following relation (Eq. 19) (Alfred and Vernik 2013; Yu et al. 2018):

$$\mathrm{K} = \frac{\rho_{nk} - \rho_m}{\rho_{nk} - \rho_k} \quad (19)$$

Here, ρ_{nk} = density of non-kerogen material determined using pulsed neutron mineralogy log, ρ_k = kerogen density assumed to be within 1.1–1.4 g/cc, ρ_m = matrix density derived using bulk density and NMR logs.

TOC volume (V_{TOC}) can be calculated from the computed kerogen volume by using following formula:

$$\mathrm{V_{TOC}} = \mathrm{KC_k} \quad (20)$$

Range of C_k value varies within 0.7 to 0.85 based on the maturity level and kerogen types of the shale (Rezaee 2015). Weight fraction of TOC (W_{TOC}) is calculated from TOC volume (Eq. 21):

$$\mathrm{W_{TOC}} = \frac{\rho_k}{\rho_m} \times V_{TOC} \quad (21)$$

This TOC weight fraction needs to be compared with core derived TOC or TOC from pulsed neutron mineralogy data. The assumed value of kerogen density in the Eq. (19) can be compared with the real value. According to Rezaee (2015), if the real value of kerogen density is lower than the assumed value, then calculated values of K, V_{TOC} and W_{TOC} (from NMR) will be less than the values calculated from pulsed mineralogy data and vice versa. If the assumed and real values of kerogen density are same, then similar results will be produced.

3.5 Brittleness Index (BI)

Shale with higher brittleness is more favourable for fracturing. BI is the parameter calculated to quantify the brittleness of any shale bed. The BI can be calculated by combining Young's modulus (E) and Poisson's ratio (ν) in the following equations (Dewan 1983; Rezaee 2015):

$$(\mathrm{BI})_{\mathrm{sonic}} = \frac{E_{brittle} + \nu_{brittle}}{2} \times 100 \quad (22)$$

Here $E_{brittle}$ and $\nu_{brittle}$ are defined as:

$$\mathrm{E_{brittle}} = \frac{E - E_{\min}}{E - E_{\max}} \quad (23)$$

$$\nu_{\mathrm{brittle}} = \frac{E - E_{\min}}{E - E_{\max}} \quad (24)$$

Young's modulus (E) and Poisson's ratio (ν) can be calculated using compressional and shear sonic data as per Eqs. (25) and (26):

$$\mathrm{E} = \frac{\rho V_S^2\left(3V_p^2 - 4V_S^2\right)}{V_p^2 - V_S^2} \tag{25}$$

$$\nu = \frac{\left(V_p^2 - 2V_S^2\right)}{2\left(V_p^2 - V_S^2\right)} \tag{26}$$

Young's modulus will be higher, and Poisson's ratio will be lower in brittle shale reservoirs. Both compressional and shear wave velocities are required to calculate BI using equation (Eq. 22). In case of unavailability of shear sonic data, the shear wave velocity can be estimated using the following empirical relation between compressional and shear velocities for shale formation (Castagna et al. 1985):

$$\mathrm{V_s} = 0.862 \times \mathrm{V_p} - 1.172 \tag{27}$$

Here, V_p = Compressional wave velocity, V_s = shear wave velocity

BI can also be quantified using the mineral content data derived from X-Ray Diffraction (XRD) or pulsed neutron mineralogy logs. Jarvie et al. (2007) proposed the following Eq. (28) combining volumes of quartz, clay and carbonates to calculate shale BI:

$$(\mathrm{BI})_{\mathrm{minerology}} = \frac{Vol.ofQuartz}{Vol.of\,(Quartz + Carbonate + Clay)} \tag{28}$$

Equation (28) clearly implies that the increase in the proportionate volume of quartz will increase BI. Therefore silica-rich shale will be more brittle than the clay-rich shale. Dong et al. (2023) showed that the compressibility analysis based on P-wave, S-wave and well log data (shale volume and porosity) can guide the fracturing design of shale gas exploration blocks in China.

3.6 Velocity Anisotropy

Anisotropy in formation velocity is important to evaluate the hydraulic fracturing potential of any shale reservoir. The velocity anisotropy of a shale formation depends on the difference between the shear wave velocities in the X and Y directions (Blakeman 1982; Cheng et al. 2022). The anisotropy index can be calculated using the following Eqs. (29, 30) (Vernik and Liu 1997; Rezaee 2015):

$$(\text{Anisotropy Index})_{\mathrm{X}} = \frac{\left|V_{sx} - V_{sy}\right|}{V_{sx}} \tag{29}$$

$$(\text{Anisotropy Index})_{\mathrm{Y}} = \frac{\left|V_{sx} - V_{sy}\right|}{V_{sy}} \tag{30}$$

Here, V_{sx} = shear wave velocity in X direction, V_{sy} = shear wave velocity in Y direction. Final velocity anisotropy of the formation is a simple arithmetic average of the anisotropy indices in X and Y directions.

4 Conclusion

Considering the complicated mineralogy, abundance of fine pores and low permeability, it is recommended to follow a petrophysical model or workflow, which is different from the petrophysical models for sandstone reservoirs, to evaluate shale formations. The model starts with the acquisition of correct data/well logs which will be used to identify lithology and fluid types and quantify parameters like shale volume, porosity, saturation, permeability, brittleness, TOC, and mineral content. The basic standard logs are gamma ray, neutron, density, sonic and resistivity. Other required logs are PEF, pulsed neutron and NMR logs.

Once the necessary logs are acquired, the next step is to analyze the data. Data analysis for shale beds can be broadly divided in three groups:

(a) Petrophysical analysis—lithology, shale volume, porosity, water saturation, permeability
(b) Geochemical analysis—TOC content, thermal maturity, kerogen types, inorganic mineral content
(c) Geomechanical analysis—Young's Modulus, Bulk Modulus, Poisson's Ratio, Shear Modulus, Brittleness Index.

Lithology can be assessed by gamma ray. PEF values also confirm the lithology variations identified in the subsurface formations. This confirms if the formation contains any shale or not. A combination of density and neutron logs are used to calculate shale porosity. Different types of resistivity logs (induction, laterolog, spherically focussed log) are used to measure shallow, medium, and deep resistivities, which are used to calculate saturations in flushed zone and invaded zones. NMR logs help to separate and quantify the volumes of clay- bound, capillary-bound and free fluid. NMR porosity can also be used to validate total porosity calculated from density-neutron logs. Evaluation of shale beds requires estimation of organic content. TOC can be modeled using sonic/density and resistivity logs following Passey model. Parameters like thermal maturity and kerogen typing, which helps to characterize source rock potential of shale samples, are derived from the analysis of pyrolysis experiments. Inorganic mineral concentrations are measured through pulse neutron mineralogy tools and from laboratory experiments like XRD, XRF or SEM. Analysis of sonic data provides the geomechanical parameters, which help to determine the stability of the well during drilling, feasibility of the formation to fracturing and local and regional stress direction of the field.

Once the detailed analyses are carried out on all the acquired data, it can be concluded if the shale formation possess qualities of prolific source rock, can act as a good reservoir rock, if feasible for fracturing and finally, an exploration or development plan for unconventional reservoirs can be planned accordingly.

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Recent Advances in Well Logging Techniques for Exploration of Shale Reservoirs

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Abstract

Well logs play a vital role in the exploration and exploitation of the hydrocarbon. In case of unconventional shale reservoir, exploitation of hydrocarbon is much more challenging than conventional reservoirs. Application of advanced technologies has played an effective role in the successful exploitation of shale reservoirs in North America and China. With the advancements in well logging technologies, some innovative logging tools are now available to provide more data and information to geoscientists, drilling engineer and reservoir engineer for comprehensive assessment of shale reservoirs. In this book chapter three such advanced well logs like, Litho Scanner, Sonic Scanner and Nuclear Magnetic Resonance have been included. For each of the logging tools, a brief description of principle of measurement and various applications of the log with field examples has been discussed. Well log like Litho Scanner can be used for the continuous mineralogical analysis and measurement of TOC. Sonic Scanner with cutting-edge types of acoustic measurements provides useful information about the drilling environment, the reservoir mechanical properties and hydro-fracture operation at completion stage. Such information supports in making decision that reduce overall drilling costs, improve recovery, and maximize hydrocarbon production. Nuclear Magnetic Resonance log, another advanced log, is very useful for providing information for reservoir characterization and analysing producibility. Application of these advanced logs will be very advantageous for better understanding and evaluation of the resources for hydrocarbon exploration and exploitation in a time efficient and cost-effective manner.

Keywords

Unconventional Shale Resource · Advanced well log · Litho Scanner · Sonic Scanner · Nuclear magnetic resonance

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1 Introduction

Well logs play a very important role in the petroleum industry. Well-logging techniques are widely used at various stages right from the exploration to the production phase in the oil and gas sectors. Well log can be defined as a recording of any parameter related to the characteristics of the subsurface rock formations encountered by measuring downhole equipment in the drilled borehole, continuously against the depth (Serra 1984). So, well log provides a data set which gives the variations of some parameter with depth across the recorded interval in the well. With the growth of the well logging technology, several logging tools have been developed and used to measure many parameters to address various properties of the subsurface formation like electrical, acoustic, physical including porosity, density, radioactive and chemical including mineralogy (Serra 1984; Goldberg 1997; De et al. 2019a). A combination of different well log suits help to get better information and picture of the subsurface formation. Otherwise, for getting detailed information about the subsurface formations, geologists need continuous conventional coring of the formation which is not feasible technically and economically. As an alternative option, drill cuttings can be used. But drill cutting is not so reliable because of contamination and inconsistency in term of depth accuracy and thus provide a very inaccurate record of the formation (Sanei et al. 2020). At this stage, well logs can be considered an acceptable substitution for continuous coring with reasonable accuracy in a time-efficient and cost-effective manner to get required geological information (De et al. 2019b). Additionally, another advantage of well logging is that it provides the measurements of rock properties under in situ condition unlike measurements carried out on core samples in the laboratory (Goldberg 1997). Furthermore, all other measurements in the well are referenced with respect to the logging depth as well logging measurements are having depth accuracy.

Keeping space with technological development, many advanced logging tools have been inducted in the well logging services, in addition to the basic logs, to provide more data and information to geoscientists, drilling engineers and reservoir engineer. Unlike conventional hydrocarbon reservoir, in the case of unconventional shale reservoir, exploration and exploitation are very much challenging because shale hydrocarbon reservoir is characterized by complex lithology with very poor porosity and ultra-low permeability (Boyer et al. 2011). The application of advanced technologies plays a vital role in the successful exploitation of shale reservoirs in North America and China (Lin 2016). In the area of well logging, some advancements in well logging technologies helped to have a better understanding and evaluation of shale reservoirs. Estimation of parameters related to source quality (SQ), reservoir quality (RQ), and completion quality (CQ) are crucial in the evaluation of a shale reservoir for commercial success.

Recently developed advanced well logs like, Litho Scanner, Sonic Scanner, and Nuclear Magnetic Resonance (NMR) are now being used to estimate parameters related to SQ, RQ, and CQ for better evaluation of the shale reservoir. Well log like Litho Scanner can be used for the continuous mineralogical analysis of the formation (Schlumberger 2017; Yan et al. 2018). It can also be used to determine source quality parameters of the shale formation through estimation of parameters like Total Organic Carbon Content (Schlumberger 2017; Yan et al. 2018; De et al. 2019b). NMR log along with Litho Scanner log can provide a better evaluation of reservoir quality through estimation of various petrophysical parameters like porosity, permeability, clay content, water saturation, etc. (Kadkhodaie and Rezaee 2016; De et al. 2020). In the assessment of completion quality, well logs like Sonic Scanner, Litho Scanner, are also very useful for the estimation of parameters related to geomechanical properties of the formation including the brittleness index for evaluation of fracability (De and Sengupta 2021b). In this book chapter, a description of some of the advanced well logging tools and their applications will be discussed briefly.

2 Litho Scanner

The mineral composition of a rock formation is having significant controlling effects on the reservoir quality and completion quality of the hydrocarbon resource. Knowledge of mineral composition will help for better characterization of the reservoir. Complications during the drilling process can be addressed and reduced with the detailed information about the mineralogical composition of the formations to be encountered. At the completion stage for extracting production from shale reservoir, the effectiveness of hydro-fracture required for stimulation job to enhance production is also controlled by mineral composition. The mineral composition can be accurately estimated by laboratory measurements on core samples. However, for a thick shale reservoir with few core samples limited representation of the mineralogical composition of the formation will be obtained. To address the important requirement of mineralogical composition, well logging service provider has come out with an advanced geochemical logging tool. M/s Schlumberger has introduced Litho Scanner logging tool with the innovative technology of new-generation gamma ray spectroscopy (Schlumberger 2017). Litho Scanner log can provide a continuous estimation of elemental concentrations and mineralogical composition of the formation in a time-efficient manner with reasonable accuracy.

2.1 Principle of Litho Scanner Spectroscopy

High energy (in MeV) neutrons are emitted by the pulse neutron generator (PNG) in the Litho Scanner tool. These emitted neutrons interact with elements in the surrounding formation and induce the emission of gamma rays. The emissions of gamma rays from the formation are induced via two primary interactions: inelastic scattering and thermal neutron capture (Schlumberger 2017). High energy (energy greater than 1 meV) neutrons at the initial stage suffer loss of energy with inelastic scattering with nuclides of the elements in the formation. Excited nuclides emit gamma rays. The energies of these gamma rays have discrete set of values that are characteristic of the elements involved in emitting gamma rays. After suffering some scatterings, the high-energy neutrons come down to thermal neutrons stage (energy less than 0.4 eV) and then thermal neutrons are being captured by some elements. Again, the capture of thermalized neutrons by atomic nuclei results in the emission of gamma rays. Now the energies of these gamma rays have also specific discrete values which are characteristic of the element responsible for the capture (Schlumberger 2017).

In the Litho Scanner tool, both types of gamma ray spectra are recorded using a suitable detector and recording system. In the Litho Scanner tool, LaBr3:Ce spectroscopy detector with high resolution and high count rate capabilities is used (as shown in Fig. 1) The detector is coupled to a high-temperature spectroscopy photomultiplier, producing signals that are integrated, digitized, and processed by a pulse-height analyzer with high-performance capability (Yan et al. 2018). The analyzer determines the pulse height, which is proportional to energy, of each detected gamma ray in the spectra and accumulates pulse-height histograms that tally counts versus pulse height. Neutrons are emitted in pulses and there is a suitable time gap between two neutron bursts to avoid the contamination of inelastic spectra with capture spectra. Spectra are acquired during and after each neutron burst, which enables the separation of the inelastic and capture of gamma rays. Then each spectrum is disintegrated into a linear combination of standard spectra from individual elements. The coefficients in the linear combination of the standard spectra are transformed to elemental weight fractions using a modified geochemical oxides closure model or an inversion approach. Thus, after data processing, the tool can provide elemental concentrations in the formation. Elemental concentrations are then used to generate mineralogy and lithology fractions.

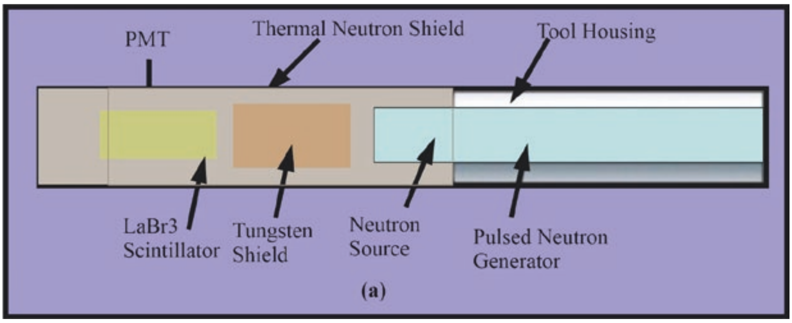

Fig. 1 A representative sketch of a Litho Scanner tool (Schlumberger 2017; Yan et al. 2018)

Two methods are generally used for deriving mineralogy and lithologic fractions from the elemental concentration logs. One is sequential processing based on the derivation of empirical relationships between elemental concentrations and mineral concentrations (Schlumberger 2017). The other is by using an iterative inversion technique with a multicomponent inversion solver (Schlumberger 2017). A sketch of the Litho Scanner tool has been shown in Fig. 1.

2.2 Elements Measured in Inelastic and Capture Spectroscopy Using Litho Scanner

In Litho Scanner tool, some elements are detected and measured with only inelastic spectra, some elements are estimated using only capture spectra and some elements are detected and measured using both inelastic and capture spectra. Detail of the elements measured in the Litho Scanner tool using inelastic and capture spectroscopy is shown in the Table 1 (Yan et al. 2018).

2.3 Evaluation of Total Organic Carbon Content

Total organic carbon content (TOC) is the most important source quality parameter for evaluation of an organic-rich shale reservoir. TOC can be accurately measured by laboratory measurement on core samples. However, there is a limitation in this method because of scarcity of core samples to represent the whole shale formation under study and time-consuming

Table 1 Suite of elements measured in inelastic and capture spectroscopy using Litho Scanner

Name of the element	Element symbol	Capture spectra	Inelastic spectra
Aluminium	Al	Yes	Yes
Barium	Ba	Yes	Yes
Bromine	Br	Yes	Yes
Carbon	C		Yes
Calcium	Ca	Yes	Yes
Chorine	Cl	Yes	Yes
Copper	Cu	Yes	
Iron	Fe	Yes	Yes
Gadolinium	Gd	Yes	
Hydrogen	H	Yes	
Potassium	K	Yes	Yes
Magnesium	Mg	Yes	Yes
Manganese	Mn	Yes	
Nitrogen	N	Yes	
Sodium	Na	Yes	Yes
Oxygen	O		Yes
Phosphorus	P	Yes	Yes
Sulphur	S	Yes	Yes
Silicon	Si	Yes	Yes
Strontium	Sr	Yes	
Titanium	Ti	Yes	

preparation and laboratory measurements (De et al. 2019b). Moreover, to identify potential target regions within thick shale formations, continuous estimation of TOC against depth is essential. Earlier continuous TOC was estimated indirectly in various basins using single log like Spectral Gamma Ray or some combination of basic logs like (Resistivity-Neutron), (Resistivity-density) and (Resistivity-Sonic) based on the correlation of TOC with the single log or combination of logs (Schmoker 1981; Schmoker and Hester 1983; Passey et al. 1990; Renchun et al. 2015). In recent time, another approach namely machine learning methods such as Artificial Neural Networks (ANN), Support Vector Regression (SVR) has been used for continuous estimation TOC using basic logs and core data (Huang and Williamson 1996; Amiri Bakhtiar et al. 2011; Ouadfeul and Aliouane 2015; Tan et al. 2015; De et al. 2019b; Ganguli et al. 2022). All these methods of estimation of TOC are indirect and are not convenient to use readily and the predicted results also vary depending on the use of the method.

In this scenario, Litho Scanner logging tool has come out with the innovative solution of providing the direct stand-alone measurement of TOC (Yan et al. 2018; Shen et al. 2023). Litho Scanner is capable of both measuring elemental carbon concentration and quantification of carbonate minerals in the formation. From the quantification of carbonates, inorganic carbon associated with carbonates is determined. TOC is then determined from the difference between total carbon content and inorganic carbon content. To establish the accuracy of the measurement of TOC by Litho Scanner log, a comparison of TOC values derived from the log with TOC values measured from cores was carried out M/s Schlumberger. It has been demonstrated that Litho Scanner log is capable of providing TOC measurement with reasonable accuracy, as the TOC logs observed to agree well with TOC values measured from cores for wells from different basins across North America (Schlumberger 2017). Litho Scanner log was recorded in few wells against Cambay Shale in Cambay Basin. To check the accuracy of estimation of TOC by Litho Scanner log, TOC values estimated by Litho Scanner has been correlated with the values of core-TOC and observed a good correlation as shown in Fig. 2 (De and Sengupta 2021a).

2.4 Continuous Mineralogical Composition

Important application of Litho Scanner log is that it can provide elemental concentrations and mineralogical composition of the entire shale formation in continuous manner against depth (De and Sengupta 2021b). This information is helpful for reservoir characterization. Litho Scanner can provide an accurate estimation of quartz, carbonate, and clay contents which can be used for the systematic classification of lithology in the complex shale hydrocarbon reservoir. Mineralogical composition and lithological classification are useful for reservoir characterization. A small section of the Litho Scanner log recorded in a well of Cambay Basin, India, has been shown in Fig. 3.

2.5 Estimation of Brittleness Index

Brittleness index (BI) is considered as the key completion quality parameter for shale hydrocarbon reservoirs as the success of

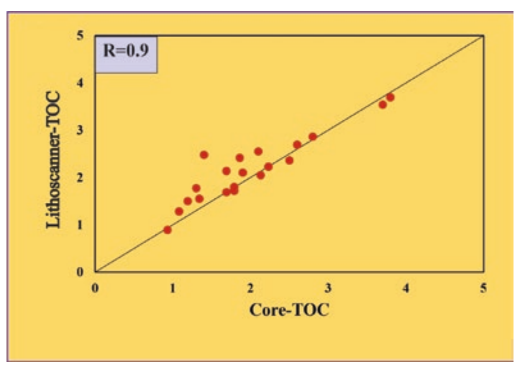

Fig. 2 Correlation between TOC from Litho Scanner log and Core-TOC for a well in Cambay Basin, India (after De and Sengupta 2021a, reuse of figure permitted by Springer Nature with license number: 5352910330259, dated July 20, 2022)

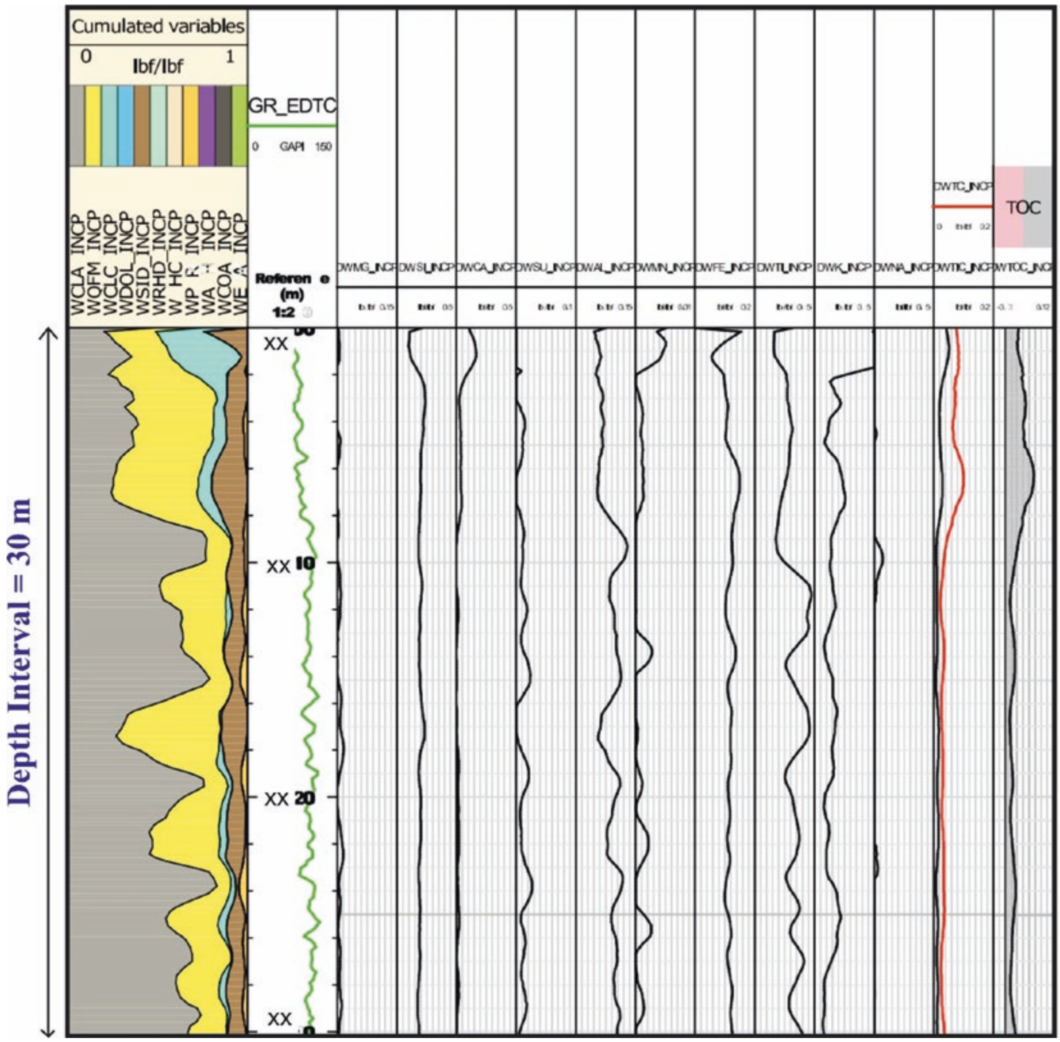

Fig. 3 A small section of Litho Scanner log recorded in a well in Cambay Basin against Cambay Shale (after De and Sengupta 2021b, reuse of figure permitted by Taylor & Francis with license number: 5441380134118, dated December 03, 2022)

hydrofracturing, which is an indispensable option to enhance production, is critically dependent on shale's brittleness. Mineral composition of the shale formation plays an important role in controlling brittleness (Jarvie et al. 2007). Based on this concept, one method of estimation of BI known as mineral-based BI (MBI) has been developed and generally used in the petroleum industry. Mineral-based BI, as proposed by Jin et al. (2015), considering siliceous minerals (quartz, feldspar and mica) and carbonate minerals (calcite and dolomite) as brittle minerals, can be expressed as:

$$\begin{aligned} &\mathit{Mineral\ Brittleness\ Index}\ (\mathit{MBI}) \\ &= \frac{W_{QFM} + W_{Carbonate}}{W_{Total}} \end{aligned} \tag{1}$$

where, W_{QFM} is the sum of the weight fractions of quartz, feldspar and mica; $W_{Carbonate}$ is the weight fraction of total carbonate minerals, and W_{Total} is the sum of weight fractions of all minerals in the formation.

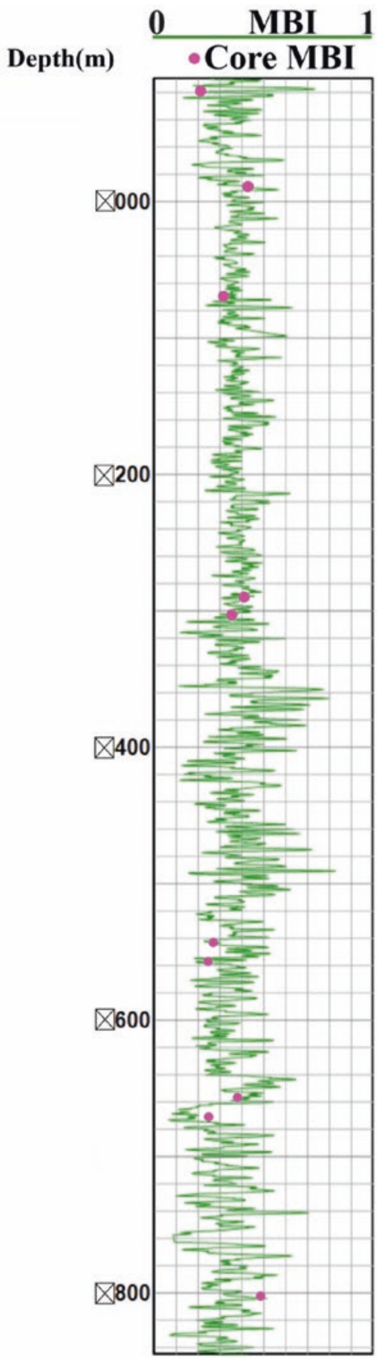

Fig. 4 Plot of MBI derived from Litho Scanner log along with MBI (marked as pink dot) using mineralogy from core measurement (after De and Sengupta 2021b, reuse of figure permitted by Taylor & Francis with license number: 5441380134118, dated December 03, 2022)

All these parameters in the right-hand side of the Eq. 1, can be obtained accurately from the Litho Scanner log and hence MBI can be estimated continuously. Estimation of continuous MBI has been done in a well in Cambay Basin, using the Litho Scanner log. A plot of MBI derived from Litho Scanner log with depth has been shown in Fig. 4 along with MBI estimated using mineralogy derived from laboratory measurements on core samples. There is a good agreement, validating the suitability of using Litho Scanner for estimating BI.

2.6 Clay Estimation

Total clay content and types of clay minerals are important in the evaluation of a shale reservoir as the presence of clay minerals significantly influences the reservoir quality (Gamero-Diaz et al. 2013; Kumar et al. 2018; De et al. 2020). An increase in clay volume fraction (V_{CLAY}) in the formation reduce the effective porosity and permeability and thus degrade the quality of the reservoir and increase the difficulty of production of hydrocarbon from the reservoir (Grieser and Bray 2007; Jadoon et al. 2018). For shale reservoirs, an increase in clay content also reduces the brittleness of the formation and thus results in difficulty in effective hydro- facture operation essential for stimulation of production. Hence clay content is also important for completion quality. V_{CLAY} can be estimated from measurements on core samples and by using well logs. For continuous estimation of V_{CLAY} indirectly, basic well logs like Gamma Ray log or a combination of Neutron-Density logs are generally used (Moradi et al. 2016). But such indirect approach to the estimation of V_{CLAY} is not very accurate. In this context, Litho Scanner log can be used to have a continuous accurate estimation of V_{CLAY} (De and Sengupta 2021a). From the Litho Scanner, the weight fraction of total clay minerals can be obtained. V_{CLAY} can be estimated from the weight fraction of clay by using the following relation:

$$V_{CLAY} = \frac{W_{CLAY}}{\rho_{CLAY}} \cdot \rho_b \tag{2}$$

where, W_{CLAY} is the weight fraction of clay obtained from Litho Scanner log, ρ_{CLAY} is the density of clay, ρ_b is the bulk density of the formation obtained from Density log. Estimation of V_{CLAY} is important for corrections of various basic well logs like resistivity, neutron, density, and sonic as all these logs are affected by the presence of clay. V_{CLAY} is used to obtain effective porosity and realistic estimation of water saturation (S_w) which are key inputs for hydrocarbon reserve estimation. Apart from clay content, the type of clay minerals present is also important to know as in terms of plasticity and swelling potential, different clay minerals are observed to behave differently (De et al. 2020). The Litho Scanner log also the provides the information on the type of different clay minerals present. Types of clay minerals present can be used to design the drilling and hydro-fracture operations.

3 Sonic Scanner Log

In recent time there is a significant advancement in acoustic measurements in petroleum industry for better geomechanical and reservoir characterization and to address various issues and complications during drilling to the production stage in the life cycle of a well (Nauroy 2011; Labani and Rezaee 2015). The focus has been on well integrity and to developing an effective methodology for enhancing the production of hydrocarbon efficiently. In this direction, a new generation sonic tool, namely Sonic Scanner, has been inducted by Schlumberger using latest acoustic technology to probe the formation. In addition to axial and azimuthal, the tool is capable of making a radial measurement and also provides 3D characterization of the formation (Schlumberger 2015). The Sonic Scanner, a new acoustic scanning platform, has been designed to provide cutting-edge types of acoustic measurements, including borehole compensated multi-spaced monopoles with long and short spacings, cross-dipole, and cement bond quality. Useful information about the drilling environment and the reservoir can be obtained with data processing of the various acoustic measurements provided by the tool. Such information supports making decisions that reduce overall drilling costs, improve recovery, and maximize hydrocarbon production. The main outputs of the Sonic Scanner tool include: compressional slowness, shear slowness, stonely slowness and full waveforms (Arroyo Franco et al. 2006). Outputs of the tool are used to determine various elastic moduli and to analyze the geo-mechanical properties of the formation.

A sketch of the Sonic Scanner tool has been shown in Fig. 5 to have an idea about the configuration of the tool.

The tool is having 13 axial stations in a 6-ft receiver array. At each station, there are eight receivers, azimuthally distributed and placed every 45° around the tool to provide a total of 104 sensors on the tool. Three monopole transmitters (upper monopole, lower monopole and far monopole as shown in the Fig. 6) are used for the acquisition of long-spaced and short-spaced data for borehole compensation with varying depths of investigation (Schlumberger 2015). Each of the three Sonic Scanner monopole transmitters generates clear P- and S-waves, the low-frequency Stoneley mode and the high-frequency energy needed for cement evaluation. Two orthogonal dipoles (X and Y as shown in Fig. 6) are used to generate flexural waves for the characterization of shear-wave slowness in slow and anisotropic formations.

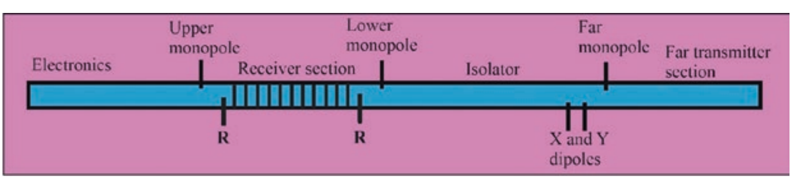

Fig. 5 Sketch of a sonic scanner tool (Franco et al. 2006; Saxena et al. 2018)

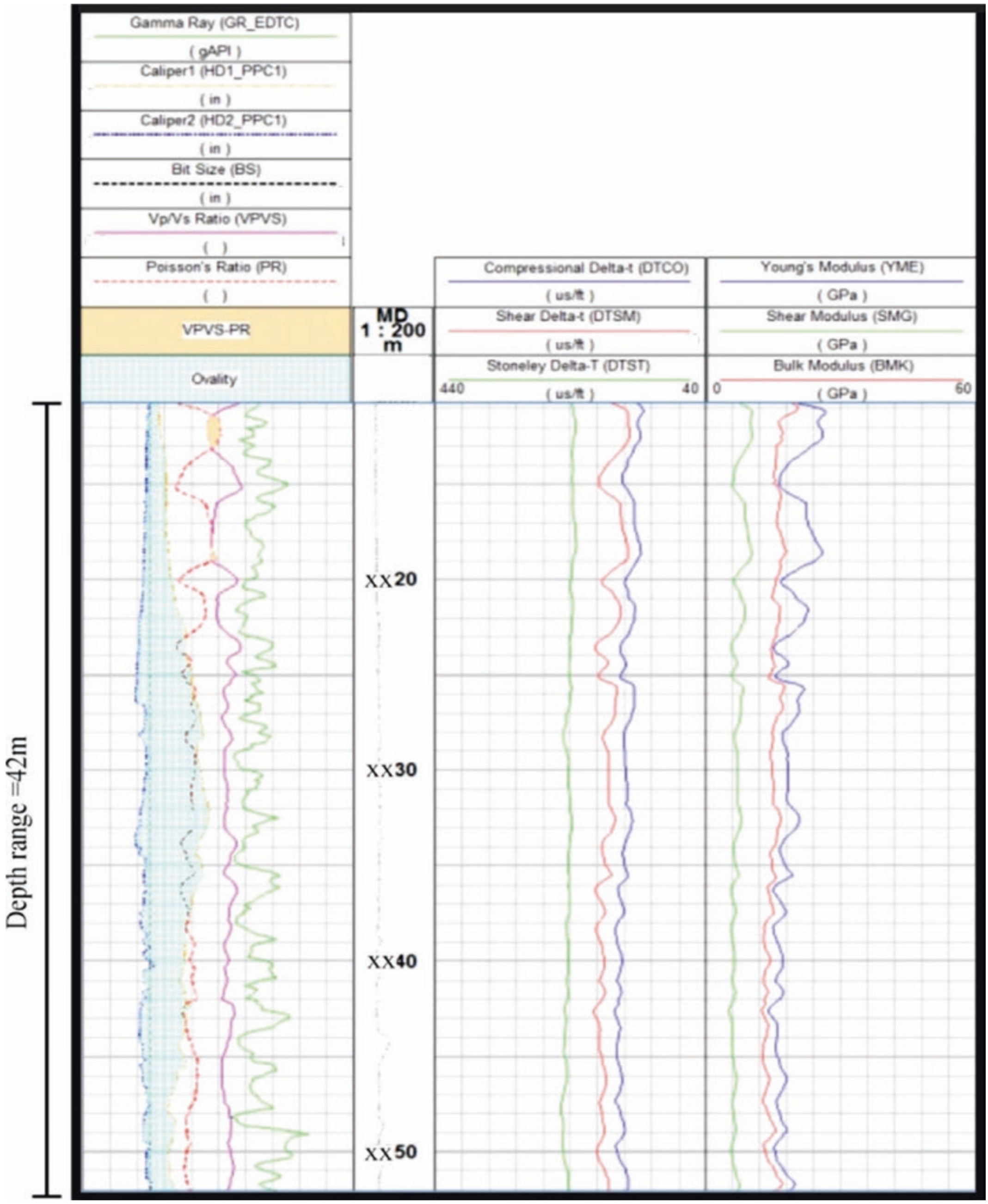

Fig. 6 Composite plot of extracted slowness, PR, VPVS and parameters related to mechanical properties for a well in Cambay Basin

One dipole vibrates in line with the tool reference axis, and the other at 90° to the axis to generates strong flexural waves.

Sonic Scanner measurements provide a very useful dataset that can be utilized for analysis of geomechanical properties and estimation completion quality parameters for evaluation of a hydrocarbon reservoir, particularly an unconventional reservoir, where drilling and production operations are more challenging (Al-Ameri and

Hamd-Allah 2023). Here, some of the applications of this log will be discussed in brief.

3.1 Analysis of Mechanical Properties

Applications of rock mechanics are critical for geologists, reservoir engineers and production engineers. In the analysis of mechanical properties, the strength of rock, in-situ stress and rock failure mechanisms are important. All these concepts are useful to understand or predict the occurrence of mechanical failure in the formation. Measurements from the Sonic Scanner log are used to obtain quantitative estimation on dynamic elastic moduli and other parameters related to mechanical properties. These parameters are critical in determining the strength of the rock and estimating the magnitude of the earth's stresses within the formation. Parameters related to mechanical properties of formation can be estimated using the following given relations (Archer and Rasouli 2012; Saxena et al. 2018) where inputs are different acoustic velocities like compressional acoustic velocity (V_P), shear acoustic velocity (V_S) obtained from Sonic Scanner log and bulk density (ρ_b) from density log.

$$Dynamic\ Young's\ Modulus\ (E_{dy}) = \frac{\rho v_s^2 (3v_p^2 - 4v_s^2)}{v_p^2 - v_s^2} \tag{3}$$

$$Dynamic\ Poisson's\ Ratio\ (v_{dy}) = \frac{v_p^2 - 2v_s^2}{2(v_p^2 - v_s^2)} \tag{4}$$

$$Dynamic\ Shear\ Modulus\ (G_{dy}) = \rho_b * v_s^2 \tag{5}$$

$$Dynamic\ Bulk\ Modulus\ (k_{dy}) = \rho_b * \left(\frac{3v_p^2 - 4v_s^2}{3}\right) \tag{6}$$

Sonic Scanner log was recorded in some wells for evaluation of Cambay Shale, Cambay Basin, India. In Fig. 6, displays a composite plot of various slowness (compressional, shear and Stonely) with extracted dynamic elastic moduli, Poisson's ratio (v), and VPVS ratio using Sonic Scanner log recorded in one such well of Cambay Basin.

3.2 Estimation of Brittleness Index

In the petroleum industry, there is one convenient method of estimation of the brittleness index using elastic moduli. There is no direct relationship between the brittleness of a rock and elastic moduli like Young's modulus (E) and Poisson's ratio (v). The theoretical concept behind the computation of brittleness with elastic parameters is that the stress–strain behaviour of a material is characterizing brittleness as well as the elastic moduli. There exhibits a distinguished correlation of brittleness with Young's modulus and Poisson's ratio which can be used for the computation of BI.

The Young's modulus (E) and Poisson's ratio (v) computed using sonic log (Eqs. 3 and 4) are called dynamic parameters (Edy, vdy) as with the propagation of sonic waves, very short duration stresses and strains are developed within the formation unlike static measurements carried out at laboratory where loading is done for a long duration with high magnitude of applied stress. It has been observed that there is a significant difference between static and dynamic modulus particularly in case of Young's modulus. However, there exists a reasonably good correlation between the two. In the absence of good number of core samples for laboratory measurements, the empirical relation (Eq. 7) for conversion of dynamic E_{dy} to static E_s, proposed for shale formation by Wang (2000) may be used as given below:

$$Static Young's Modulus (E_s) = 0.4145E_{dy} - 1.0593 \tag{7}$$

In the case of Poisson's ratio, as there is not much difference in static and dynamic measurements, the static Poisson's ratio (v_s) may be considered equal to its dynamic value (Archer and Rasouli 2012; Das and Chatterjee 2018; De and Sengupta 2021a, b). After conversion of dynamic moduli into static moduli, Sonic Scanner derived Young's modulus and Poisson's ratio, can be used for the estimation of BI, using empirical relations (Eqs. 8, 9, and 10) as given below (Grieser and Bray 2007; Das and Chatterjee 2018; De and Sengupta 2021a, b)

$$Young'sModulusBrittleness(BIe) = \frac{Es - Es_{\min}}{Es_{\max} - Es_{\min}} \quad (8)$$

$$Poisson'sRatioBrittleness(BIv) = \frac{v_s - v_{s_{\max}}}{v_{s_{\min}} - v_{s_{\max}}} \quad (9)$$

$$Brittleness\ Index\ from\ sonic\ scanner \log\ \mathrm{SBI} = \frac{BIe + BIv}{2} \quad (10)$$

Elastic moduli-based BI has been computed using Sonic Scanner log recorded in wells at Cambay Basin. In Fig. 7, SBI computed has been plotted against depth for a well of Cambay Basin.

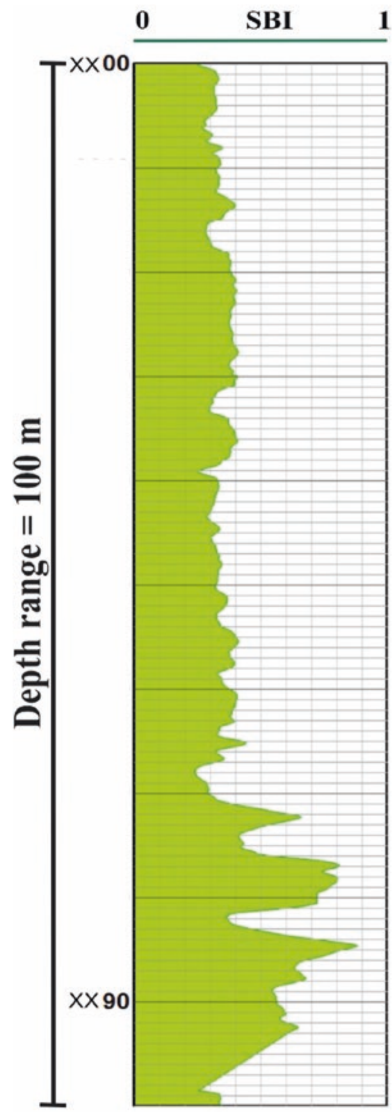

Fig. 7 Plot of SBI derived from sonic-scanner log for a well in Cambay Basin

3.3 Shear Anisotropy Analysis

A Sonic Scanner log can be used for the analysis of acoustic-based anisotropy of the formation. Flexural waves generated from the two orthogonal dipoles in the tool, provide the opportunity to identify and quantify shear anisotropy (Franco et al. 2006). The flexural waves, generated from the dipole, polarize into a fast and slow shear in the presence of elastic anisotropy in the planes containing the borehole axis. Anisotropy may be the consequence of mechanical anisotropy, fractures, or stress. Data processing of crossed-dipole sonic logs with slowness-dispersion analysis provides the ability to identify stress-induced azimuthal anisotropy. If it is confirmed that anisotropy is the result of a differential stress, then the direction of maximum horizontal stress can be determined from the direction of the fast shear wave when the well is nearly vertical (Franco et al. 2006). This technique is generally used in the petroleum industry in conjunction with other methods, like wellbore failures identified from calliper and formation image logs, to deduce the direction of the present-day maximum horizontal stress. For identification of anisotropic zones in the formation, depth wise plot of dispersion for fast and slow shear waveforms alongwith anisotropy measured in terms of SLOANI (slowness-based anisotropy), TIMANI (time-based anisotropy) and the energy difference between fast and slow shear directions can be used (Franco et al. 2006).

3.4 Fracture Analysis

Analysis of Stoneley waves from Sonic Scanner measurements can be used to identify open fractures. The low-frequency Stoneley wave is sensitive to the certain change in the formation permeability (Franco et al. 2006; Haldorsen et al. 2006). When the Stoneley waves encounter high permeable open fractures in the formation, the fluid vibrates relative to the solid, causing viscous dissipation of energy in these zones, resulting in attenuation in amplitudes and slowing down of the waves. The reductions in wave energy level and velocity vary with the frequency of the wave. Using a wide bandwidth of frequencies, Stoneley-wave dispersion data can also be processed to estimate formation permeability. After encountering the open fractures, there may be possible reflection back of the Stoneley waves toward the transmitter. The ratio of reflected to incident energy is having a correlation with openness or fracture aperture (Franco et al. 2006). The use of this technique to detect permeable fractures works well in the hard formation.

Open fracture analysis was performed in a well of Cambay Basin, using Stoneley slowness, waveform and calliper log. As shown in Fig. 8, the red curves represent the reflection coefficients from modeled waveforms while the blue curves represent the reflection coefficients from acquired Stoneley waveforms. Any significant difference in the modelled and acquired waveforms and reflection coefficients suggest the presence of possible open fracture. However, healed and very fine fracture may not be visible or detected. In the presented Stoneley fracture analysis in Fig. 8, there is an interval showing a difference in reflection coefficients from the model and acquired waveforms, where the acquired reflection coefficients (blue curve) read higher than the modeled (red curve). This indicates the presence of possible open fracture at that particular depth interval.

4 Nuclear Magnetic Resonance Logging

Technology based on the nuclear magnetic resonance (NMR) principle has been widely used in physics, chemistry, biomedicine and, more recently, in clinical diagnosis through imaging of the internal structure of the human body. Using the same physical principles of NMR, well logging service providers have come out with the development of downhole logging tools for effective in-situ reservoir evaluation. NMR tool is capable of providing various information useful for reservoir characterization (Sun et al. 2023). It is the only logging tool to give porosity measurement independent of lithology (Kenyon et al. 1995). Unlike Neutron and Density tools for porosity measurement, the NMR tool does not use hazardous radioactive source. Also, the NMR log is capable of distinguishing between bound fluid and movable fluid in the reservoir. With the remarkable advancement in the NMR tool, a reliable NMR measurements and data processing can provide unparalleled useful information of hydrocarbon reservoirs and to access the producibility of the reservoir. Recently, the NMR logging tools are being extensively used in petroleum industries for critical analysis of the complex reservoirs and a better understanding of the producibility of the reservoirs. Different logging service providers are having NMR tool with different trade names. A sketch of the NMR logging tool of Schlumberger is shown in Fig. 9 (Schlumberger 2006).

4.1 Principle of NMR Logging

The atomic nuclides possess magnetic moment due to the spinning motion of the charged nuclides and they behave like spinning bar magnets (Kenyon et al. 1995; Herrick et al. 1979).

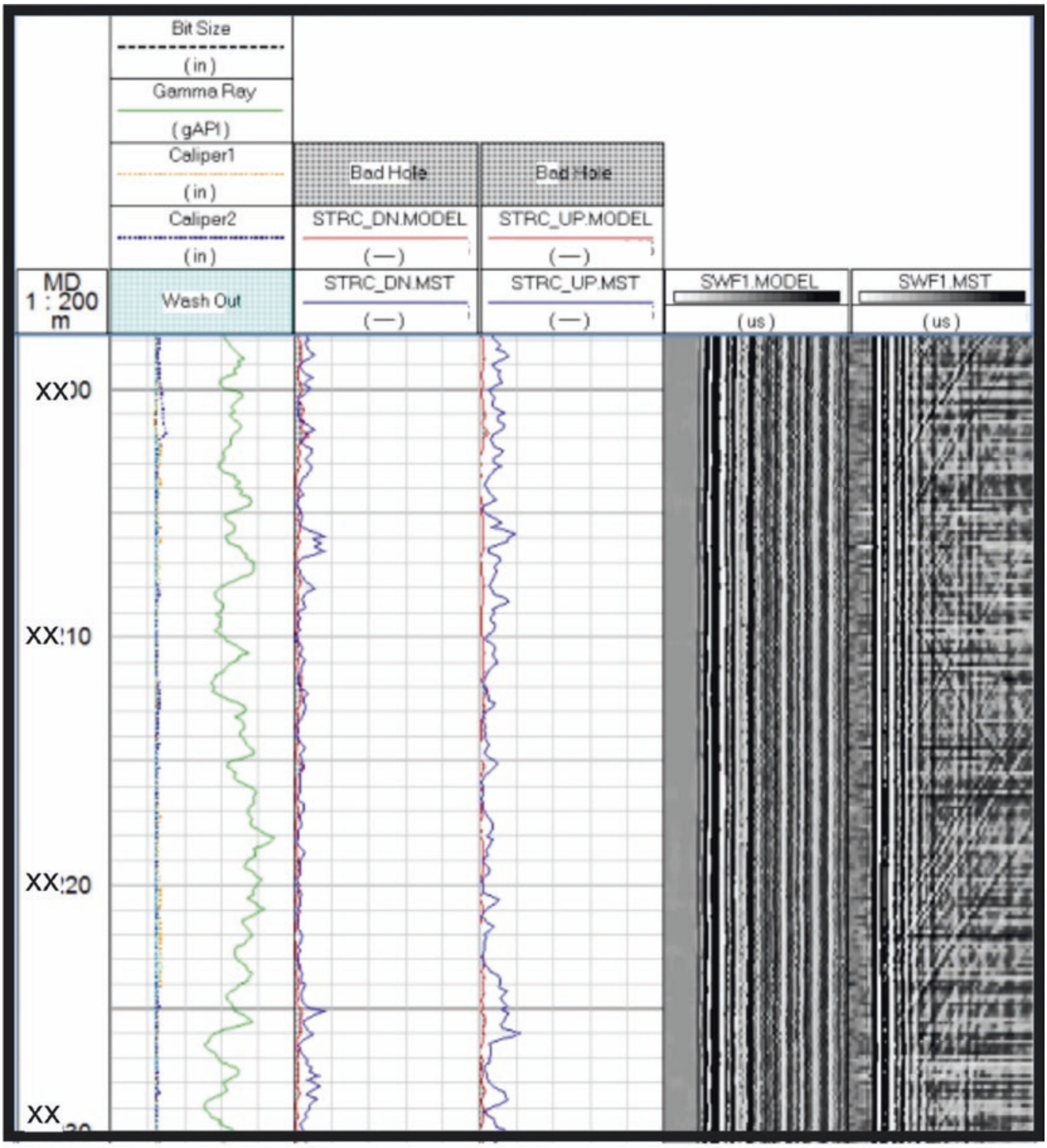

Fig. 8 Stoneley fracture analysis results for an interval in a well in Cambay Basin

Nuclear magnetic resonance is related to the principle in physics of the response of nuclei under the action of external magnetic fields. These spinning nuclei with magnetic moments can interact with externally applied magnetic fields and can produce measurable signals. But the detected signals are very small for most elements. Yet, nuclei of hydrogen have a relatively large magnetic moment and are capable of generating significant signals. Also, hydrogen is abundant in both water and hydrocarbon in the pore space of rock. By tuning NMR tools to the magnetic resonant frequency of hydrogen, the signal generated from hydrogen nuclei is maximized and can be measured with accuracy.

The nuclear magnetic resonance tool has been designed to measure the signals emitted from the spinning hydrogen nuclides when they

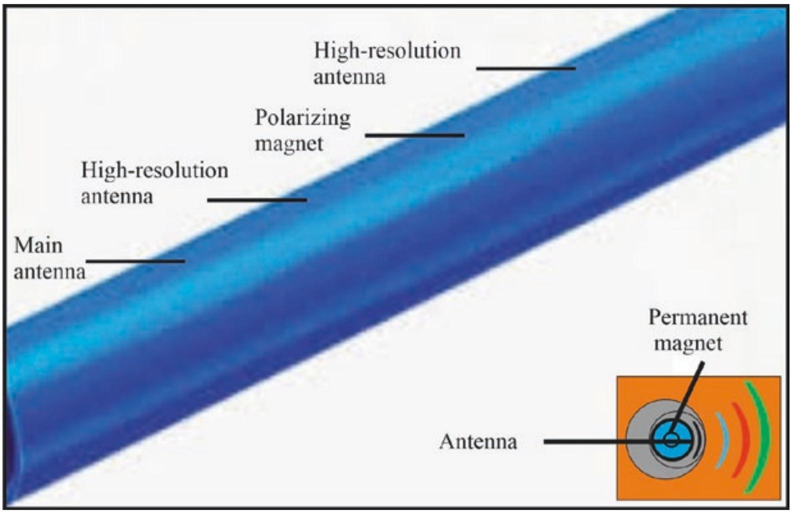

Fig. 9 A representative sketch of NMR logging tool

are stimulated by (i) the application of a strong magnetic field and (ii) the application of radio frequency pulses in the direction perpendicular to the applied magnetic field (Kenyon et al. 1995). The tool is tuned for the hydrogen nuclei so that signals from hydrogen nuclei are only significant and signals from other nuclei are negligible. Energised hydrogen nuclei return to their original state with the process of precession emitting signals. The tool measured the signals (amplitudes and decay) in the direction of the applied static magnetic field and in the perpendicular direction to the static field. Time constants associated with the decay of the signals in the both directions are measured. T1 is the time constant in the direction of the static field known as longitudinal relaxation time. T2 is the time constant associated with signals in the transverse direction of the static magnetic field and is known as transverse relaxation time.

The primary objectives in NMR logging are measuring:

(i) T_1 signal amplitude (as a function of polarization)
(ii) T_2 signal amplitude and decay, and their distributions. The total signal amplitude is proportional to the total hydrogen content and is calibrated to give formation porosity independent of lithology effects. Both relaxation times T1 and T2 can be interpreted for pore-size distribution information and pore-fluid properties (Kenyon et al. 1995).

Value of T2 will be higher for hydrogen nuclei present in the higher pore size and micro- pore, the value of T2 will be small. So, distributions of values of T2 are representative of pore size distributions. From T2 distributions, the total porosity can be determined. With suitable cut-off values of T2, the clay-bound, capillary bound and free fluid porosity can be determined. Permeability also can be determined from the T2 distributions using a suitable model with cut-off values of T2.

4.2 Advantages and Applications of NMR Log

- Unlike conventional porosity tools like neutron, density and sonic, the NMR tool provides porosity estimation which is independent of matrix minerals. So, it is the only tool to provide lithology independent porosity.
- NMR log provide not only total porosity but also porosity distribution with information

concerning pore sizes as it can distinguish between macro-pores and micro-pores.

- NMR log data can be used to differentiate clay-bound water, capillary-bound water, and movable water. It provides information on the irreducible water saturation and movable free fluid volume fraction which are indicators for reservoir producibility.
- Total response in the NMR log is very sensitive to fluid properties. NMR measurements can also be useful for fluid identification as different fluids like water, gas, light oil and viscous oil are having different polarization characteristics.
- One of the important and very useful applications of the NMR log is the ability to estimation of formation permeability.
- NMR log data helps in the identification of thin permeable beds in the laminated reservoirs.

4.3 Porosity Determination Using NMR

Porosity is one of the most important reservoir parameters and its accurate estimation is very crucial (Fernando and Ley 1992; Liu et al. 2018). Though we have several porosity tools like neutron, density and sonic, but measurements by these tools are lithology dependent. Measurements of porosity by Neutron tool are very much affected by the significant presence of clay minerals in the formation. Other porosity tools (Density and Sonic) are also influenced by the presence clay minerals. In shale reservoir, there is a very significant content of clay minerals. And hence estimation of realistic porosity rather effective porosity is very challenging in shale reservoirs and not possible with these three porosity tools. In this context, the NMR tool is very effective in providing realistic estimation of porosity as the tool is capable of proving lithology-independent measurement and also it can provide a separate estimation of capillary bound fluid porosity and free fluid porosity.

Schlumberger has developed CMR-Plus (Combinable Magnetic Resonance) tool for measurements based on NMR (Schlumberger 2014). Recording of CMR-plus was carried out at few wells covering the entire Cambay Shale in the Cambay Basin, India, for evaluation of reservoir characteristics of Cambay Shale. CMR log from one such well has been discussed here. In the studied well, the CMR log indicates that the main contribution to the porosity is from small pore porosity and capillary bound fluid porosity. Only small contribution in porosity is observed from free fluid porosity and also, free fluid porosity is not observable in the entire thickness of the Cambay Shale formation. The CMR estimated total porosity is varying in the range (of 10–30%), whereas the free fluid porosity observed is in the range (0.5–4%). This indicates poor presence of macro-porosity and very low permeability. A small section of the CMR log recorded in a well has been shown in Fig. 10, along with other logs like Calliper, Gamma Ray, Neutron, Density and different resistivity measurement curves with different depths of investigations. The neutron porosity in this well is observed to be varying in the range (24–60%). The neutron porosity is reading very high because of effect of clay minerals (V_{CLAY} estimated by Litho Scanner log is in the range 28–70%) and is not reliable. The effective porosity of Cambay Shale in this well has been estimated from CMR log using suitable T2 cut-off and is in the range (of 2–13%). So, for unconventional shale reservoirs, NMR log can provide more accurate estimation of porosity compared to other porosity logs for realistic estimation of hydrocarbon reserve.

4.4 Permeability Estimation

One of the most important applications of NMR logging is the ability to estimate the continuous permeability of the formation. However, NMR logging is not providing a direct continuous measurement of permeability. But estimation of the permeability of the formation is derived from the porosity distribution measurements using suitable permeability models. These models are based on a combination

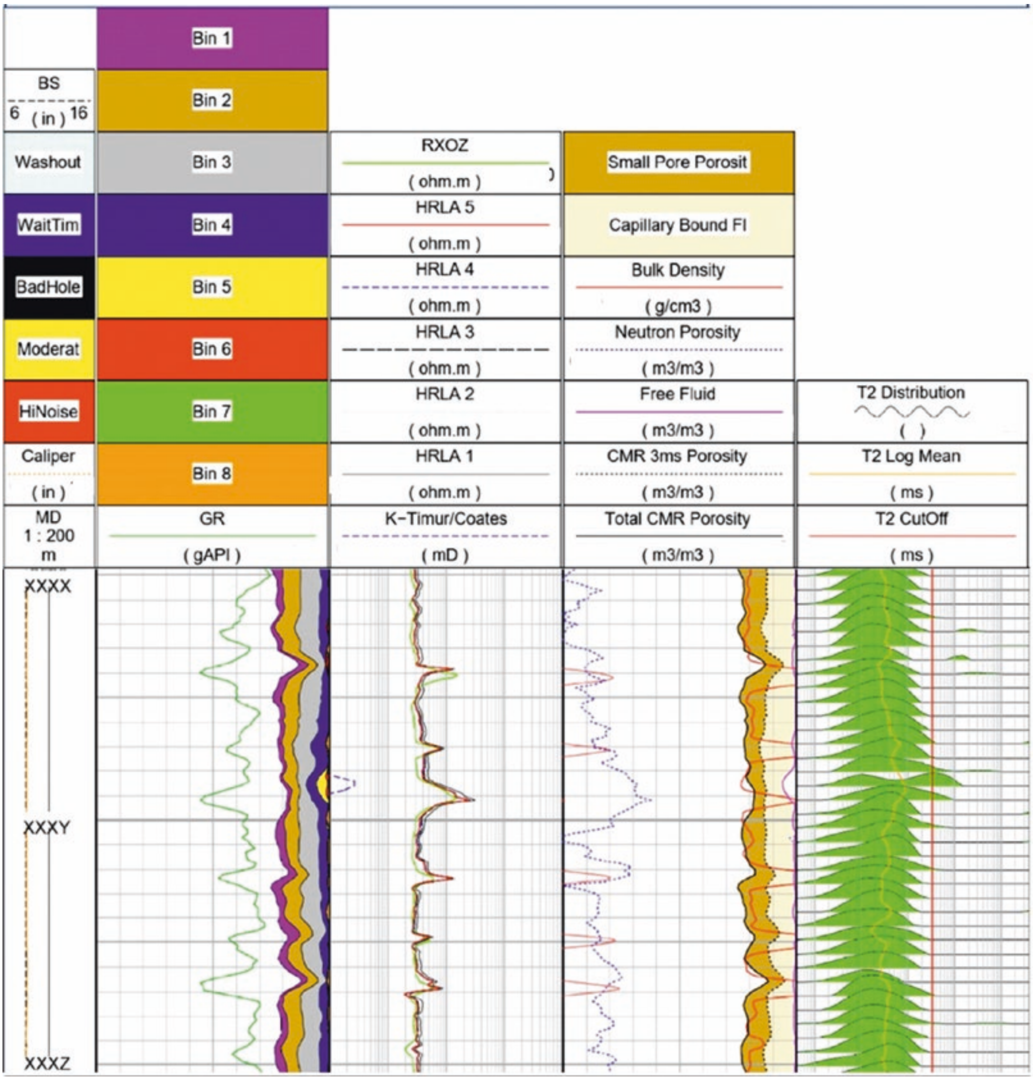

Fig. 10 A small section of CMR log recorded in a well at Cambay Basin against Cambay Shale

of theoretical and empirical relationships. Some permeability models have been developed. But two models are generally used: (i) the free-fluid (Timur-Coates or Coates) model, and (ii) the mean-T2 [the Schlumberger-Doll-Research (SDR)] model (Timur 1968; Coates and Dumanoir 1973; Kenyon et al. 1988; Bryant et al. 1993).

The Timur-Coates model based on the free-fluid index can be applied to both water-saturated and hydrocarbon-saturated reservoirs. Whereas, the SDR method based on the mean-T2 model can be applied to water-saturated reservoirs (Marschall et al. 1997). In both these models, it is assumed that a good correlation exists among porosity, pore-body and pore-throat size, and pore connectivity. In clastic (sand/shale) sequences, this assumption is generally valid and but for other lithologies, permeabilities derived from these models may not be reliable. The accuracy in permeability estimation from the NMR log can be improved by correlating with core-derived values of permeability. The permeability in the studied well of

Cambay Basin has been estimated by using the Timur-Coates model because of the presence of hydrocarbon in the shale formation. The permeability estimated from the CMR log is in the range (of 0.0000–0.79007 mD).

5 Conclusion

Well logging is playing a vital role in the exploration and exploitation of hydrocarbon resources. For unconventional shale hydrocarbon resources, it is much more difficult and challenging to have economically viable hydrocarbon production because of the complex petroleum systems with very poor porosity and ultra-low permeability. Here, application of appropriate advanced technology is very much essential for successful exploitation of shale resources. In recent times, there is a significant development in well logging services with the induction of some advanced logging tools to provide more data and information to geoscientists, drilling engineers and reservoir engineers for a better understanding of the reservoir and reduce complications during drilling to production stage. For shale reservoirs, estimation of parameters related to source quality, reservoir quality, and completion quality are very much needed for proper evaluation of resources. Hence, continuous estimation of these parameters are essential to identify potential zones (sweet spots) within thick shale formation to be targeted. Continuous estimation of these parameters is only possible with well logs. Fortunately, with the advancements in well logging technologies, some innovative tools are now available for continuous estimation parameters for evaluation of SQ, RQ and CQ. In this chapter three such advanced well logs like, Litho Scanner, Sonic Scanner, Nuclear Magnetic Resonance have been discussed which will be useful to have better understanding and evaluation of shale reservoirs. Well log like Litho Scanner can be used for the continuous mineralogical analysis of the formation. Litho Scanner (developed by Schlumberger) provides a direct continuous measurement of TOC, an important SQ parameter. Litho Scanner log can also be used for the continuous mineralogical analysis of the formation. Mineralogical composition is significantly controlling RQ and CQ. Brittleness Index (BI), a key CQ parameter can be estimated continuously by using mineral-based BI. Sonic-scanner (developed by Schlumberger), new acoustic scanning platform, has been designed to provide cutting-edge types of acoustic measurements for useful information about the drilling environment, the reservoir mechanical properties and hydro-fracture operation at the completion stage. Such information supports making decisions that reduce overall drilling costs, improve recovery, and maximize hydrocarbon production. Continuous BI can be estimated using Sonic Scanner log. Sonic Scanner log data can also be used for analysis of anisotropy and open fractures in the formation. Nuclear Magnetic Resonance log is another advanced log very useful for providing information for reservoir characterization and analysing producibility of the reservoir. NMR log is now extensively used to get lithology independent effective porosity and an estimation of continuous permeability. Application these logs will provide better understanding and various information to evaluate the resources for hydrocarbon exploitation in a time efficient and cost-effective manner.

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Emerging Unconventional Energy Resources Shale Gas Potential in Indian Sedimentary Basins

Veluri Keshav Rao

Abstract

Shale gas can be trapped within the natural fractures or pore spaces or as adsorbed gas on the organic matter in the shale formations that also act as the source rocks. India has a number of sedimentary basins from Proterozoic to Cenozoic. Five onland sedimentary basins have been identified with potential shale gas accumulations. They are: Cambay basin, Gondwana basin, Assam-Arakan Basin, Krishna-Godavari Basin and Cauvery basin. The regional geology, stratigraphy with shale thickness, tectonic setup and important parameters of Total Organic Carbon content (TOC), Vitrinite Reflectance (Vro), Gas Concentrations and Kerogen type are discussed for each of these basins. A concerted geoscientific effort is needed for the delineation and assessment of shale gas prospects to augment the exploration and exploitation activities. The current status of Shale Gas exploration and exploitation is synthesized and prognosticated Estimates of about 540 TCF of shale gas potential is indicated for these basins.

Keywords

Shale gas · India · Cambay Basin · Gondwana · Assam Arakan · Krishna Godavari

1 Introduction

India is poised to shift to a sustainable gas-based economy by augmenting domestic gas production in the years to come through conventional and nonconventional exploration ventures. Towards this goal, the prospects of unconventional Shale gas resources in different sedimentary basins which are endowed with immense Shale gas accumulations need to be explored and exploited. Methane in shales is generated from the transformation of organic material by bacterial (biogenic) and geo-chemical (thermogenic) processes. The gas so generated gets stored by multiple mechanisms as free gas in micropores and as sorbed gas on the internal surfaces. Thus shale gas is a combination of sorbed gas and micropore gas. Shale gas is accumulated in fine grained sedimentary rocks. Unlike conventional natural gas, shale reservoirs have very low porosities ($< 10\%$), low permeabilities(< 1 md) and have heterogenous mineralogical composition. The hydrocarbon generating capability in shales is controlled by total organic carbon content (TOC),thermal

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maturity, orbed gas content and shale reservoir thickness. Among the sedimentary basins, five on land basinal parts are rated as potential shale Gas prospect areas. They are Cambay Basin, Gondwana Basin, Krishna-Godavari Basin, Cauvery Basin and Assam-Arakan Basin (Fig. 1). Additionally, the Gondwana basin and Cambay Basin coals have potential of Coal Bed Methane and currently commercial CBM at the rate of 1.79 MMSCM per day is being produced from Gondwana fields of Raniganj blocks and Sholapur West block.

Realizing the importance of tapping this unconventional gas resources, a Policy

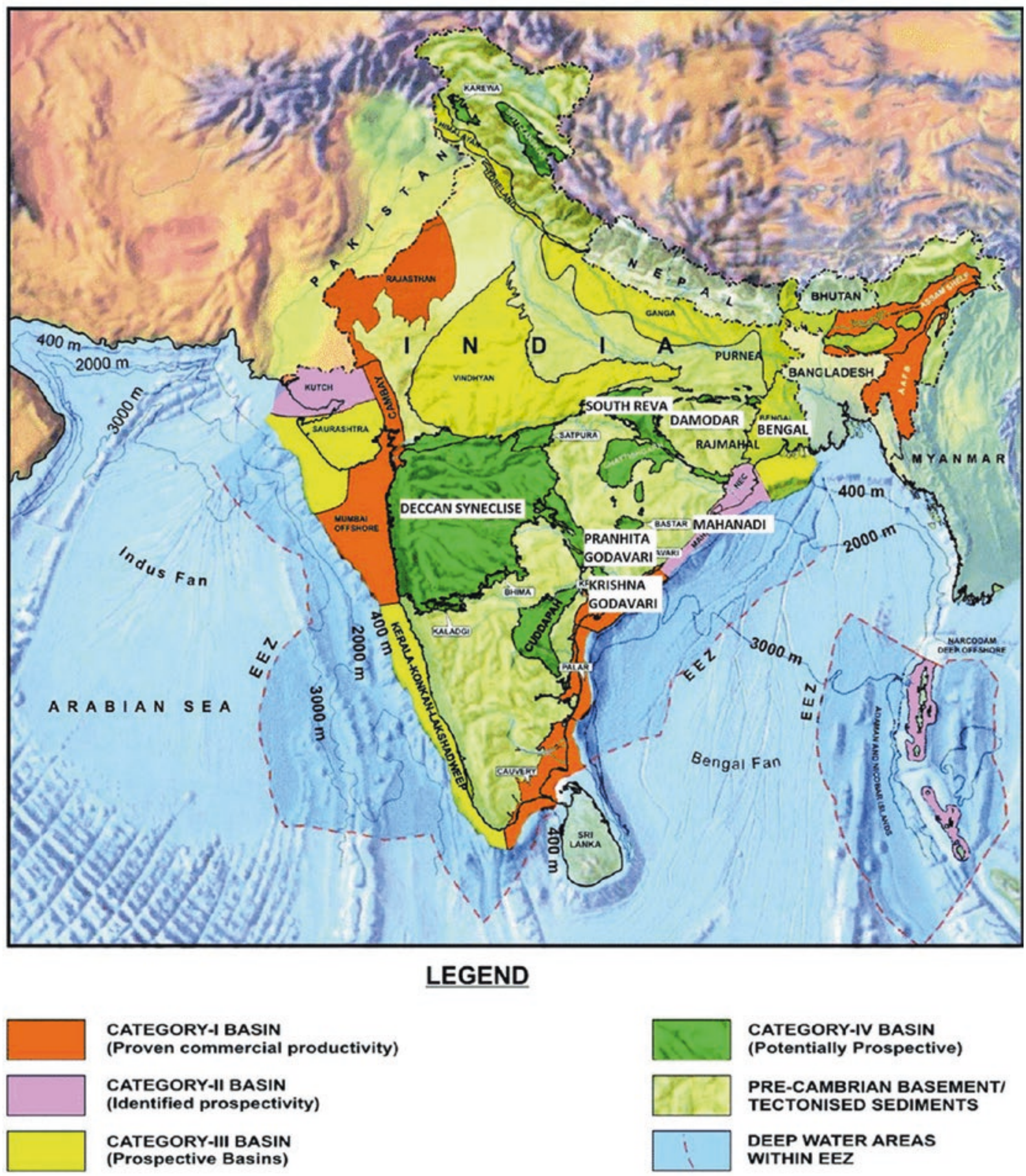

Fig. 1 Prospective shale gas basins of India (Director General of Hydrocarbon public domain)

framework was formulated by Government of India in 2013, exclusively to explore shale gas. Altogether 50 wells have been identified in four prospective basins Viz: Assam-Arakan basin, Krishna-Godavari basin, Cauvery basin and Cambay basin to be drilled by ONGC (Oil & Natural Gas Corporation). Additionally six blocks were identified in Jaisalmer and Rajasthan basins to be drilled by OIL (Oil India Limited).Till date 29 wells have been drilled by ONGC in four basins and OIL has completed drilling of two wells in its two basins. The presence of shale gas was established by ONGC when the first R&D well was drilled by Schlumberger in Gondwana formations of Damodar valley basin. Shale gas flowed from the Barren measures at 1700 m depth. The estimated resources were around 48 Tcf but could be prognosed to 100TCF. Subsequently in Jambusar block of Cambay basin another pilot well was drilled to explore presence of Shale gas. The well yielded shale gas from Cambay shale sequence at a depth of 2500 m. The estimated resources were around 20 TCf but could be prognosed to 60 Tcf.

2 Shale Gas Potential and Challenges

2.1 Cambay Basin

The Cambay Basin located on the western margin platform of Indian craton is an intracratonic rift graben basin. The basin covers an areal extent of 53,500 km^2 trending NNW-SSE. This is essentially a Tertiary Basin bounded by well demarcated basin margin step faults on its western and eastern margins.

Five tectonic blocks have been identified in the Cambay Basin separated by distinct Fault trends these are from north to south: Sanchor-Patan block, Ahmedabad-Mehsana block, Tarapur-Cambay block, Broach-Jambusar Block and Narmada Fig. 6: Tectonic Blocks of Cambay BasinTapti block.

Shales in Stratigraphy: More than 7000 m thickness of Tertiary sediments is observed in Cambay Basin overlying the Deccan trap Basement. However, the dominant shale units are: Olpad Formation of Paleocene age, Older Cambay shale unit of Paleocene-Lower Eocene age, Younger Cambay shale unit of Lower Eocene age followed by Kalol Formation of Mid Eocene age and Tarapur Shale unit of Upper Eocene–Oligocene age.

The Cambay shale Formation has good prospect potential for shale gas in view of its huge thickness, good TOC content and thermal maturity. Evaluation of these source rocks on the hydrocarbons generated and expelled further gives credence to the assumption that remnant hydrocarbons are entrapped in the generation lithologies as shale gas. Salient hydrocarbon generation characteristics of encountered shales for different stratigraphic units are summarized in the Table 1. Estimated potential of about 95 TCF is estimated for Cambay Basin. However a prognosticated potential of 184 TCF could be drawn based on thick shale formations, available data from conventional wells drilled and analogous assumptions.

2.2 Krishna-Godavari Basin

The Krishna-Godavari Basin is a pericratonic rift basin located on east coast of India extending into offshore waters. The sedimentary fill is around 7000 m of which about 4000 m constitute Tertiary fill and the rest is Proterozoic and Mesozoic sediments. The general structural trend of the basin is NE–SW. Tectonically, down to basement faults have defined a series of five horst—graben features viz; Bapatla Horst, West Godavari sub Basin, Tanuku horst, East Godavari sub basin, and Eocene Shelf edge (Fig. 2).

Shales in Stratigraphy: More than 7000 m of thick sediments of Proterozoic to Recent age are observed in KG Basin Overlying the Achaean Basement. The dominant shale units are:

Table 1 Salient hydrocarbon generation characteristics of encountered shales for different stratigraphic units

Formation	Thickness (m)	TOC %	VRo %	Gas conc. Bcf/m^2	Kerogen type
Olpad	100–>1000	1.5–4.0	0.60–0.75	No Data	II & III
Older Cambay Shale	500–1200	1.5–4.0	0.75–1.2	231(US EIA Report)	II & III
Younger Cambay Shale	520–1500	1.0–4.0	0.75–0.85	231(US EIA Report)	II & III
Tarapur	60–400	1.00–1.2	0.53	No Data	II & III

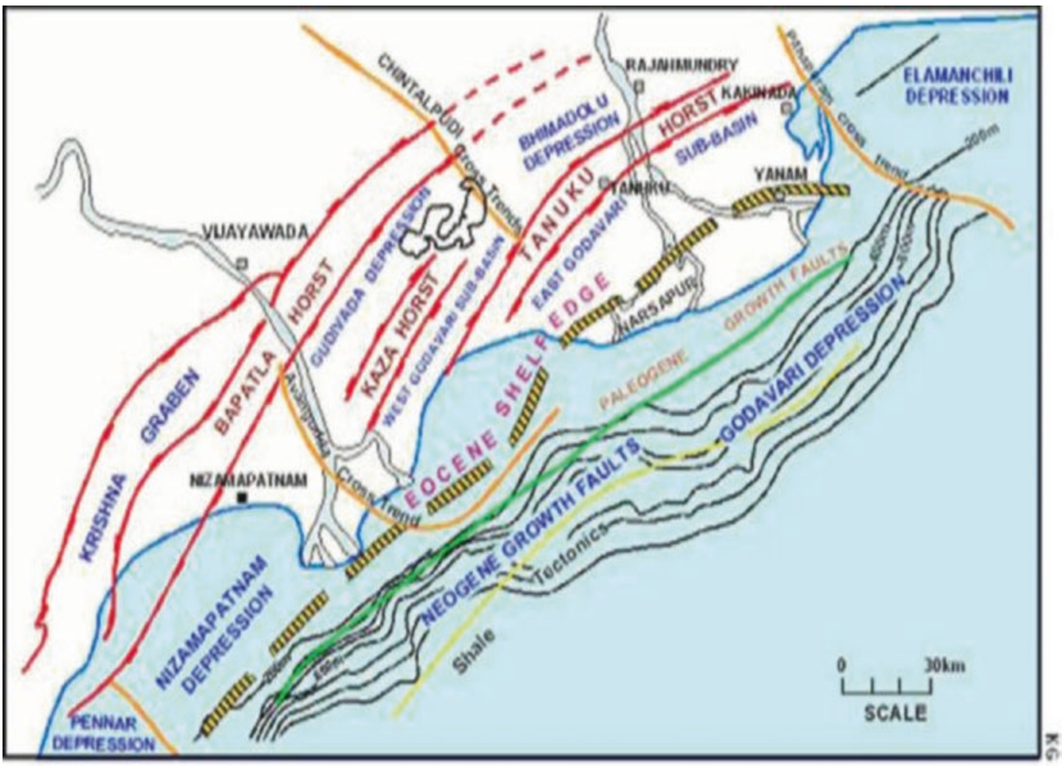

Fig. 2 Tectonic elements of Krishna–Godavari Basin (modified after Rasheed et al. 2013)

Kommugudem shales of Permo-Carboniferous age, Raghavapuram Shales of Lower to Upper Cretaceous age, Palakollu shales of Paleocene age and Vadaparru shales of Lower Eocene age. Of these, Kommugudem shales and Raghavapuram Shales could be most promising shale gas reservoirs. The Kommugudem and Raghava Puram Shales hold promise of good shale gas accumulations by virtue of their Characteristic parameters.

Table 2 summarizes some of the salient parameters of Shales in Krishna–Godavari Basin for different Formations. Prognosticated resource potential of about 136 TCF has been estimated for this basin based on analogous data in other parts of the world. (Sahu 2010).

2.3 Cauvery Basin

Cauvery Basin located on the south eastern part of India extending into offshore part is an intracratonic rift basin situated between two cratonic masses viz; Indian Peninsula in the

Table 2 Shale characteristics of identified Formations in K-G Basin

Formation	Thickness (m)	TOC %	VRo %	Gas Conc Bcf/m^2	Kerogen type
Vadaparru	>400	4.0–6.75	–	No Data	II & III
Palakollu	>500	0.6–23.0	0.35–0.40	No data	II & III
Raghavapuram	200–>1800	1.5–4.20	0.9–1.30	143	II & III
Kommugudem	300–900	1.41–5.30	1.00–1.30	156	II&III

northwest and Sri Lankan massif in the south-east. The basin covers an aerial extent of 25,000 km^2 in the onland part and another 30,000 km^2 in the shallow offshore part. The basin extends into deep waters of Bay of Bengal covering an additional 40,000 km^2 of area. The general structural trend of the Basin is parallel to the Pre-Cambrian Eastern Ghat structural grain.

The Basin is divided into a number of sub-parallel horsts and graben, trending in a general NE-SW direction which formed as a result of fragmentation of the Gondwanaland during drifting of India-Sri Lanka landmass system away from Antarctica/Australia continental plate in Late Jurassic/Early Cretaceous. The initial rifting caused the formation of NE-SW horst-graben features. Subsequent drifting and rotation caused the development of NW–SE cross faults. More than 6000 m thickness of Mesozoic and Tertiary sediments is observed in Cauvery Basin overlying the Archaen Basement. Sattapadi Shale unit of Uttatur Group, Kudavasal Shale unit and Portnovo/Komorakshi shales of Ariyalur Group and Karaikal shales of Nagore Group are the dominant shale units.

The Sattapadi and Komarakshi shales are organically rich and are found to be thermally mature. These may have generated good hydrocarbons. The Andimadam/Sattapadi Formations of Uttatur Group have good resource play with an areal extent of 12,000 km^2 having TOC values(> 10.7%)and VRo of 0.7–1.0. Table 3 summarizes some of the salient parameters of Shales in Cauvery Basin for different sub basins. Prognosticated resource potential of about 80 TCF has been estimated for this basin based on analogous data in other parts of the world (Sahu 2008).

2.4 Gondwana Basin

The Gondwana System is the most extensive continental facies of Permo-Cretaceous age with development of coal shale and sandstone sequences of more than 10,000 m thickness**.** These sequences are present in Damodar-Koel valley in Bihar/Jharkhand, Son–Mahanadi Valley of Orissa, Rajmahal Purnea–Rewa basins Satpura-Pranhita–Godavari valleys of Maharashtra/Andhra Pradesh of peninsular India (Mukhopadhyay et al. 2010). Oil & Natural Gas Corporation (ONGC) has created an exploration landmark in pursuit of its first shale gas exploration. In the R&D well (RNSG#1) in Damodar Valley Basin drilled to target depth of 2000 m, the well has flowed gas from the Barren

Table 3 Shale characteristics of identified formations in Cauvery Basin

Formation	Thickness (m) Approx	TOC %	VRo %	Gas Conc Bcf/sq mi	Kerogen type
Karaikal	250–750	0.31–2.78	1.15–1.20	143*	II & III
Portonovo	200–340	0.31–4.76	0.65–0.79	No Data	II & III
Kudavasal	800–1100	1.68–2.00	0.34–0.55	143*	II & III
Sattapadi	300–500	1.50–1.75	1.0–1.12	No Data	II & III

Measures sequence at about 1700 m depth. The Barren Measure shales are 858 m thick in the well drilled.

Prospect of Shale Gas:
Table 4 summarizes some of the salient parameters of Shales in Damodar Valley, South Rewa and Pranhita Godavari sub-Basins.

ONGC has recently drilled four pilot wells in karanpura and Damodar valley basins of valley of which one well in Damodar basin has been extensively tested by hydrofrac jobs. Shale has has flown to the surface and GIP of 48 Tcf has been estimated for the Damodar valley Basin by Schlumberger, which had undertaken the Pilot project on turn key basis. A prognosticated Resources of 85 TCF is estimated for the Gondwana basin.

2.5 Assam-Arakan Basin

The Assam-Arakan Basin is a Polyhistory basin spreading across the northeastern part of India, Eastern part of Bangla Desh and western part of Myanmar. The three major tectonic elements of the basin are: the Assam Shelf, the Naga Schuppen belt and the Assam-Arakan Fold belt. The Indian part of the Basin covers the States of Manipur, Mizoram, Nagaland, Tripura, Assam and Basin is a shelf-slope-basinal system. The shelf part of the basin spreads over the Brahmaputra valley and the Dhansiri valley, the latter lying between the Mikir hills and the Naga foothills. From the Digboi, the shelf runs westward to the southern slope of the Shillong plateau. The shelf-to-basinal slope, i.e., the hinge zone lies below the Naga schuppen belt. The basinal part is occupied by the Cachar, Tripura, Mizoram and Manipur fold belts. The shelf part rests on Precambrian granitic basement, whereas the basinal part lies on transitional to oceanic crust. The area within the Upper Assam shelf, having high petroleum potential, measures approximately 56,000 km^2 and contains about 7000 m thick sediments of mostly Tertiary period, and the area in the basinal part with moderate to high hydrocarbon potential measures about 60,000 km^2 and contains more than 10,000 m thick sediments of mostly Tertiary period.

Stratigraphy of the basin

More than 10,000 m thickness of Tertiary sediments is observed in Assam-Arakan Basin overlying the undifferentiated Cretaceous/metamorphic Basement complex. However the dominant shale units are: Upper Disang Group of Sediments of Paleocene-Eocene, Kopili Formation of Jaintia group (Eocene age), Jenam Formation of Barail Group of Oligocene age, Bhuban and Bokabil Formations of Surma Group (Miocene age).

Sedimentary sequences ranging in age from Late Mesozoic to Cenozoic are exposed in the Assam-Arakan Basin. The sequences can be divided into shelf facies and basinal (geosynclinal) facies. The shelf facies occur in Garo

Table 4 Shale characteristics of Gondwana basin Formation in Damodar valley

Sub basin	Formation	Thickness (m)	TOC %	VRo %	Gas conc Bcf/sq mi	Kerogen type
Damodar Valley***	Raniganj	>600			123*	
	Barren Measures	>800	4.0–10.0	1.0–1.2		III
South Rewa	Raniganj	800–1250	5.0–18.40?	0.40–0.60	123*	III
	Barren Measures	140–600	DA**	DA**		
	Barakar	150–900	5.06–14.72	0.40–0.60		III
Pranhita Godavari	Upper Gondwana	900–1100	DA**	DA**		
	Lower Gondwana	400–550	6.41	0.67		III

** Data not available *** ONGC drilled Pilot wells in Damodar & Karanpura sub basins hills, Khasi-Jaintia hills, parts of North Cachar hills and Mikir hills, and below the alluvial cover in Upper Assam, Bengal and Bangladesh. The basinal facies occur in the Patkai range, Naga Hills, parts of North Cachar hills, Manipur, Surma valley, Tripura, Chittagong hills of Bangladesh and Chin hills of Myanmar (Burma).

Lithostratigraphy of Assam-Arakan basin is complex and shales in the stratigraphic sequences are located at different depths in different formations (Table 5).

Prospect of Shale Gas:
From the foregoing, it can be surmised that the Jenam, Bhuban and Bokabil Shale units have good prospect potential for shale gas in view of its huge thickness, good TOC content and Vitrinite reflectance. The total organic carbon and maturation studies suggest that shales of the Kopili and Jenam formations also are organically rich, thermally mature and have generated oil and gas in commercial quantities. Further evaluation of hydrocarbons generated and expelled may offer credence to the assumption that remnant hydrocarbons are still entrapped in the generation lithologies and can be explored and developed. Prognosticated potential of about 55 TCF is estimated for Assam-Arakan Basinal part of India based on available data and analogous geological assumptions.

3 Prognosticated Estimates of Shale Gas in India

Various Agencies –EIA (USA), McKinsey, USGS, NGRI, Schlumberger, Petrotech Veterans Forum and others have estimated varied shale gas resources for different basins, based on their evaluations, presumptions and analogous situations. An optimistic total of 540TCf is prognosticated for the five basins where exploration data while drilling for conventional reservoirs is available to limited extent (Table 6).

It is imperative that the figures of prognostications are converted into geological estimates and then finally into recoverable reserves. I would say that these resources are still underdeveloped. Thus an accelerated programmed requires to be drawn by the Government on multiple ways to explore and exploit these resources.

Table 6 Shale gas resources in different basins in India (Boruah 2014; IEA 2021; Rao 2013; Rao 2020; Rao 2018)

Basin	Resources prognosed (TCF)
Cambay	184
Krishna-Godavari	136
Cauvery	80
Assam Arakan	55
Gondwana	85

Table 5 Summarizes some of the salient parameters of Shales in Assam-Arakan Basin for different Formations (IEA USA, 2021)

Formation	Thickness (m)	TOC %	VRo %	Gas Conc Bcf/sq mi	Kerogen type
Up. Disang Gp	250–400	1.69–1.94	0.90–1.94	120*	II & III
Kopili	>500	1.0–4.2	0.92–1.44	No Data	II & III
Jenam	900–1200	2.5–4.5	0.64–1.20	No data	II & III
Bhuban	800–1000	0.31–1.36	0.90–1.0	120*	II&III
Bokabil	400–1000	0.64–2.4	0.57–0.62	No data	II & III

* US EIA Report

4 Conclusions

The success of shale gas exploration and production in USA has evoked keen interest around the world in evaluation of shale gas reservoirs. Although shale rocks occupy a large part of Indian sedimentary basins and could form significant shale gas generation and production potential, they are underexplored in terms of evaluation of geological, geo-chemical, geophysical and petrophysical parameters. The challenges are multifold. Some of them to be cited are: acquision of geological, geo-chemical, geophysical and petrophysical parameters by drilling pilot wells for identification of sweet spots in stratigraphic columns because of their varied heterogeneities,: Development of right models to suit Indian needs through innovative technologies by forging partnerships with globally advanced companies, Tackling environmental externalities within geographic entities with focus of dense population areas among others. In order to explore and exploit these Unconventional resources, a review and reassessment of evaluation is warranted by adopting innovative technologies in seismic data acquisition and interpretation along with specific and critical laboratory investigations on shales with the help of technologically advanced global companies.

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Enhanced Gas Recovery (EGR) in Shale Gas Reservoirs

Vamsi Krishna Kudapa, T. K. Dora and Ponmani Swaninathan

Abstract

The generation of energy in the United States is considerably aided by the country's abundant shale gas resources. Combustion of fossil fuels is the source of greenhouse gas emissions. Potential sources of greenhouse gas emissions include power plants, oil refineries, and flaring or venting of generated gas (mainly methane) in oilfields. Not only can the commercial usage of greenhouse gases in shale reservoirs lead to an improvement in oil or gas recovery, but it also helps to contribute to the sequestration of carbon dioxide. Because of the enormous gas reserves that are believed to exist around the globe, shale gas is currently being extracted in various nations and is therefore regarded as one of the most reliable sources of energy. Shale reservoirs are naturally fractured, and for this reason, it is necessary to consider two separate systems: the matrix and the fracture. Implementation of improved recovery techniques is required in order to make the production of gas from shale reservoirs economically viable. This chapter's primary objective is to provide an overview of improved gas recovery methods applicable to shale reservoirs. In the first portion, it gives a detailed explanation on shale and enhanced gas recovery (EGR), and then it discusses the characteristics and flow behaviour of shale gas in the second section. Both the continuous CO_2 injection approach and the huff-n-puff CO_2 injection technique are reviewed in relation to the mechanism of enhanced gas recovery as well as the problems that were faced during the process of gas recovery.

Keywords

Shale gas · Huff-n-puff method · Enhanced gas recovery · Gas storage · Adsorption · Absorption and Challenges

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1 Introduction

Shale is mostly made up of small, tiny layers that are held together by a thin layer. Shale is a type of layered stone that forms when mud is buried deeply and different minerals, like clay

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minerals and tiny pieces of quartz and calcite, combine with each other. Shales are put into different groups based on how their mineralogy, grain size, breaking, and pore structure change on a submillimeter scale. The size of the pores in shale gas storage spots ranges from nanometers to very small scale. Shale gas reserves have been found at depths between 250 feet and 8000 feet. The depth of a shale gas reservoir should be between 300 feet and 600 feet for it to be a good idea (Aguilera 2016). Shale gas supplies from better places are very different when it comes to the underlying natural and mineral composition and the thickness of the profitable layer. Characteristics of the shale gas supply from same reservoir are not the same and this inconsistency in shale gas properties has a big effect on well productivity, which should be considered to increase gas production (Li et al. 2017). Organic matter is buried deep within thermogenic shale gas reservoirs. Due to higher temperatures in these deeper levels, organic matter is enough cooked to produce dry gas like that seen in shales. Since most of the TOC is turned into shale gas, the amount of TOC in thermogenic shale gas is usually less than 2% wt. These supplies can be easily broken up, so they are not called fractured shale gas reservoirs. Instead, they are called fractural shale gas repositories. During the first year of production, the supply will be reduced more rapidly due to the higher gas content in the pores. Production will thereafter level out and drop by a type B-factor, which is greater than 1. As these supplies are not very porous, they will continue to produce gas for a very long time before the pressure in the reservoir drops significantly away from water-driven fractures. In thermogenic shale gas deposits, dry gas is king because these supplies are found at higher temperatures, such as at depths of more than 3000 feet (Javadpour and Fisher n.d.). Thermal shale gas reserves have high initial production rates but rapidly diminishing yields because of a variety of factors, including a decrease in supply pressure, a decrease in porosity due to the decrease in pore pressure, and a decrease in fracture flow tendency. To get enough hydrocarbons, organic matter has not gotten deep enough into the reservoir, which represents that maximum amount of organic matter has absorbed most of the gas. The microbes that are transported into the rocks by the water are directly responsible for the gas that flows out of these supplies. The TOC content in these reservoirs is very high, for example, more than 10% wt. since the natural gas production is so low. In this case, having an open natural fracture is very important because it controls how much water and gas can be made. Because of the shallow depths, lower gas formation, and the removal of water from fractures before releasing the gas, thermogenic shale gas repositories have lower flow rates and EURs (Ross and Bustin 2009). By lowering the reservoir's pressing factor through free gas recovery, the initial stage of production is met, which then promotes the desorption process that diffuses gas from the rock surfaces. It was demonstrated that the partial pressure of methane cannot be set to zero in fractures due to financial constraints because the gas discharge from shale grid into fracture framework in those reservoirs is constrained by the gas partial pressure gradient in comparison to a pressure gradient inside the reservoir (Puri and Yee 1990). High gas production from the supply requires maintaining two crucial slopes: the methane partial pressure gradient between the matrix and fracture framework, and the reservoir pressure inclination between the fracture and production wellbore. The introduction of an unfamiliar gas to the shale gas supply, more precisely an enhanced shale gas reservoir (ESGR) measure, was proposed in the mid-1990s because such conditions are not achievable by normal consumption (Sayyafzadeh et al. 2015). Enhancing reservoir flow tendency is another strategy for increasing gas production from shale resources. The most well-known techniques for increasing efficiency in shale reservoirs involve pressure-driven stimulation operations, such as natural and hydraulic fracture stimulation.

2 Shale Gas Reservoir Properties

The key characteristics of these reservoirs diverge somewhat from conventional reservoirs due to the innovative conduct of shale gas supply in terms of gas storage and production methods. The flow tendency of the primary fracture and fracture network, the distribution of the proppant inside the complex fracture system, and the impact of the adsorbed gas mechanism are the major parameters in shale supplies that are taken into consideration while looking at reservoirs.

2.1 Fracture Flow Tendency

The flow tendency of the pressing force-driven fracture framework, which depends on the proppant stream in the break framework, is a crucial component that affects the formation profile in the broken reservoir. Depicting the break framework and the primary hydraulically produced fracture as accurately as feasible is thus one of the requirements when presenting from shale gas supplies. Additionally, a fundamental component of well introduction is seen in the distribution of the proppant within the complicated fracture structure and the inclination of the hydraulic fracture to flow. Cipolla et al. studied the impact of two proppant conveyance scenarios on wellbore performance: (1) evenly dispersed proppant and (2) packed proppant in the primary crack. In the most recent instance, the initial fracture interacts with the matrix of the un-propped crack. Overall, the inclination of an un-propped network flow may limit the formation. When the break matrix might have been propped equally, the proppant concentration was insufficient for practical output. Therefore, the un-propped fracture flow propensity may increase the profitability of the wellbore; yet, even productive conveyance requires a significant amount of proppant. However, the usual proppant fixation is high in the original fracture when the proppant has been confined to the main fracture. The result is a significantly increased probability for common fracture to flow and a better relationship between the break matrix and the wellbore, both of which have a significant positive impact on profitability. Repositories with a tight fracture cannot have depleted productively when the matrix crack flow tendency is extremely low, according to mathematical reproduction reads for a variety of matrix break flow tendency ranges. The increase of break network conductivities more than 50 md-ft was unusual for the gas production industry. Accordingly, it had concluded that in order to increase production rate for tight cracked arrangements with fracture penetrability's in the region of 0, 1 d, break matrix. Conductivities equivalent or greater than 50 md-ft are required (Cipolla 2009). Cipolla et al. (2009a, 2009b, 2009c) also covered the effect of crucial fracture flow tendency on production profile. The very near fracture seepage can be quite effective when a previous break is present and has been well supported. When the earlier crack flow tendency is 20 md-ft, gas recovery can be completely accelerated, though the critical flow tendency beyond 100 md-ft only offers negligible steady benefits. However, it may not always be possible to generate low-thickness liquid with such a high flow tendency throughout the entire matrix. Unexpectedly, the seepage is less sufficient and the reservoir pressure remains consistently higher when the crucial break flow tendency is minimal, illustrating helpless gas recovery. Finally, it was discovered that the production signature becomes identical to that of a high flow tendency critical break linked with a low flow tendency break matrix when the matrix fracture flow tendency increases up to 500 md-ft (Cipolla et al. 2009a, 2009b, 2009c).

2.2 Role of Fracture-to-Fracture Separation

The number of crack treatment stages will determine how much spacing between fractures is necessary; an increase of a few stages causes previous fractures to separate closer together.

As previously said in the previous section, if the crucial high conductivity break can be created, then the crucial crack splitting becomes irrelevant. Additionally, reducing the necessary crack separation by increasing the number of fracture treatment phases will significantly affect formation rates and gas recovery. Mathematically, the impact of necessary crack separation on production profiles was investigated and compared to data from two Barnett shale level wells with 500–600 foot-long breaks. Production from the wells followed a pattern of 2 md-ft consistent flow tendency matrix and a crucial break that dispersed 500–600 ft. This model demonstrates that it is challenging to achieve high flow tendency initially, and that persistently conductive matrix significantly contributes to formation. In order to achieve ideal formation rates and gas recovery, the fundamental issue of crack dividing emerges (Cipolla et al. 2008).

2.3 Role of Shale Matrix Permeability

Numerous researchers have examined the impact of matrix permeability on the summary of production from shale gas deposits (Cipolla 2009). Grid penetrability decreases as matrix block size increases, as shown by mathematical formulae created through modelling. After 15 years of manufacturing replication, the formation increment for a 10-overlay modification in network porousness for a 50-foot square is merely 10% (Cipolla et al. 2008). This implies that if extraordinarily intricate break networks had been developed, tight framework squares would have to be properly drained. Stream systems in shale gas wells may also be impacted by the extremely low network penetrability. In multi-cracked wells, formation advances as the pressing factor waves go deeper into development. Pressure, waves from nearby crossover fractures will eventually encounter one another, and pressing factor impedance will occur. This is what defines the hour when the pseudo direct stream system progresses to the pseudo-consistent stream (Song et al. 2011). Significantly delaying the hour of impedance between adjacent cracks is caused by low grid porousness. Prior to the obstruction, the porousness has increased. Because of this, consumption occurs in super-low penetrability supplies before the pseudo-consistent state criteria are reached.

2.4 Role of Hydraulic Fluid Viscosity

To reduce crack unpredictability and promote planar fractures, water-driven fracture treatments are used in conventional gas supply. This enables the positioning of tall clusters of proppant necessary for financially viable formation. In any event, the methodology is quite distinctive in terms of shale gas supply. A significant amount of low consistency liquids are used in stimulation drugs in shale gas storage facilities to accelerate break unpredictably and identify low proppant fixations. Higher syphon rates are necessary to transfer proppant into the break in low consistency. Additionally, due to the cost of the polymers used to consistency the breaking liquids and the harm caused by polymer maintenance in such low porosity advances, traditional medicines are commonly uneconomical in shale arrangements (Cipolla et al. 2009a, 2009b, 2009c). With slick water of low viscosity, pressure driven fracturing of shale gas deposits is carried out. Slick water, which is used to crack shale formations, uses less polymer and is only slightly thicker than water. The majority of it is made up of water that has been “slickened” with various additives to lessen friction in the wellbore (Kostenuk and Browne 2010). When poor consistency liquids are used, the reservoir develops a wider, more limited fracture rather than the superfluous growth that is usually seen when high thickness, cross-connected liquids are used (Zahid et al. 2007). These low consistency liquid poor proppant conveyance characteristics are a negative. However, using low consistency liquids for cracking can reduce the successful break half-length due to stage catching in the setup. Change modifier added substance to the slick water liquid offered is another method for proppant transportation for slick water breaking (Kostenuk and Browne 2010). Each grain of the proppant is surrounded by tiny air pockets created by the additional material, which transforms the proppant into an aerophilic state. Because the proppant now has tiny air pockets, it is lighter and can move through slick water without being weighed down by a dense current. The improved means of transportation technique reduces proppant banks and settling in slick water shale cracking treatments overall. With that new method, the slick water proppant penetrates the arrangement farther without settling evaluated production data from Barnett shale, such as break and re-crack treatments. The examination was done on wells treated with cross-connected (XL) gel and water-fracs. Although the water-fracs increases gas production, the XL gel treatment showed production marks with larger break flow tendency than the water-fracs (Cipolla et al. 2009a, 2009b, 2009c; Kostenuk and Browne 2010).

2.5 Stress Effect on Permeability of Fracture Network

There is a high possibility that a significant portion of the fracture matrixes formed during stimulation therapy may be un- or just partially supported. According to an investigation of the relationship between conclusion stress and un-propped fracture flow potential, conclusion stress increases as Young's modulus decreases (Cipolla et al. 2008). Simulations are run to examine the impact of desorbed gas on different fracture-to-fracture separations. As a result, smaller grid sizes yield higher initial formation rates, whereas larger square sizes have no impact on the underlying production profile. Since the drawdown in the break network keeps growing during the wellbore life, stress-subordinate crack flow tendency always reduces gas production (Cipolla et al. 2009a, 2009b, 2009c).

The effect of Young’s modulus on the formation profile is the next goal. The impact of increasing conclusion weight on an un-propped or partially propped break flow tendency becomes more severe when Young’s modulus decreases (gentler stone). As the pressing factor drop in the crack matrix increases over time, resulting in helpless waste of the tight framework rock and essentially poorer gas recovery, at lower moduli, the break flow propensity is fundamentally reduced. In any event, the severity of the tendency for stress-subordinate cracks to flow may not be fundamental in the early stages of formation (Cipolla et al. 2009a, 2009b, 2009c).

3 Flow Behavior of Gas in Shale Gas Reservoirs

3.1 Mechanism of Gas Storage

Majority of shale gas repositories are composed of two separate permeable media, such as the shale framework, which holds the majority of the development’s gas storage but has very little porosity. Although the fracture matrix has a low stockpiling limit, some gas is stored there. The gas in the fracture will be immediately delivered during formation. Once its pressing factor is below the framework pressure, the adsorbed gas is then released from the arrangement. The capacity limit and the sorbed proportion of free gas in the reservoir are two parameters of the shale network. The amount of free gas in the shale supply was influenced by the shale’s zone, thickness, gas-filled porosity, and depth. Additionally, factors including the thickness of the shale and the amount of adsorbed gas determined how much free gas was there (Gong et al. 2011). Shale gas can be stored in two different states: free and adsorbed. The adsorbed gas is stored on the outside of the shale network molecule via adsorption, and the free gas is stored in both the regular fracture and the tiny pore space in the grid of the shale. Regular cracks and tiny pores inside the fracture provide free gas accumulation in shale gas reserves. In this way, the double porosity framework can be used to represent the components of free gas storage. Major portion of free gas is stored in open fractures (Kalantari-Dahaghi and Mohaghegh 2011). In gas shale formations, a large amount of the gas storage is made up of adsorbent gas, which is held in place by a variety of actual components. A "Triple Porosity Model" is the greatest description of the gas storage component in a shale gas deposit since it incorporates both free gas and adsorbed gas. Having all the shale gas zones, such as in regular breaks, Matrix micro pores, and gas adsorption, is the main goal of using "Triple". The capacity system in the "Triple Porosity" Model for shale gas supply is shown in Fig. 1.

There is also the quad porosity structure for storing gas. The gas is stored in this structure in four separate porosities, as follows:

- Kerogen is a gas-wet porosity structure.
- An inorganic framework with water- or gas-permeable pores.
- This matrix of typical fractures repaired across the production process.
- Initiated break framework considering liquid flow through high penetrability channels (Ding et al. 2012).

3.2 Gas Transport Mechanism

Different modes of transport are used to move liquids across porous material. As a whole, gas transport will be completed by looking at three different modes of transportation: force, energy, and mass. Under isothermal circumstances, such as a constant temperature, mass exchange and diffusion are used to transfer gas

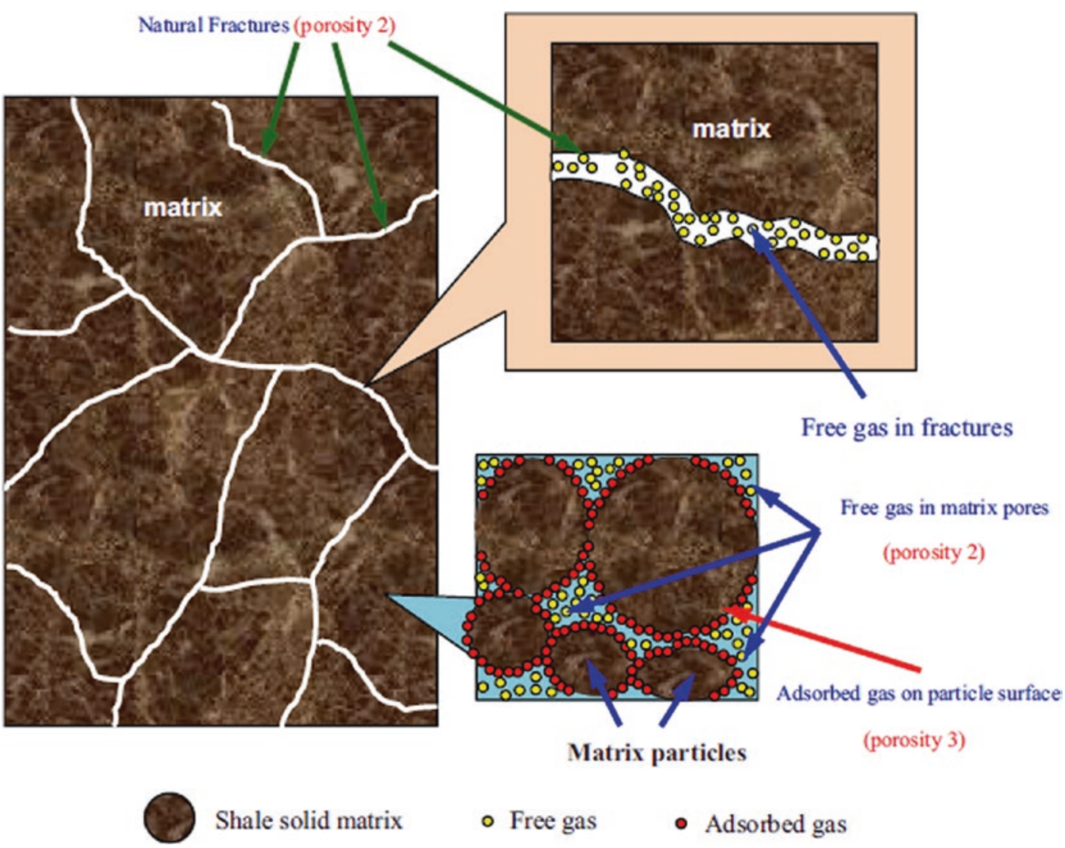

Fig. 1 Shale gas storage in triple porosity model (Zhao et al. 2013)

from shale reserves. Natural porosity is where most adsorption impacts occur. When water is accessible and injected into the shale during pressure driven cracking, gas dissolvability in water can be evaluated. When water is available, the idea of moving water through stone should be considered. Because of the nanometer-scale pore throat range, the thin pressing factor has a tremendous impact on liquid movement. Gravity has a greater effect on a flowing liquid when water is present (Swami 2013). Schepers (Swami 2013) at first did not demonstrate the dissemination of adsorption gas into the fracture framework and diffused into the fracture pore framework. Furthermore, the liquid stream inside the network miniature pore framework and the stream from grid miniature pore framework to fracture system is given by darcy-stream, which implies the progression of gas inside the permeable media, is a direct result of the pressing factor (Fig. 2).

In gas shales, Wang et al. (2009) listed pores and fractures as two types of permeable medium. Pores are partitioned into natural pores, non-natural pores, the breaks are partitioned into common fracture, and using pressurized water instigated breaks. The natural pore inside the fracture was accepted to go about as a permeable mechanism for the gas stream inside the network. Schepers expressed that the gas delivery and transport systems could be portrayed through desorption, dissemination and Darcy-stream. Besides, the permeable medium's stream is the predominant stream component than the stream by dissemination system.

The gas transport system in shale gas supplies is portrayed as follows.

(1) Free gas will move through grid pores (essential porosity) into the break framework (optional porosity) because of pressing factor contrast because of liquid stream in permeable media.
(2) Now, the free gas will stream to the wellbore through breaks. Fracture in the area across wellbore will allow the free gas to flow into the well.
(3) It is possible that adsorbed gas molecules could migrate from molecule surfaces into the pore space if pore pressure decreases, which is when desorption occurs for adsorbed gas.
(4) Adsorbed gas is now free gas and is transported in a similar manner as the first free gas. The stream component through fracture pore networks and fracture networks is also identical (Fig. 3).

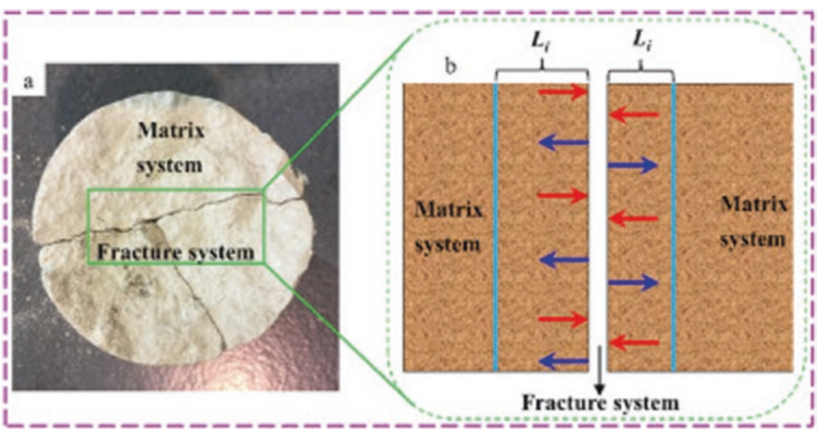

Fig. 2 Schematic representation of gas flow from shale matrix to fracture. The blue arrows represent the direction of water phase flow, and the red arrows represent the direction of oil phase flow (Liu et al. 2020)

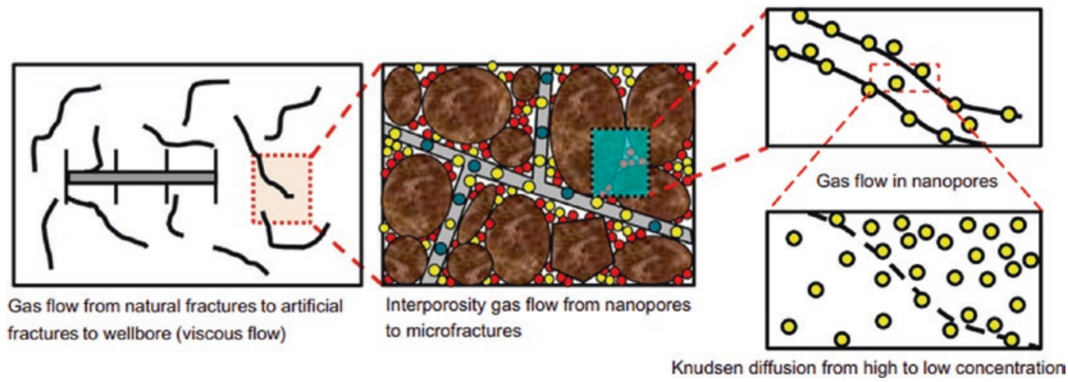

Fig. 3 Representation of gas flow mechanism in a shale gas reservoir (Zhang 2019)

3.3 Gas Adsorption Model

Gas adsorption is a surface phenomenon, an intermolecular bond. Langmuir's model is acceptable for evaluating gas adsorption/desorption.

$$V_{ads} = {}^{V_L P}\!/\!_{(P_L + P)} \quad (1)$$

V_{ads} = the amount of gas absorbed by a rock of unit mass.

V_L = Langmuir volume.

P_L = Half of the Langmuir volume is adsorbed at this Langmuir pressure.

P = Random pressure, psi.

No matter what type of gas adsorption limit you apply, temperature change is unaffected as assumed. Due to this assumption that temperatures are stable, the temperature was excluded from earlier equations. "Sorption Isotherm" refers to a visualization of the Langmuir equation based on this assumption (Arthur et al. 2009). The form of the sorption isotherm is determined by the Langmuir volume and Langmuir pressure at a given temperature. For any pressing factor, the amount of adsorbed gas can be determined. There is just a single error between the numerical and actual depiction of the adsorption/desorption measure. Hypothetically, as pressing factor patterns to boundlessness, gas-stockpiling limit will be limitlessly near Langmuir volume, yet in the genuine case, it will not arrive at the Langmuir volume hypothetically. In the genuine case, the adsorbed gas begins to be desorbed when pressing factor diminishes from some undeniable level to a point called "basic pressing factor". Once, the pressing factor dips under the basic pressing factor, and the desorption cycle will follow the Langmuir Model (UPDATE, MENDOZA, and SANCHEZ n.d.). One of the issues with gas desorption will be the amount of time it takes. Adsorbed gas atoms are believed to desorb from the network molecule surface as the pushing factor decreases. In any case, in any event, when the pressing factor condition permits gas desorption, the cycle of gas desorption happens for more broadened periods. The time stretch between when the pressing factor drops to the desorption level and when desorption happens is called desorption time.

4 Gas Adsorption/Desorption Processes During CO_2 and CH_4 Gas Injection

There are two ways to affix gas particles to rock surfaces: via van der Waals forces or by electron-sharing or movement bonds. A monolayer can be framed by chemisorption, while Physisorption can produce inclusions that are either monolayers or multilayers. Desorption, on the other hand, is the reversal of this process, in which the gas is released from the stone's surface. As the pressing factor grows, so does the amount of adsorbed gas, and vice versa (Eide et al. 2020; Eliebid et al. 2017a, b). At gas supply circumstances, CO_2 and CH_4 are both in their supercritical form. The primary function of CO_2 is at 310 C and 7.4 MPa in contrast to − 82 0 C and 4.6 MPa for CH_4 in the stage outline. CO_2 can take the place of CH_4 in favorable adsorption locations since CO_2's subatomic span is smaller than CH_4's (Du et al. 2019). Thermodynamic analysis demonstrates that their net warmth, which rises as fundamental pressing forces and basic temperatures in the gases increase, determines the sorption limit of the surface. Because of carbon dioxide's high compressibility, an electric field can distort the gas's circular symmetry. The polarizability of the atom is used to illustrate how simple it is to distort this scheme, which results in the particle establishing a second dipole. Atoms with minimal electron thickness tend to demonstrate strong collaboration between the orbitals, making it difficult to be enthralled by disturbances from external electric fields (Mabuza et al. 2020; Sakurovs et al. 2010).

4.1 Enhanced Gas Recovery from Shale Gas Formations

The pores of the network/break architecture will hold natural gas, which will fracture in shale formations in an unanticipated manner. Also, the kerogen (natural substance) and mineral synthesis of the shale affects the gas' accumulation (Eliebid et al. 2018). Shale development is depicted in terms of the total organic content (TOC) of the material. Immature shale with a high adsorption limit is characterized by a high TOC context (Takbiri-Borujeni et al. 2017). Porosity, thermal maturity, and the type of kerogen affect Methane sorption limit. In light of the low dispersion coefficients of carbon dioxide, a wide spectrum of kerogen exhibits greater adsorption behaviour toward CO_2 than CH_4 (Zhang et al. 2012). The tendency for gas adsorption to increase with increasing organic substance thermal maturity (Chalmers and Bustin 2008). In addition, a study of the shale's topography revealed that the illite material and TOC extended, resulting in an increase in the gas adsorption limit of the shale's micro pores and meso pores (Chi et al. 2019). Shale favorably adsorbs carbon dioxide to methane, which is useful in CO_2-EGR (Eliebid et al. 2017a, b; Rani et al. 2019). CO_2 and CH_4 in shale gas deposits are shown in Fig. 4. It is shown that increasing the CO_2 level increases the adsorption take-up in shale configurations, suggesting that CO_2 may desorb CH_4. Adsorption bend at 100 C and 4.5 MPa is largely due to the warm breakdown of natural materials and the more critical change in their crystallinity, which makes CO_2 and dirts preferable (Hui and Pan n.d.). The exothermic nature of adsorption has been explained by the negative estimations of adsorption heat. Adsorption of pure CO_2 or a mixture containing 90% CH_4 and 10% CO_2 is limited at low temperatures due to limited

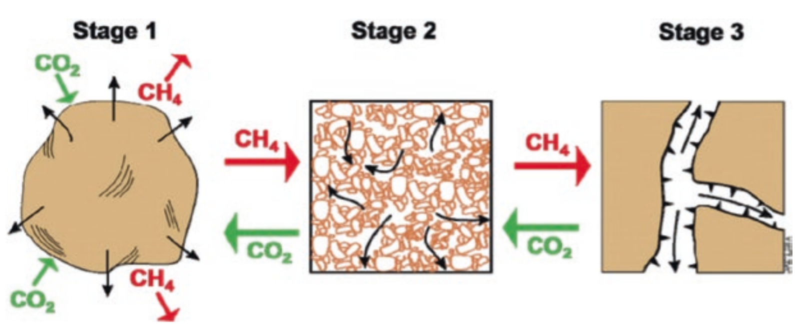

Fig. 4 Flow behavior of CO_2 and CH_4 at different flow stages in shale gas reservoirs (Godec et al. 2014)

surface access (50 C). While the unrestrained rate of adsorption slows down at high harmony temperatures (150 C) because the nuclear power exceeds the adsorption energy. The pore porosity of shale is influenced by the shale's long-term CO_2 exposure (Pan et al. 2018). After 30 days of exposing shale experiments in a reactor to supercritical CO_2 at 40 C and 16 MPa, it was discovered that the pore geometry and morphology changed from complicated to standard, with the greatest impact on microscopic pores (Zhang et al. 2016). CO_2's dissolving action and the subsequent growth set-off following adsorption may influence CO_2-EGR productivity and CO_2 sequestration in a positive or negative way (Sun et al. 2018; Wang and Marongiu-Porcu 2015). Miniature cross sections at 800 C and 20 MPa, confirmed by Pan et al. (2018), showed a decrease in typical pore size. Subcritical CO_2 (30 C and 5 MPa) has little effect on pore size transport. Because gas adsorption is so small (less than 10 nm), it impacts gas permeability through small pores on the surface of the shale (Sun et al. 2018; Wei et al. 2013). At high pressing factors, gas adsorption takes precedence over gas slippage; at lower pressing factors, the opposite is true. In pores larger than 50 nm, gas slippage and the Darcy stream predominate (Sheremetov et al. 2014). CH_4 desorption increases shale penetrability at high pressing factors, however at low pressures, there is no significant association between the typical pore pressing factor and porousness (Kim et al. 2017; Sheng 2017).

4.2 Continuous CO2 Injection Technique

Constant CO_2 injection involves injection and formation wells. Injection wells inject CO_2 into shale reservoirs to increase supply pressing factor, whereas formation wells deliver gas (Liu et al. 2013). Depending on the pressing factor slope, CO_2 penetrates the shale reservoir, dislodging CH_4 gas by adsorption and pressure (Song et al. 2019). Reservoir pressure slope, CO_2 infusion (pressing factor and stream rate), well dividing, shale network features, and designing plan (fracture flow tendency) promote continuous CO_2 injection (Schepers et al. 2009; Warren 1963). Schepers et al. (2009) used a double porosity, single penetrability model to consider the impacts of continuous CO_2 infusion on CH_4 recovery and CO_2 storage in a Devonian gas shale play. The double porosity model predicts a fractured reservoir to be made up of fractures and networks, with breaks providing flow channels and fractures acting as gas pathways (Karimi-Fard et al. 2004). Researchers studied 20 years of formation following the underlying recovery, which delivered for a long period, at 307.65 kPa reservoir pressure, 206.8 kPa formation pressure, and 303.15 K supply temperature. CH4 recovery increased by 7.3–26% when the well separation was between 146.6 and 196.6 m, and 60–100% of the injected CO_2 was recovered. CO_2 over CH_4 pressure gradient, and shale thickness cause this. Gas flows from shale to wellbore through fractures and desorption (Reeves and Pekot 2001). Shale reservoir thickness is a key factor in gas production and recovery. Despite positive discoveries, the double porosity-single permeability model has many limitations, such as an inability to accurately measure the flow of capacity between the fracture and the fracture (Chitsaz et al. 2015; Fathi and Akkutlu 2014; Jiang et al. 2014). Also, it overestimates the liquid transport rate (compared with the flow in real wellbores) because adsorbed CH_4 diffuses from the fracture into the fracture after desorption (Eshkalak et al. 2014a; Wu et al. 2019). Fick's first law doesn't accurately depict multicomponent gas stream elements (Bacon et al. 2015). Jiang et al. (2014) created a multi-continuum multi-segment model to explore CO_2 infusion in shale to improve CH_4 recovery and CO_2 stockpiling in shale gas sources. The model used multiple interacting connecting continua (MINC) and discrete fracture model (EDFM) to reconstruct liquid transfer between grid and distinctive fracture. After necessary recovery (led without CO_2 infusion), CO_2 was injected for a long time with a 12 MPa, 423 K, and maker supply (4 MPa). Depressurizing the supply and CO_2 dislodging CH_4 increases CH_4 recovery and CO_2 sequestration. Gas adsorption/desorption and fracture (normal and energised) affect well profitability. Lower reservoir pressure increased gas flow. Using this model and the double porosity-double penetrability model, analysing liquid stream constituents in water-powered fractures enhances shale gas recovery and capacity. Bacon et al. (2015) modelled the effects of continual CO_2 infusion in shale on CH_4 recovery and CO_2 storage. At 9 MPa and 320.5 K, CO_2 was infused at 10.95 MPa continuously for a long time in one of two flat water-driven cracked wells. CH_4 recovery improved by 10% compared to no CO_2 infusion, and 88% of infused CO_2 was sequestered. This was due to water-driven cracking therapy, CH_4 desorption by CO_2, and supply re-pressurization. Although, this model did not show the importance of gas stream constituents to gas creation and capacity in shale. The all-inclusive Langmuir isotherm model was used in this reenactment to examine gas adsorption despite its limitations. The Langmuir model assumes isotherm balance and does not accurately predict high-pressure gas adsorption (Lan et al. 2019).

4.3 CO2 Huff-n-Puff Technique

The huff and puff cycle can be described as the use of a single well, which functions as both an infusion and formation well. There are three major steps in this process: To begin gas production, a flat well is converted to a CO_2 injector for a period of time, after which the well is closed to allow the CO_2 gas to splash and then reopened to resume gas production (Eshkalak et al. 2014b). As a part of the episode n-puff cycle, a gas infusion was designed to retain supply pressures higher than the dew highlight condensate arrangement and re-disintegrate framed condensate to the gas stage. Well formation is reduced by the presence of framed gas condensate close to the wellbore. (1) CO_2 infusion pressure, which provides the critical power anticipated to uproot CH_4 from shale repositories (Kazemi and Takbiri-Borujeni 2016; Meng et al. 2018; Meng and Sheng 2016), encourages the CO_2 huff-n-puff cycle. It is important to know the rate of CO_2 infusion since it determines how quickly the total CO2 infused into the shale will progress over time (Mamora and Seo 2002). CO_2 infusion time is used to compare the duration of the CO_2 infusion to the total amount of CO_2 injected into the shale supply (a grouping) (Wu et al. 2015). Allowing CO_2 atoms to permeate the shale grid by convection and diffusion enables CH_4 particles to be enacted and dislodged (Jiang and Younis 2016; Louk et al. 2017). When it comes to assessing the effect of CO_2 injection and drenching time on the reservoir's pressure and gas formation, it is common practice to use a grouping shrewd approach, in which each infusion cycle is completed before the next one begins (Meng et al. 2017; Pranesh 2018).

4.4 Challenges of Enhanced Gas Recovery Techniques

Most CO_2 infusion procedures center on assessing the CH_4 recuperating and CO_2 sequestration capability of the shale supplies. Nevertheless, these methods' achievability in the field-scale preliminary is very confounded because of the intricate pore structures in shale and the ultralow penetrability. Iddphonce et al. (2020) identified some issues that are important for the prospect of CO_2 injection techniques as summarized below.

- Future exploration should include shale supply heterogeneity, especially CO_2 and CH_4 adsorption and multicomponent gas stream constituents. Transport and interconnection of shale gas components are critical for investigating adsorption and stream characteristics.
- Concern has been expressed in several studies that CO_2 administered during the episode n-puff cycle will be repeated with gas. To better understand how the CO_2–CH_4 adsorption system and the fracture characteristics

of shale are affected by the infusion sum, splashing time, and formation time, we propose additional research.

- Most models used to examine the stream elements of gases are appropriate for all around associated fracture, accept shale development as homogenous, and cannot demonstrate liquid stream in animated breaks. Future reenactment models ought to likewise consider this since liquid stream elements are fundamental for anticipating gas formation and capacity in shale.
- Current examinations have failed to assess the adjustments in reservoir temperature initiated by CO2 infusion; thus, we suggest considering heat move impacts of the stream elements of gases.
- The limits in existing lab offices (particularly to reproduce genuine shale reservoir conditions) impede trial-based ways to deal with assess CO2 infusion methods, recommending field tests as a possibility for future examinations.
- Future investigations ought to anticipate the commitment of gases put away as free stage, adsorbed stage, and broke up stage to both recuperated CH4 and sequestered CO2.

4.5 Conclusion

Enhanced gas recovery (EGR) and subsurface geological sequestration of greenhouse gases have been discussed in detail in this chapter. In shale reservoir, huff-n-puff and gas flooding have been presented as possible techniques. Huff-n-Puff method of gas injection is more efficient than gas flooding because of the faster response time and greater pressure differential between reservoir and wellbore pressures of huff-n-puff injection. Adding carbon dioxide to the mix results in a significant increase in gas production. Finally, we looked at the difficulties that can arise when putting gas injection procedures into practice.

No matter how much study has been done, our understanding of gas injection EOR/EGR procedures for such resources remains restricted despite all of the work done. There is still a divide between the oil and gas companies and the environmental stakeholders when it comes to CO_2 sequestration and greenhouse gas reduction. To ensure that our energy needs are met while also conserving the environment, we must find a way to fill this gap in our energy supply. Enhanced recovery technologies for shale gas must be developed in order to reduce environmental impact.

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Geopolitics of Shale Gas

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Abstract

This chapter will provide an acknowledgement of processes, concern regarding them, and geopolitics behind the exploitation of shale gas across the borders of countries to continents. Utilization of natural gases is shifting towards unconventional techniques from conventional. Shale gas reserves are nonuniformly distributed across the globe. This arises the geopolitical competitiveness to possess and exploit shale gas resources beneath their territory. This chapter highlights the growth of shale gas exploration and exploitation in different regions of the world, impact of geopolitics on shale gas exploration, consumption and prices. Exchange of technologies (fracking) to other nations for accessing their shale gas reserves will be further discussed. The chapter also includes possible threats to shale ecosystem, impact of ongoing conflicts and future prospects of shale gas on global politics. The chapter concerns about overview and dilemma of the proceeding towards unconventional gas resources as there are protest arising day to day.

Keywords

Geopolitics · Shale gas · Exploitation · Future prospect

1 Introduction

In the twenty-first century, where natural resources are the basic accounts for the richdom of any region. Understanding the geographical status of the world in respect of politics and international relations is known as Geopolitics. Shale is the reservoir rock for shale gas, extraction of this economically important natural gas is done by a complex process of fracking.[1] There are always been demand, disputes and insurgence over natural resources; these reserves determine the value of their holders, as there is always a rivalry for its count.

In this chapter, we will discuss and determines the aspects of geopolitics regarding the exercises of shale gas reserves and production. Worldwide reserves, exploitation and transportation mediums will be discussed shortly;

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[1] Hydraulic fracking to dig boreholes.

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it will allow us to attain the significance and economic importance of shale gas (Shiqian 2017). The commercialisation of shale gas is a major part of geological exercises in the recent world, though a brief report on the commencement of its uses and trade will be delineated in the chapter respectively. In recent times various military conflicts and ongoing wars have impacted the supply and demand for the natural gas and shale gas in particular, we have briefly analyzed the effect of the geopolitical conflicts on the economics and development of shale gas exploitation.

2 Exploration and Expansion of Shale Gas

Hydraulic fracturing is the technique operated for the exploration of shale gas, as it is trapped in shale, and natural gas[2] produced with help of this technique is referred to as 'unconventional[3]'. The hydraulic fracking technique uses water at high pressure to generate narrow fractures. Tough in terms of geopolitics, the hydraulic fracking market has lonely reported a turnover of $48.34 billion; where applications of shale gas significantly contributed (Research and Markets 2021).

2.1 Worldwide Resources

Russia accounts for containing the world's largest natural gas reserves which are about 1.32 quadrillion cubic feet which are approximately 20% of worldwide reserves of natural gas. However, Unites States and China hold up the highest production of shale gas in the world. China (14.3%) in Asia and US, Canada, and Mexico in North America (23%) are the largest technically recoverable resources found in the world (Fig. 1).

Besides the majorly distributed reserves, technically recoverable reserves are also found in the region of Europe (significantly in SE Europe, Ukraine, Poland, France, UK, Denmark, and the Netherland). The rest of the significant countries in terms of long-established hydrocarbon exportation like Algeria, Saudi Arabia, Russia, Libya and Egypt are supposed to have 9.1–1.3% of total abundance. Several nations are concerned about replacing crude oil consumption in power plants with shale gas, for accomplishing the needs of the domestic power market. From a geopolitical perspective, exporting crude oil in the international market develops more revenue than the exportation of natural gas; shifting towards shale gas consumption for domestic purposes will impact the inflation and expenses of domestic needs.

2.2 Shale Gas Exploitation

There was no particular significance of shale gas exploitation and utilisation before a decade, but it is now recognised as a more efficient driving force in universal gas output. Within the last decade, data from global outputs of energy utilisation and greenhouse index in the USA reflect a path to energy independence; with the help of hydrocarbon extraction through shale. Nevertheless, production of shale gas and oil has been sustainably developed with implications of improved drilling machinery and well productivity in respect of altering prices of oil and rig counts. This operation is certainly encouraged by the outcomes observed by shifting shale from coal in the US; according to research conducted from 2007 to 2012, a drop of about 12% in greenhouse gas emissions is reported. Analysis of the issues and complexity of exploitation of shale gas is typically constrained by numerous problems which are horizontal good fracturing, improper resources, and endowment. In particular, non-marine shale deposits and complicated tectonics are the major issues in the exploitation of shale gas.

2.2.1 Asia

China is the lead producer of shale gas in Asia and the world as well, by 2013 shale gas production in China was negligible in terms of overall

[2] Referring methane and ethane processed out from geological reservoirs.

[3] Place of origin and preservation are same.

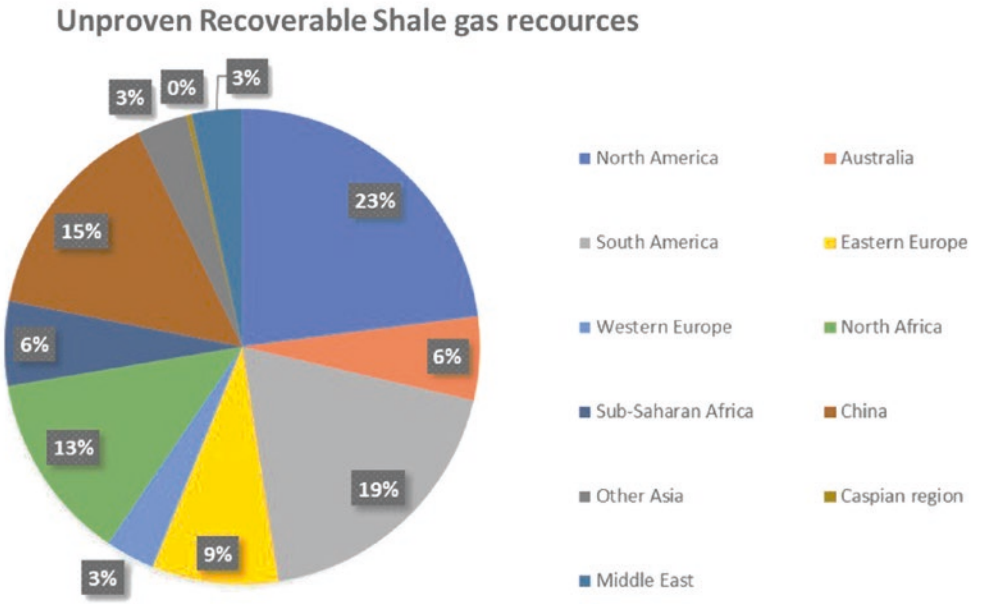

Fig. 1 Geographical distribution of shale gas reserves

natural gas production in China. Here the concern of increasing their production arises by 2015, which was assumed to be 30 billion cubic meters (BCM); yearly goals were established in such proportions of forthcoming production which will be equivalent to half of the gas consumption by entire China in 2008. Though it cannot be done with the specific intervention of advanced technology; in 2009, Barack Obama agreed to plead with China for sharing US gas-shale technology, and either in terms of promoting US investment in the development of Chinese shale gas project. Although China faced numerous more difficulties in attainment of their futuristic approach of increasing shale gas development like the complexity of geology and terrain, lack of water resources and undeveloped or limited expertise (Shiqian 2017). Hereby, the government of China has set aggressive goals of achieving 60 bcm per year by 2020. For this attainment, the Chinese government leased their 20 blocks of shale gas to 18 companies, a similar auction for leasing their gas blocks also occurred later. Since China is highly dependent on the South China sea route to procure its energy needs, it leaves China extremely vulnerable to any conflict in this region. Any potential conflict in the south China sea region can result in an effective blockade of the hydrocarbon resources of the country. Hence the leadership of the country has set highly ambitious targets for shale gas production including 65–100 Billion Cubic Meters in 2020. But due to practical reasons like high cost, lack of investments and lack of technological set-up for optimal exploitation of reserves, Chinese producers continuously struggle to meet these targets with 2020 production being 20 bcm (Wei et al. 2022).

2.2.2 South Asia

India approximately contains 96 trillion cubic meters of shale gas reserves. Government policies for exploitation significantly alter the outcomes and production, whereas in India shale gas complications are regulated by Indian policies because government-issued leases in favour of conventional exploration (petroleum) excluding unconventional sources like shale gas. Reliance industries limited and RNRL and others effectively contribute to the battle of prospering country's economy and growth by accessing unconventional resources of energy also.

Policies have been changed under the premises of licencing policy and hydrocarbon exploration which will permit the intrusion of a private organisation to attain a uniform license; this will allow them to explore and exploit conventional as well as unconventional natural resources (oil and gas). The concern of shale gas exploitation was taken forward and a delegation was scheduled for the meeting between officials of the Indian oil ministry, their director-general of hydrocarbons and USGS.[4] In 2010 meeting was held in Washington, where officials discussed the exploitation and identification of natural resources of shale gas in India. Basins of primary attention identified by the GSI[5] are the following: Gujarat's Cambay Basin, the Gondwana Basin of Central India, and the Assam-Arakan Basin situated in northeast India. A supportive statement was then given by US President Obama while a visit to India in 2010; which stated the cooperation in pursuit of pure energy and the mission of zero-emission, along with it opening of the research centre for clean energy in India and perusing combined research in biofuels, shale gas and solar was the most efficient affirmation (Nakano 2012).

Pakistan is the 19th major country for acquiring technically recoverable reserves of shale gas, it has an estimated reserve of 105 trillion cubic meters. Nonetheless, the Islamic Republic of Pakistan consumes 100% of the natural gas whatever it exploits and produces; it delivers no contributions to the export of natural gases in global trade and there may be a chance of growth by shale gas in future.

2.2.3 The Americas

On the land of North and south America's continent, there are four lead producers of shale gas which are Argentina, Canada, Mexico and the United States. In the list above excluding Argentina, the rest of the three are in North America making it the second heaviest contributor of technically recoverable resources of shale gas in the world. Hydraulic fracturing and horizontal drilling are the two newly introduced technologies for the exploitation of shale gas reservoirs in the United States and their co-operations with other countries is successively delivering the contribution (Kobek et al. 2015). In 2013, EIA reported an estimated reserve of 802 trillion cubic feet in Argentina; making it the third largest reservoir of recoverable shale gas. 'Vaca Muerte formations are the major contributor of tight oil as well as gas in Argentina.

This was a topic of limited attention by 1800 when exploitation of natural gas was addressed in shale formations, located in the Appalachian Mountains (United States). Norman wells of Northwest Territories of Canada, second white speckled in southeast Alberta, Antrim shale in Michigan basin were later introduced by 1940s. These formations certainly assisted in economic recovery, as their vertical wells were producing at minimum rates for a long duration.

3 Commercialisation of Shale Gas and Geopolitics

With the increase in demand for zero combustion reliability, several nations are on the path of shifting their energy consumption towards natural gases. There are possible figures discussed soon, which will determine the forthcoming possibilities of natural gas production in the next two to four decades. One of the significant events forms 2000 is the trading of global energy; particularly reflecting the stellar expansion of production of shale gas in the US. It has been done by the advancement of technology used for exploitation of the respective resource, management issues of looking over the needs of gas value chain along with the expansion of this business. For this instance, "ETRM (Energy Trading and Risk Management)" efficiently works upon the situation by using an integrated system. Allowing data exchanges among the global traders, artificial surveillance of supply and trading of fuels, gases, refined products and others.

An alteration in the global market can be seen along with the expansion of shale gas

[4] United States Geological Survey.

[5] Geological Survey of India.

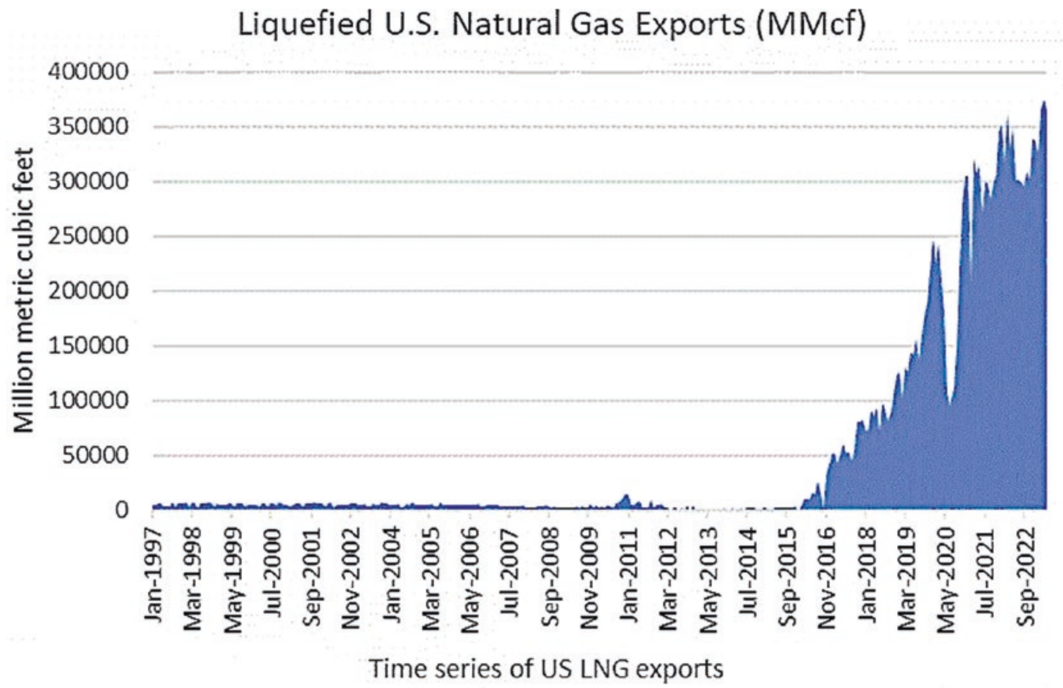

Fig. 2 L.N.G exports from United States over last two decades

production; where the US promotes itself as being the largest producer of natural resources, specifically oil and gas (EIA 2021). Shale gas exploration has begun in 1949 when the government of the USA 1975 enacted limitations on the export of crude oil. It was done in favour of American consumers to provide aid from the price volatility in the global market. Today, all of the bans on exportin have been lifted; just because of the advancement in technology which helped in the blooming of America's energy industry. However, the laws governing America's oil exchange were outdated and the lifting of the federal laws assisted in leading the production resulting in the surpassing of Russia and Saudi Arabia. Free trade investments, economic growth and relevant policies like introducing jobs lessen their need for imports from the middle east. As there we are acknowledged how the foreign policy of the United States is affected by the export of crude oil; it also alleviates the needs of imports for US allies by the export of surplus crude oil from the end of the United States. This particular trade strengthens and influences foreign policy as well as the trading position worldwide for America (Fig. 2).

Despite the fact discussed above, rising shale gas production with relevant political disputes has certainly contributed to escalating 'global gas flaring[6]'. Data observed from the satellite surveillance has shown an increment of 3% global gas flaring in 2018, this estimate is as approximate in comparison to the consumption by south and central America.

Similarly in South Africa, the Karoo region which is sensitive to shale gas development has gathered the attention of various energy companies, organisations, governments and the public typically. Even though, the government of South Africa is waiting with a bated heart to resuscitate economic growth and also in improving energy security to deal with the energy supply crisis which is a special concern and drawback in this modern age of technology; why is South Africa in dark? Questions alike are continuously

[6] Ignition of natural gases linked with oil extraction, occur due to technical or economic constraints.

arising in 2022 still. South Africa has reported a recoverable natural gas estimate of 390 trillion cubic feet which can be exploited from shale in the Karoo basin. While the respective government tries to step forward for the exploration, the dominant coal industry and alike alternatives such as renewable sources and nuclear energy intrude the attention. This increasing concern is related to the economic viability of the shale gas deposits of South Africa.

4 Shale Gas Industry and Sensitive Conflicts

Exploration and exploitation of oil and gas from unconventional techniques like fracking, etc. have been raised once to fulfil the domestic energy supplies and security. It certainly lessens the reliability of other states and their allies over Russia and 'OPEC'; afterwards the introduction of the Russia-Ukraine war and its consequences, definitely supported the above statement. Despite the western leaning and their supportive statement, there are major environmental issues like contamination of water and land rights were lifted above (Bayley 2015). Nevertheless, everyone knows that the world's richest continent (in terms of natural resources) is also the world's poorest. Unquestionably it is a resource abundant as gold, uranium, oil, copper, natural gas and many more are heavily occupied in the African region.

4.1 Russo-Ukrainian Conflict

In February of 2022 Russian army crossed the international border into Ukrainian territory with aim of demilitarizing and changing the regime, this conflict resulted in a full scale war. What followed was the internationalisation of the conflict as the European Union and western countries imposed severe sanctions on Russian Federation targeted to cripple the Russian economy while providing tactical support to Ukraine. As the conflict rolled out European Union which depends on Russian gas for 40% of its natural gas consumption, stated to draw plans to reduce its gas purchase from Russia and started looking for other sources of Gas (EIA 2021).

EU's shifting away from natural gas means securing demand from other sources the main source which has the potential to replace Russian gas is abundant shale gas production in North America, which can be brought to Europe as LNG. European governments started to upgrade their LNG infrastructure to receive more gas from the USA. Meanwhile, Russian gas supplies to the European bloc were reduced continuously citing technical reasons. If it was not for the American shale revolution Europe could not think about moving away from Russian natural gas. Overall, the increased European gas demand will promote American shale producers to increase their production. Hence in a way, shale gas proved to be the backbone of the western bloc, backing the gas-dependent economies of Western Europe (Shiryaevskaya 2022).

The conflict in Ukraine had a contrasting impact on production in the world's two major shale producers. China world's second-largest shale gas producer after the USA will experience a detrimental effect of the conflict (EIA 2016). As Russia is losing its European markets it is looking east, and aggressively marketing its gas with huge discounts to LNG from the Middle East or USA. With the infrastructure right in place with the construction of the 61 billion cubic meter per annum capacity "Power of Siberia" pipeline, Russia is providing the Chinese market with cheap gas rendering the high-cost Chinese shale gas producers uncompetitive (JENNIFER SOR 2022). With Chinese shale producers making fewer profits and a lack of investments in the sector due to larger financial situations, the industry is set to lose its initial progress in forthcoming consequences.

Russia world's second-largest gas producer and largest exporter of conventional natural gas. It has an immense amount of technically recoverable shale gas around 267 trillion cubic meters and has the world's single largest hydrocarbon-rich shale basin 'The Bazhenov formation' with an estimated initial gas in place of 1920 billion cubic meters. Still, it is not a major producer of shale gas due to two main reasons, first the availability of lower extraction cost dry gas and associated gas wells. Second is the lack of technical capabilities to exploit shale reservoirs. Russian exploration and production giants are largely dependent on western investments and know how to extract shale gas resources (EIA 2021). Due to this conflict, on the one hand, Russian forces have taken control of much of Ukraine's shale basins in the east of the country thereby adding up reserves of the country by an approximate 8976 billion Cubic meters, on another hand the stringent western sanctions on technology exchange to Russia and voluntary exit of major oil field service companies like Schlumberger, Halliburton etc. will make it difficult for Russian producers to extract these reserves.

Meanwhile, Algeria is in proximity to Europe which is the most competitive natural gas market. With natural gas prices record high after the conflict, the Algerian National oil company The Sonatrach is seeking to increase its production to satisfy the demand. Development of shale gas exploitation is one of the key priorities of the company with many trial projects ongoing to test the potential of exploiting shale reserves. Already Algerian NOC is developing Algeria to Spain Pipeline Medgaz's capacity by 25% to 10 bcm per annum and increasing LNG export infrastructure.

Europe (including the United Kingdom) even has one of the largest shale gas reserves in the world. France (4.2 tcm), Poland (3.9 tcm), Romania (1.4 tcm), Denmark (0.90 tcm) and others in total Europe have a recoverable reserve of about 13.3 trillion cubic meters. But so far it doesn't produce any shale gas due to its very strict policies regulating the exploitation of shale resources. Fracking has been systematically demonized by the green parties of Europe, creating a situation where Europe having investments and technology to produce shale gas did not allow its production.

As the Russo–Ukrainian conflict intensifies there are heightened fears of a complete gas supply halt from Russia, insecure about their energy needs European nations are reconsidering their approach to shale resources and started to look at them as an alternative to Russian gas. In this chain of events UK leading the bandwagon has already reconciled its fracking policy and is starting to issue new licences for exploration as early as October 2022. Meanwhile, Europe is still divided in its stance on shale resources with a study showing a higher proportion of 73% of the German parliamentarians voted against the exploitation of share reserves while 27% considered it as a short-term solution for the energy crisis.

4.2 The Middle East—Strait of Hormuz

The Persian Gulf is the source of 21% of hydrocarbon exports in the world. Therefore, the stability of this region plays a crucial role in the price dynamics of hydrocarbon fuels. As the region is home to groups of populations with diverse geopolitical interests and has seen multiple wars in the past few decades. Also due to huge resources of hydrocarbons in the regional geopolitical events like a potential Iran nuclear deal can open the tap of resources in the country which can result in the collapse of natural gas prices making investments in the capital-intensive shale projects unpreferred by the investors and hence reducing the potential of shale gas exploitation worldwide (EIA 2016).

Will shale gas be an important objective of geopolitics in the times to come?

Already North American shale gas has emerged as the saviour of its EU and NATO allies from energy starvation after a reduction in gas from the Russian side and in event of a threat of a complete halt of gas. North American shale gas strengthens the US and NATO alliance and supports the economies of NATO member states as it proves to be an efficient energy resource for them. American shale revolution reduced American dependency on hydrocarbon imports mainly from the dynamic middle east and other producers. It reduced the power of the oil cartel OPEC but the change in administration in capitol hill Washington, and the new anti-fracking stance of new administration is hurting America's newly found and short-lived energy independence and once again bringing the future of the western bloc in danger and losing its control in the hands of conventional resource-rich nations mainly part of OPEC plus.

China will try to replicate American success with shale gas and create its version of the shale revolution. With some challenges ahead like access to cheaper imported gas and higher cost of production. But if China succeeds to develop and exploit its mammoth shale gas reserves it can strengthen its energy position by securing its internal northern and central parts and taking more risks in the southern part including a more aggressive approach in the South China sea. This can create an aggressive power struggle or a full-blown conflict in the South China sea region mainly with countries like Taiwan and Vietnam which have protested China's activities in the region. Therefore, it will be of global interest to watch and analyse China's shale growth story.

5 Conclusion

Though it can be concluded that shale gas plays an important role in attaining the aspects of zero-emission and lowering the impacts of greenhouse effects. Exploration and exploitation need a brief report on the accessible resources of shale gas which must be technically recoverable, United States has certainly delivered their technology of hydraulic fracking and horizontal drilling to the demand of particular nations. This can be a beginning of an era of joint operations which are efficient in delivering more significant results than any country holding resources but not technology to access it. In the chapter, we have discussed the availability of resources worldwide along the continents and determined them for their efforts of shifting fuel consumption for domestic and commercial purpose.

'We are not wild west' alike phrases were seen warming up the crowd in Romania, concerning ecological risks involved in shale gas industry. Nations like France, Britain, Lithuania, Algeria, are currently seen active to the regarding protests. These campaigns are grassroots direct actions opposing unconventional gas reserves. Howsoever hinging on the requirement of development will not be affected by these protests of regionally limited people. 'The world has enough for everyone's need, but not for everyone's greed'—M. K. Gandhi.

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Shale Gas Development in India: Challenges, Legal Regulations and Way Forward

Ashok Kumar Tyagi and Gagandeep Kaur

Abstract

The remarkable surge in shale gas production in the US has sparked global interest in unconventional gas sources. Shale gas, which accounted for a mere fraction of production in the US in 2000, has rapidly grown to comprise 23% of total production by 2010, projected to reach nearly half by 2035. This trend has spurred India's own exploration of unconventional resources, spurred by policy reforms like the Hydrocarbon Exploration and Licensing Policy (HELP) and Open Acreage Licensing Program (OLAP) from 2015 to 18. India's growing natural gas consumption and diminishing conventional reservoirs have urged a shift toward unconventional options. The appeal of natural gas, being an environmentally cleaner energy source, is rising significantly. As natural gas imports increase due to economic growth, it's crucial for India to focus on developing alternate resources like shale gas and oil. The recent surge in hydrocarbon prices has highlighted the need to strengthen India's economic resilience. Potential shale gas reserves exist in sedimentary basins across Gujarat, K-G, Cauvery, Assam, and Rajasthan. To tap into this potential, India must establish an industry ecosystem aligned with advanced drilling and hydrofracking techniques from the US. This includes horizontal drilling, hydrofracturing, and advanced seismic imaging that have propelled the shale gas boom in the US. This chapter outlines India's challenges while drawing insights from the unconventional industry in the US, Canada, and China. It emphasizes building infrastructure for shale gas, addressing freshwater availability, horizontal drilling techniques, hydrofracking impacts, and pollution control. Recycling of water and chemicals, as well as efficient gas transportation, are examined. Additionally, the paper delves into policy, legal status, and reforms within India's unconventional sector. As the world shifts towards cleaner energy, understanding the challenges and regulations surrounding shale gas development is crucial for India's energy security and economic growth.

Keywords

Unconventional gas · Hydro fracturing · Microseisms · Aquifer Pollution · Horizontal drilling · Shale gas development · Shale gas boom · Legislation and policy

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1 Introduction

Natural gas production from highly organic shale rocks has become the leading and fastest-growing source of natural Gas in the United States. It can potentially become a global alternative gas source in Canada, China, Australia, South America and even India (Si et al. 2023). Learning from secondary and tertiary production innovations and technologies from matured conventional giant fields, the energy companies in USA up-scaled the two predominant technologies, namely hydraulic fracturing and horizontal slim hole drilling in a big way in Shale gas and tight gas reservoirs (Hübner et al. 2013). As a result, from virtually nil production in the year 2000 in US, shale gas production has reached a level of 23% in 2010 and is expected to comprise nearly half of the total natural gas supply in 2035 (Dudley 2018). Indian shale gas industry needs to quickly develop and evolve similarly in laying down the entire unconventional expertise, Technology and infrastructure footprints. The prominent shale gas resource areas are Krishna-Godavari, Western Onshore (Cambay-Mehsana-Ankleswar arc), Assam-Arakan, Rajasthan, and many others sedimentary basins. Preliminary estimates from different E&P agencies (EIA and USGS) suggest in-place shale gas resources to 290 TCF with technically recoverable reserves of 93 TCF in Cambay, Krishna-Godavari, Cauvery & Damodar Valley Basins of India. The rapid rise in natural gas production from shale in the US has led to renewed interest in developing unconventional Shale Gas Resources in India. From virtually nil production in the year 2000 in the US, shale gas production has reached a level of 23% in 2010 and is expected to comprise nearly half of total natural gas supply by 2035. Shale Gas production has reached a level of 80% of Total Natural Gas Produced in the year 2022 (EIA March 23). From a meagre production in 1999 it has reached a level of 26.91 TCF in the year 2022 and is likely reach to 35 tcf by the year 2050 (Alzahrani May 22, 2023).

2 Indian Natural Gas Demand and Infrastructure Scenario

India is amongst the top five energy consumers in the world, and the energy consumption growth is projected to be around 4.2% per year. The consumption growth is expected to be the fastest amongst the growing economies. During this period, India's increased domestic energy production is expected to fall short, and India's Gas bearing shale resources could provide the required thrust. Gas is a clean energy fuel, and keeping pace with the global trend in India has been increasing at a scorching rate, primarily driven by domestic cooking consumption, power, chemical, steel, and automobile sectors (Bhat 2019). Driven by the global clean energy focus, India is also gradually replacing its coal and oil based industries with natural gas/LNG. However, the power and fertilizer sectors remain the two most significant contributors to demand and continue to account for more than 55% of gas consumption. India is the fourth largest energy consumer, accounting for about 4% of world consumption. It is ranked as the sixth largest LNG importer, importing Gas in a different form (British Petroleum Annual Report and Form 2020). Against the world's natural gas consumption growth of above 2.75% in the past decade, India's growth trajectory increased to around 9%. The gas requirement in different forms has increased 3–fourfold. It is expected to hike further by three-fold in the next two decades as per Petroleum & Natural Gas Regulatory Board's (PNGRB) prognostication.

India's future gas consumption demand will likely rise at a CAGR of 7% by 2029–30. The Power sector consumed 38% of the total consumption, and the fertilizer sector accounted for 26% (Annual Report 2014–15, Petroleum & Natural Gas Regulatory Board). The future natural gas supply depends mainly on domestic gas production and increased LNG imports. Surprisingly, domestic production is going way down than earlier projections, possibly due to a steady reduction in gas output from the MH offshore field. The holding capacity of RLNG terminals is expected to increase from 17.3 MMTPA in 2012–13 to 83 MMTPA in 2029–30 in India, assuming all the existing and planned terminals in India would be operational (Annual Report 2013–14, Petroleum & Natural Gas Regulatory Board). The significant imbalance between Natural Gas demand and supply scenario has energized India to develop unconventional resources like Shale gas and Tight Gas reservoirs on the fast track. However, shale gas E&P has failed to catch up to the desired pace so far primarily due to a lack of unconventional domestic Infrastructure, freshwater resources, and a shortfall in India's technology and services ecosystem of the desired scale. Indian upstream Regulator also needs to provide much more fiscal concessions and policy waivers for the Unconventional Sector to grow profitably and thus facilitate the development of the global shale gas industry and experts in India at a much faster pace.

3 Shale Gas Resources and Reservoirs in India

Indian sedimentary basins have sufficient proven reserves in both Conventional and Unconventional reservoirs (Sain et al. 2014). The conventional reservoirs are dominated mainly by acceptable to coarse-grained Sandstone, Silt stones and limestones of diverse types and combinations having good porosity and permeability, resulting in self-induced pressure regimes in reservoir plays Palaeozoic, Mesozoic and Cenozoic ages. At the same time, the Unconventional shale gas reservoirs have very poor porosity and permeability parameters and need many cycles of massive Hydrofracturing operations to improve the transmissibility of trapped Gas in shale reservoirs to move to the surface. The Source Rock behaves as Reservoir Rocks in most prospect plays. With the US's tremendous R&D efforts, especially in Drilling, Hydro fracturing and Micro seismic imaging innovations, coupled with Government all round Policy and regulatory Support Shale Gas has emerged as one of the most prolific gas resources/reservoirs across the globe (Apostolatos 2014). The Natural Gas produced from Source shale with associated silty fine sands and organic matrix is a fine-grained impervious Sedimentary Reservoir, and Gas is self-sourced. Some Gas in the sorbed state in Rich Organic Fractions of Source Rock ("Basics of Shale Gas"). Preliminary estimates from different E&P agencies (EIA & USGS) suggest in-place shale gas resources to 290 TCF with technically recoverable reserves of 93 TCF in Cambay, Krishna-Godavari, Cauvery & Damodar Valley Basins of India. Central Mine Planning and Design Institute estimated 45 TCF of Gas in six basins: Jharia, Bokaro, North Karanpura, South Karanpura, Raniganj, and Sohagpur. Enthused by such reserves estimates, the Indian Regulator, since 2009, has initiated detailed exploratory plans with Indian O&G majors like ONGC, Reliance & OIL. However, significant issues include Freshwater requirements in hydro frac, Horizontal drilling, Hydro Frac infrastructure ecosystem and drilling and Frack wastewater recycling and disposal.

4 The USA Shale Gas Efforts, Challenges, and Subsequent Boom

Shale gas is being produced in smaller volumes since more than 100 years in United States from Natural Fractures in shale rocks. However, the real thrust came with the advent of massive fracturing technologies, horizontal/multilateral drilling, micro seismic and waste disposal technologies in an integrated environment. The concept of joint exploration and development by integrating research methodologies and operating techniques for various oil and gas resources to simultaneously achieve analysis, construction, gathering and exploitation of multiple hydrocarbon sources is now being bought globally (Zheng et al. 2017). These technologies were initially developed to enhance production rates in conventional O&G fields. They were upscaled later for fracturing the Shale

Gas reservoirs to create the mobility of Gas on the surface through the artificial fractures and voids. The realization and pressure of providing clean energy to the industries and moving away from Coal and oil-based energy systems to Gas based systems raised the demand of Gas in US manifold, and thus came the idea of putting in massive Hydro fracturing and horizontal drilling innovations in huge unconventional shale gas reservoirs. Shales rocks have very poor permeability and porosity and require Massive Hydro fracturing Jobs interventions to access the trapped Gas on the surface. With the focussed R&D and technology integration efforts of US coupled with the Government's all round Policy and regulatory Support and infrastructural commitments, shale Gas has initially emerged as the most prolific gas resource in US. With the shale gas boom in the US, the country moved from net gas importer to exporter in 2011.

It is remarkable to find the horizontal wells with lateral lengths up to 4000 mts within shales to create extensive borehole surface area in shales. The Gas is produced from kerogen-rich black shales by inducing massive fractures by fresh water from multilevel completions. Obtaining Production from Rocks with Nano Darcy Permeability has been a sheer technological excellence worth emulating by India and other shale gas-rich nations. Pressures are low but the length of the production period compensates the volumes produced. Shale gas tends to cost more than Gas from conventional wells, but the low risk and longitivity of shale gas wells often offsets this. Shale Gas/Tight Gas/CBM are being commercially exploited In US/Canada/Australia/China. Though USA is leader with a significant margin. US had zero productivity of shale gas in the early 2000s, and presently, the growth of its shale gas industry is expected to be able to provide half of the total energy production in the US by 2035 (Jain et al. 2016). Global High Oil Prices trend also helped US investments in shale gas industry development. However, the key was Technology Integrations combined with the US's Sound Fiscal and Environment Policies, along with government ownership and support on environmental policies. Fear of Fresh Water Aquifer Contamination while drilling and societal concerns on waste disposal (drilling/frac chemicals etc.) were effectively and timely addressed through Government's tremendous support. Plenty of Barren Land availability in shale gas-rich basins was of great help, and government support in the handing over process from landowners in all the basins was commendable (Si et al. 2023). The US Govt. signed a MoU with India's Ministry of Petroleum and Natural Gas (MoPNG) to support India's effort to develop its shale gas reserves on Dec. 6, 2010. Under this MoU, the DOS/US agreed to cooperate with MoPNG in shale gas resource assessment, technical studies, regulatory framework consultations, training, and investment promotion through exchanging experiences and best practices and through study tours.

5 Indian Shale Gas Industry Challenges

India's gas consumption is rising astronomically to meet domestic/automotive/power/fertilizer sector demand. Power and Fertilizer sector remains the two most significant contributors to natural gas demand in India and continues to account for more than 55% (Bhat 2019).

India could not take off so far due lack of desired interest amongst Indian Oil Companies and MNC's, lack of robust road infrastructure requirements, the shortfall in holistic drilling and fracture technology ecosystem etc. The problem is further complicated with the tremendous freshwater requirements in drilling and Hydro fracturing the shale gas wells. The good density is also kept high in order to keep gas volumes high and have the industry commercially viable. Many of the prolific Gas producing basins like Ahmedabad—Mehsana-Ankleswar basin are densely populated and land acquisition is a significant issue owing to the lack of barren land apart from freshwater concerns. Some R&D exploratory wells drilled by ONGC in Damodar Valley, Cambay basin and partly K-G basin since 2010 have not yielded significant development leads. The Indian Government permitted shale gas E&P in on-land areas to state-run Oil and Natural Gas Corp (ONGC) in 50 basins and Oil India Ltd (OIL) in 6 basins in 2013 on a nomination basis (British Petroleum Annual Report and Form 2020). In Phase II and III, ONGC was explored in 75 and 50 blocks, respectively. However, due to logistic constraints, ONGC Could only drill 20 assessment wells for shale. Fewer Shale gas wells have been completed in the last 10 years. Screening and assessment of exploration targets has not been entirely conclusive. As a result, the critical reservoir properties like Gas in place reserves; matrix permeability and geochemical details at the reservoir level; determining intervals for horizontal drilling plans and subsequent fracking at the reservoir level; Predicting production rates/decline rates; determining drainage areas (spacing units) in thick intervals of shale have to be ascertained at basin level for developing the production profiles. Because fewer exploratory wells are drilled, the Gas producers have less confidence in their Original Gas in Place calculations (Mendhe 2014).

6 Regulatory, Environmental and Societal Issues Impacting Shale Gas Development

Thus, the Indian shale gas Industry has been sluggish, and Government realized its immense gas production potential only a few years back. In the regulatory framework, unconventional/shale gas licensing policies are relatively nascent and must be more proactive (Si et al. 2023). The Government's Regulator's and upstream Regulator's commitment, ownership, and facilitation in terms of land acquisition, freshwater availability, road infrastructure, creation/facilitation of unconventional technology hub/ecosystem, and fiscal benefits/reforms ("Golden Rules for Golden Age of Gas"). The most critical issues required to be undertaken through Govt/Regulatory support include (Mendhe 2014)

Land Acquisition

The major Shale Gas Resources are hinging around Cambay—Mehsana Basin, Krishna—Godavari—Cauvery basin, Damodar Valley, Upper Assam Basin, and Rajasthan Basin as per the limited data. Acquiring land in these densely populated states is a sensitive issue with political ramifications. Govt must convince the landowners and farmers about the importance of shale Gas development initiatives and monitor until last through sound policy framework. In the US, underground resources are owned by landowners who often provide access to exploration and production for signing bonuses and royalties. In India, while India could benefit from extended cooperation with the US on shale gas exploration in the future, addressing 'above the ground' challenges, particularly concerning water and land, should be prioritized through cooperative federalism (Si et al. 2023).

Fresh Water Requirement in Drilling and Hydrofracturing

Shale gas drilling and formation evaluation/development requires around 100,000 barrels of fresh water per well for multi-stage fracking and that would be a daunting task at places of shale gas reserves, such as Cambay, Gondwana, and Krishna-Godavari, Cauvery, and the Indo-Gangetic plains due to water stress issues. Central & state Govts needs to ensure freshwater provisioning of this scale to the operators. US Govt with plenty of Fresh Water did not face this issue much. Government can think of a rainwater harvesting model in a big way and ask the operators to pay for the same. Once developed, The rain harvesting system could support local residents' drinking water needs.

Drilling, Fracking and formation water waste Disposal

Recent waste management technologies deployed in the US Shale gas ecosystem could be mentioned in licensing bid documents for compliance (Hübner et al. 2013).

Road infrastructure

Massive road infrastructure would be required, connecting the cities with nearby drill sites for movements of heavy machines and material and deployment cum movement of 40–50 pumping trucks per site. This would require a land acquisition cum road-building support process from state/district authorities.

Fear of Freshwater Contamination during Drilling

Shale gas technologies effectively circumvent these happenings. Operators would be asked through documentation and undertakings during the award of E&P contracts and licenses. This is a significant societal concern and Distt/state govts, with the help of operators, would convince society about the circumvention process and technologies (Ray 2013).

Open acreage bidding Rounds

Government of India needs to update itself fully, with all the US Shale gas Industry's learning evolutions and desired policy support interventions at various stages of Shale gas drilling, field development and production and transportation. India has recently introduced a new Hydrocarbon Exploration and Licensing Policy, which could go a long way to attract overseas investors at a time when only 19% of the total 3.14 million square kilometers have been extensively explored. However, it needs to be more lucrative from equipment import and domestic tax perspectives with added flexibility elements to make it more market and investor-friendly (Ray 2013).

Mid-stream interventions

Depending upon the locales of Shale gas occurrences in India, the GOI may require taking advance-tendering actions through Petroleum & Natural Gas Regulatory Board (PNGRB—Downstream Regulator) for the commissioning of the pipeline network as well as for city gas pipeline network.

Shale gas Services Network/Ecosystem

GOI may have to think of supporting the development and positioning of drilling, Hydrofracturing, production, gas transportation, and equipment manufacturing hubs near the central reservoir locations if India has to advance shale gas Industry development in a fast-track manner.

Cost of Shale Wells

Shale gas tends to cost more than Gas from conventional wells because of the expense of massive hydraulic fracturing required to produce shale gas and horizontal drilling. However, this is often offset by the low risk of shale gas wells. The cost of water treatment will be high and will impact the economics of the play (Ray 2013). The lack of proper and extensive pipeline infrastructure is another crucial bottleneck for the sector, as quick and safe transportation of Gas from the site to market is essential for the play.

7 Legal and Policy Status of Shale Gas: An Analysis

As per Indian Constitution, the Oil & Gas resources fall under the central government legislation and water resources are governed by the respective states. Under the NELP and HELP policy DGH on the advice of the Indian Government, allocates and facilitates the oil and gas block licenses and leases to bidding companies through competitive bid evaluation processes on level playing grounds (RTI Report, DGH 2023). Under the newly evolved policy reforms (HELP) all types of hydrocarbons in the prospects, including Conventional and/or Unconventional, could explored and developed in the allotted block under a singular license only (Prachur Jan. 2022). Under the Government's OPEN acreage policy, the Companies could choose any of the sedimentary basin/blocks of their choice to carry out any E&P operations, including Unconventional, under a well-defined program with total marketing and pricing freedom. Under the recent HELP and OLAP Policy, major reforms, and incentivization, namely—removal of differentiated royalties, exemption from oil/gas development cess and custom duties, 7-year tax holiday from Production commencement, the option to choose and construct the bid blocks of choice, moving away from production sharing Contracts to Revenue Sharing Contract model etc. have occurred in Shale Gas & other Petroleum prospects (RTI Reports, Directorate General of Hydrocarbon).

Considering that the Hydro fracture/fracking process differs from the other natural gas production processes, the Indian upstream Regulator (DGH) also released a "Draft Policy for the Exploration of Gas in India" in 2012 based on the advice of the Ministry of Petroleum & Natural Gas. The shale gas draft policy has focussed the strategic importance of shale gas fracking Technology in India, stressing that producing natural Gas from shale could play an increasingly important role in the Indian & global natural gas market. Policy highlighted the significant issues concerning shale gas fracking, primarily concerning the water-centric fresh problems in the unconventional gas Industry. DGH/MOPNG has recently released the Guidelines for Environmental Management during Shale Gas/Oil Exploration and Production to manage the natural resources and shale gas fracking process (MOPNG Report).

8 Conclusion

Innovative Technology Induction**:** Horizontal Slim hole Drilling, Hydrofracturing and Reservoir monitoring Technology Integrations combined with Sound Fiscal, Environmental and Infrastructure development Policies and industry driven laws of US along with government ownership and support on environment policies, have been the cornerstone of the US Shale Gas Success story. Fresh Water Aquifer Contamination while drilling and Societal concerns on wastewater and Chemical recycling and disposal (drilling and hydrofrak chemicals etc.) were effectively and timely addressed in USA through Govt motivation, intervention and support. Plenty of Barren Land availability in shale gas-rich basins was a boon for the USA, and government support in handing over processes from landowners in most basins was commendable and worth emulating globally. The council as mentioned earlier should build a study group to analyze (brick by brick) the entire evolutionary process of US Shale Gas success story.

Indian shale gas Industry has so far been sluggish and Government has realized its immense gas potential in India only a few years back. The regulatory framework, and unconventional/shale gas licensing policies need to be more proactive and industry-driven, as mentioned in the US model highlights above. The government and upstream regulator's commitment, ownership and facilitation in terms of land acquisition, freshwater availability, road infrastructure development, creation and facilitation of unconventional technology/ecosystem hubs and provisioning of fiscal benefits, market-driven gas pricing and other incidental policy reforms in entire shale Gas Value Chains in line with learnings from US model would create a desired ecosystem for scripting Shale gas success story for India.

Many region-specific innovations: New region-specific innovations will still be needed to adapt to new terrain and modify/customize US technologies and business integrations to efficiently and profitably exploit shale gas resources where Shale reservoir geology and water availability is significantly different. The Government of India should allow, motivate and incentivize every Oil company operating in India for pilot projects in shale gas in their already existing E&P blocks in different basins. It will help to understand the reservoir specific, geological attributes and behaviors of varying shale formations in different Indian basins. And it will generate the huge data set for formulating way forward and sustainable successes in shale gas exploration and development in India and neighboring regions. While India could benefit from existing cooperation with the US on shale gas exploration shortly, addressing 'above ground level' challenges, particularly concerning Fresh water availability and provisioning land for drilling, building hydro-frak Infrastructure, gas pipelines, etc., need to be prioritized through cooperative federalism and on fast-track basis as is being practiced in US Shale Gas Fields (Pradhan and Prakash 2015).

Of late Cairn Oil & Gas is collaborating with Halliburton in Barmer Formation of Rajasthan Basin for a big scale shale gas E&P project with an aim to accrete upto 3bn barrels and the partneship is expected to yield 300 mmboe of confirmed shale gas reserve base. India is yet to commercially produce shale derived gas and this strategic initiative from Cairn India-Halliburton should play a pivotal role in establishing the same. Shale gas has the "potential to be a game-changer for energy security of India, similar to what happened in the US". But the execution of shale projects will be much more costlier and technologically complex than the conventional ones, and the profitability will largely be dependent upon the supportive shale gas policy from the government. The lack of a viable fiscal policy is one of several challenges that have prevented commercial production of shale oil and gas in India.

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