

Shale Oil and Gas Plays: Indian Sedimentary Basins

P. K. Padhy and Shishir Kumar Das

(COD-Shale Gas, ONGC, Vadodara)

Abstract

Shale oil, shale gas constitute unconventional resource plays and are found in petroleum source rocks. Shale is considered as the conventional prime source facies for the naturally occurring hydrocarbons. These hydrocarbons are generated from organic rich shale under optimal temperature-pressure condition (thermal maturation) due to basin subsidence. A part of the generated hydrocarbons has been migrated and trapped in ideal locales constituting commercial accumulations. In case of shale oil/gas, shale acts as both source and reservoir rocks. Based on the type of organic matter and maturation level (either oil or gas window), the unconventional hydrocarbons could be shale oil or shale gas or a combination of both. The gas in shale are held as free gas within natural fractures, pore spaces and some are stored as adsorbed gas on the organic matter. As such, shale is characterized by low matrix permeability, and it requires hydraulic fracturing for shale gas production. Recent technological advancement in hydraulic fracturing and horizontal drilling has made shale gas exploration and exploitation economically viable.

There are number of active shale gas plays (Barnett, Eagleford, Haynesville Marcellus etc.) in US sedimentary basins and other parts of the world including India. Apart from North America (USA and Canada), shale gas exploration activities of varying geological age (Proterozoic to Cenozoic) are in full swing across all the continents such as South America (Argentina, Brazil), Africa (South Africa), Europe (Poland, Romania, Hungary and Germany) and Asia-Pacific (Saudi Arabia, China, Mongolia and Australia).

Shale occurs over the broad geological time scale, mainly in Proterozoic, Cambrian, Silurian, Devonian, Permian, Cretaceous and Paleogene-Neogene. Understanding of shale geology, its sedimentological and depositional settings in sedimentary basins merits due importance. The geochemical characteristics of shale reservoirs, mineralogical aspects, organic content, maturation, thermal history of the basin are some of the important parameters for evaluating the shale gas and oil potential. Generally the shale gas is characterized by high gamma value, high resistivity, low density and high porosity. Shale gas plays of the selected onland basins of India, analogous to the other world shale gas plays, have been enumerated.

Introduction

Shale gas constitutes an important unconventional source of natural gas stored in organic rich, matured fine grained sedimentary rock. The organic rich source rock on deep burial with geological time, results in conversion of organic matter into oil and natural gas. While a major part of oil and gas generated in shale is migrated, significant quantities are retained in-situ. Gas retained in a shale sequence is stored in natural fractures, pore space and as adsorbed gas on organic matters.

India is the 4th largest oil and gas consumer in the world after USA, China and Japan. The demand and supply energy scenario of India has been widening over the years. According Integrated Energy Policy brought out by Planning Commission in 2006, the total primary commercial energy requirement is projected to be in the range of 1437 to 1744 MMToe by the year 2030-31. Assuming the current energy mix (about 29% of oil and 11% of natural gas) to continue, oil and gas requirements of the country by 2030-31 is expected to be in the range of 418-506 and 158-192 MMToe respectively. Keeping in view the widening gap between demand and supply, the huge source rock deposits distributed in major petroliferous basins of Category I, Category II and even in Category III through wide range of geological sequence from Neo-Proterozoic to Cenozoic (Padhy and Naik, 1991) hold a lot of promise for shale gas/oil exploration.

The existence of natural gas in shale is known for a long time. The first commercial gas well drilled in the US in 1821 in Fredonia, New York was a shale gas well, producing from the Devonian Fredonia shale formation. Beginning in the late 1920s through the 1960s, thousands of wells were drilled into Devonian shales in the Appalachian region of the US. The first modern shale play that produced large quantities of gas was from the Barnett Shale in the Fort Worth Basin in north-central Texas. Mitchell Energy drilled the first Barnett Shale well in 1981. The first hydraulic fracture in the Barnett was performed in 1986. The Barnett Shale produces nearly 5 billion cubic feet per day (bcf/d). Current shale gas production in the US is over 10 bcf/d and about 1 bcf/d in Canada.

Characteristics of Shale Rock and Shale Gas

Shale is a fine-grained, fissile, detrital sedimentary rock formed by consolidation of clay (4 micron size) and silt-sized particles of other minerals, especially quartz and calcite into thin, relatively impermeable layers. It is composed of fine-grained detrital matrices of silt, clay-sized bits of organic matter, quartz, feldspars, clay minerals, calcite, dolomite and other minerals. Thus fine grained marlstones, dolostones and limestones have also received the name of shale. For example, in Bakken shale which is one of the largest shale oil deposits consists primarily of fine grained dolostone and limestone. The quality of shale reservoirs depends on their

thickness and extent, organic content, thermal maturity, fluid saturation, permeability etc. Various clay types and volumes influence the quality of the shale reservoir from the petrophysical and geomechanical perspective (Atkins et. al., 2011). Shale stores large amounts of organic materials compared with other rock types and are deposited under marine, fluvial and lacustrine environments.

The organic components of the shale are algae-plants and marine organisms. During burial, these organic matters (the kerogen) cracks to form hydrocarbons. The thermal process causes the organic matter to mature and the level of maturity determines whether the shale contains oil, gas or both. In the shale gas reservoirs, these complex matrices serve as the seal, reservoir and source for the gas.

The quantities of gas stored in the shale reservoir depends on specific source rock characteristics such as total organic carbon (TOC), thermal maturity, the type of kerogen present. Shale with high gamma (characteristics of rich organic matters), high resistivity, high TOC content (>2-3 wt %), high maturation value ($V_{ro} > 1.0$) is ideal for shale gas exploration. Source rock within low thermal maturity (oil window with V_{ro} ranging from 0.6-1.0) would yield mainly shale oil. The mineralogy of shale has direct bearing on the effectiveness of hydrofracturing for optimum production. The presence of certain minerals favours the generation of natural fractures. These create permeability pathways that connect the micropores and allow gas to flow. Natural fractures are more prevalent in silica-rich and carbonate-rich shales. The brittleness of the shale is the key factor in carrying out successful hydrofracturing and the operation can be monitored by microseismic survey.

Shale Gas Plays of Potential Indian Basins

The concept of exploration of unconventional hydrocarbons in India had been pioneered way back in early nineties (Padhy, 1989, Padhy and Naik, 1991) and later Mishra, 2008, Rao, 2010, Kumar, 2013 and others. As per the EIA study (2011), four Indian basins namely Cambay, Krishna-Godavari, Cauvery and Damodar are estimated to hold 63 TCF (Table-1). It may be noted that depending on the thermal history of the basin, there is possibility of exploration of both shale oil and gas from the sedimentary basins of India.

ONGC in collaboration with Schlumberger carried out a pilot shale gas project in Damodar valley which produced shale gas from the Barren Measure formation of Permian age. The first well RNSG-1 was spudded near Durgapur at Ichchapur (West Bengal) in Damodar basin on September 21,

2010 to explore shale gas. The main target Barren Measure shale was encountered from 985 to 1,843 meters. Gas flowed from an interval at a depth of around 1700m in Barren Measure Shale after hydrofracturing.

The four basins namely, Cambay, Krishna Godavari, Cauvery and Damodar are currently in focus for shale gas/oil exploration. Other Indian sedimentary basins such as Assam & Assam Arakan, Bengal, Pranhita Godavari, South Rewa, Satpura and Purnea basins also merit attention for shale gas exploration. Besides Permian to Cenozoic source rock facies, older stratigraphic shale sequences namely Suket, Hinota, Bijaigarh, Sirbu and Haimanta black shale of Vindhyan Super group (Neoproterozoic), Fenestella shale of Carbonaceous age, Daonella Carbonaceous Shale of Triassic and Spiti shale of Jurassic seem worth probing (Padhy, 1989, Padhy and Naik, 1991).

There are 26 sedimentary basins in India, which are considered prospective for oil and gas exploration. Of these, all the onland basins have significant thickness of shale sequences which need to be evaluated for their shale gas potential. Basins classified in the Category-I and II seem interesting from shale gas exploration point of view. Paleogene Shale Gas play of Cambay, Assam and Assam Arakan; Cretaceous Shale Gas Play of Krishna Godavari and Cauvery, Permian Gas Play of Krishna Godavari, Damodar and Satpura; Neoproterozoic-Cambrian Shale Gas Play of Ganga and Proterozoic Play of Vindhyan basins (Fig.1) have been briefly dealt. Geology of the major source rock facies, the geochemical aspects have been taken into account for envisaging the potential of shale gas in different basins (Table 2). It suggests that there is a considerable prospect in unconventional gas/oil in India.

Cambay Basin

The Cambay Basin is NNW-SSE Dharwarian trending intra-cratonic rift basin, situated in the western part of the Indian Shield. The sediment fill (Olpad formation) of Paleocene age represents the syn-rift stage of deposition. These sediments are characterized by poorly sorted high energy trap derived materials followed by widespread transgression during Early Eocene resulted in the deposition of thick dark, grey, fissile pyritiferous shale sequence, known as Cambay Shale. This shale sequence has been divided into Older and Younger Cambay Shale with an unconformity in between.

The Cambay Shale is the principal source facies in the Cambay Basin. The depth to the top of the Cambay Shale

Table 1: Perspective area if Indian Sedimentary basins and recoverable Shale gas reserves.

Basin	Area (sq miles)	Prospective Area (sq miles)	Risked Recoverable Reserves (TCF)	Remarks
Cambay	20,000	940	20	Four pilot wells were drilled in Damodar Valley by ONGC. One well, RNSG -1 flowed shale gas on testing.
Krishna-Godavari	7,800	4,340	27	
Cauvery	9,100	1,005	9	
Damodar	1,410	1,080	7	

Table 2: Details of the prospective shale gas/oil plays in different basins of India.

Basin/ Location	Shale Play Name	Age	Basin Areal Extent (onland) (km ²)	Thickness (m)	Depth (m)	TOC (%)	Tmax °C	VRo	Kerogen Type
Cambay Basin/	Cambay Shale	Paleocene to Eocene	55,000	500-2100	2000- 4000	1.0-4.0	415-431	0.6-1.2	II & III
	Olpad Shale	Lower Paleocene	55,000	1500 (Maxm)	2500- 4500	0.2-3.6	413-465	0.4-1.8	II & III
Krishna- Godavari Basin	Raghavap- uram Shale	Cretaceous	28,000	2000 (Maxm)	1200- 4500	1.0-4.7	430-514	1.0	II & III
	Kommugud- em Shale	Permian	28,000	1100 (Maxm)	1700- 4200	2.0-8.0	440-580	0.8-1.5	III
Cauvery Basin	Andimadam Formation	Albian	25,000	200-2400	1000- 5500	0.5-3.2	430-450	0.75	II & III
	Sattapadi Formation	Cenomanian	25,000	120-570	2000- 4000	1.0-3.0	435-450	0.6-1.13	II & III
Damodar Valley Sub-basin	Barren Measure	Middle Permian	820 (for Karnapur basin)	700	1500	3-6	427-474	1.1-1.3	III
Assam- Arakan Basin	Barail Coal Shale Unit	Upper Eocene to Oligocene	116,000	50-500	>2000	2.0- 12.0	410-450	0.45-0.7	III
Satpura Basin	Barakar	Early Permian	12,000	1200- 1500	2800- 6000	0.136- 29	321-533	0.42 -1.3	III
Ganga Basin	Ujhani Fm.	Ediacaran Lr.Ordovician	~3,00,0 00	250-1100	1272- 4700	0.66- 5.8	221-546	1.1	II and III(?)
Vindhyan Basin	Bijaigarh / Kaimur Shale	Neo-Meso- proterozoic	1,62,000	20-100	225-553	0.12 to 6.77	458	1.05 to 1.35	I & II
	Rohtas Limestone			63-1314	325- 1050	0.05 to 3.33	310 to 509		I & II
	Basuhari Glaucanite			162-960	616- 1295	0.02 to 3.0	310 to 450		I & II
	Charkaria Olive/ Hinota Shale			897-1220	933- 3452	0.02 to 10.5	408 to 463		I & II
	Jardepahar Porcellanite			743-1524	1929- 3147	0.01 to 4.39	415 to 441		I & II
	Kajrahat Limestone			512-1338	3085- 3860	0.03 to 8.08	445		I & II

ranges from about 2,000 m in the north to greater than 4500 m in the lows of the southern fault blocks. Average TOC values in Broach-Narmada Block varies from 1 to 3%, with high values being observed in Bharkhodra, Gandhar, Jambusar, Nada, Bharuch, Malpur areas. Peak maturation is observed in and around Bharuch, Jambusar, Nada areas and moderate

maturation observed in Narmada area. In Ahmedabad block, TOC values range from 1 to 3%; with very high values in Viraj, Nandasan, Limbodra, Dahegam areas. However in Mehsana-Patan block TOC values range from 1 to 4%, with very high values in Sobhasan, Unawa, South Patan, Dharnoj etc.

The Olpad formation, with slightly better source potential may be considered as a secondary target. The clay content of Cambay shale is found to be approx. 60%, which is on a higher side compared to established shale gas basins of US and Canada.

Krishna Godavari Basin

The basin has evolved over the Eastern Ghat tectonic grain in consequence of Indo-Antarctica plate separation during late Jurassic-early Cretaceous period. The pericratonic Krishna Godavari basin, towards northeastern part, overlies orthogonally the southern extension of northwest-southeast trending intracratonic Pranhita Godavari Gondwana graben and thus manifest poly-basinal evolution with typical tectono-sedimentary assemblages. The basin is characterized by wide sedimentological sequence from Permian to Recent.

Geologically wide range of organically rich shales is found, including Kommugudem Shale of Permian age. The Early Cretaceous High Gamma High Resistivity Shale (HG-HR, lower unit of Raghavapuram Shale) is the principal source facies. The Kommugudem Shale is characterized by alternating sequences of carbonaceous shale, coal and minor sand. The shale interval in Mandapeta graben ranges from 900 to 1100 m in thickness. However, HG-HR Shale unit, the Lower unit of Raghavapuram Shale of early Cretaceous age, is characterized by TOC contents of the range of 1.2-2.6, and it has higher generation potential values than the upper unit. Thickness of HG-HR is of the order of 1000m. Both Kommugudem and HG-HR sequences hold promising for shale gas exploration.

Cauvery Basin

The Cauvery rift basin is divided into a number of sub-parallel horst and graben trending in NE-SW direction. The basin came into existence as result of fragmentation of Gondwana land during drifting of India-Sri Lanka landmass system away from the Antarctica/Australia continental plate in Late Jurassic/Early Cretaceous time. The rift sediments range from Pre-Albian to Recent.

The early Cretaceous rocks of the Uttatur Group were deposited in marine environment and constitutes the Andimadam, Sattapadi and Bhuvanagiri formations in the subsurface. These formations overlie the older Gondwana rocks and basement granite gneisses. The Andimadam formation (Albian age) is developed mainly in Ramnad, Tanjor, Tranquebar, Ariyalur Pondicherry grabens and comprises of micaceous silty shale and sandstone. However, the Sattapadi formation (Cenomanian age) is widely distributed throughout the basin but is absent in the southern part. It contains mainly silty shale and thin calcareous sandstone. The Andimadam and Sattapadi are thought to be the main source rocks. The shale maxima of Andimadam formation trends in north-east south-west with thickness of 400m.

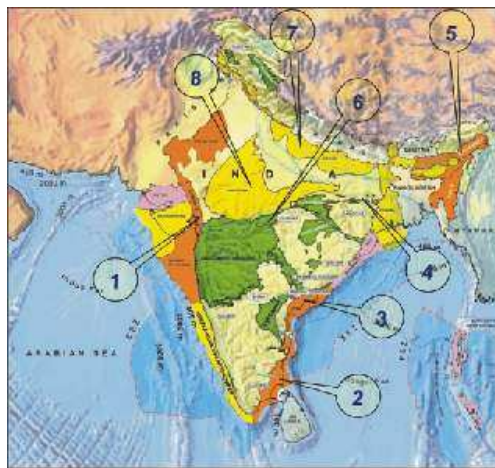


Fig. 1: Onland Shale Gas play of (1) Cambay, (2) Cauvery, (3) Krishna Godavari, (4) Damodar, (5) Assam and Assam Arakan, (6) Satpura, (7) Ganga and (8) Vindhyan basin

Damodar Basin

The Damodar Valley Basin comprises of a series of sub-basins (from west to east), the Hutar, Daltonganj, Auranga, Karanpura, Ramgarh, Bokaro, Jharia and Raniganj. Episodic erosion since the early Triassic has caused extensive variability in the depth and thickness of the Barren Measure Shale formation. Sedimentation in the Early Permian Gondwana basins was primarily glacio-fluvial and lacustrine, resulting in significant deposits of coal. The Barren Measure Shale formation of mid-Permian age is devoid of coal.

Thermal maturity data on coals surrounding the Barren Measure Shale suggest that it is within the gas window. Approximately 7 TCF of shale gas may be technically recoverable from the Barren Measure shale in this basin.

ONGC drilled two wells each in Raniganj and Kampura basins. Out of the two wells drilled in Raniganj, one well RNSG-1 flowed gas to the surface on testing and has given a way forward to the shale gas exploration programme. As per the estimates based on the two well data and its integration with the available G&G data, M/s Schlumberger estimated a total of 48 TCF of gas resource in the Barren Measure shale. However, results of two wells drilled in N Karanpura are not found to be immediate encouraging where only adsorbed gas has been shown to exist.

Assam and Assam Arakan Basin

The Assam and Assam Arakan Basin is a polycyclic sedimentary basin that witnessed two major phases of tectonic development. It developed as a composite shelf slope basinal system under passive margin setup during early Cretaceous to Oligocene, till collision of Indian plate with

Eurasian plate. During Miocene time the basin represents a foreland tectonic setting overriding the earlier passive margin sequence. The area within the Upper Assam Shelf covers an approximately 56,000 km² and contains about 7000m sediments of mostly Tertiary periods.

The main source sediments of Barail Group were deposited under moderately deep marine to deltaic environment. Major oil and gas has been found in the Barail Group of upper Eocene to lower Oligocene age and the Tipam Group of upper Miocene age. The important source rock sequences occur within the argillaceous Kopili formation (upper Eocene) and in the Coal-Shale Unit of the Barail Group.

The average TOC of the Barail Coal-Shale Unit is about 3.8%. The organic matter is of terrestrial type-III with varying contributions of Type-II. Barail Coal-Shale Unit in the Schuppen belt also forms important source rock sequence. In the Naga fold belt the Disang shale is characterised by presence of excellent source rock characteristics with TOC around 4% and VRo varying from 0.69% to 1.94%. It is envisaged that the source sequences within the Kopili and Barail formations in the subthrust would be at the peak oil generating state.

Satpura Basin

The east-west trending Satpura Basin is the westernmost Gondwana basin of Peninsular India with a sedimentary fill (>6500m) ranging in age from Permian to Cretaceous. Strike slip movements along the two dominant tectonic trends (Son-Narmada Lineament in the north and Pranhita-Godavari Fault in west) controlled the tectonic evolution of the basin, sediment deposition and also resulted in localised transpressional tectonics (Das et.al, 2006). The Gondwana sediments of the basin rest unconformably over an uneven surface of granitic gneiss of Archaean age. Presence of coals and black shales are widely observed and TOC of Barakar Formation found to be moderate to very good. Vitrinite reflectance studies suggest the Barakar Formations to be still within the oil/gas window. The nature of the organic matter varies from entirely gas-prone Type-III to upto 80% of algal and plant wax Type-II material in a few samples (Stoneley and Selley, 1996).

Ganga Basin

The Indo-gangatic plain represents a deep (>8000 m thick sediments) ranging in age from Mesoproterozoic to Recent. It extends from Delhi-Kalka ridge in the west to Monghyr-Saharsa ridge in the east, covering an area of ~300,000 Sq.km. The basin evolved through multiphase geologic history initiated with rifting during Mesoproterozoic and Late Neoproterozoic to passive margin during Late Eocene-Oligocene and finally culminating into foreland basin during Middle Miocene. Prevalence of Neoproterozoic petroleum system has been enumerated by Padhy, 1997, Das et. al, 2007.

Ujhani formation of Neoproterozoic-Lower Ordovician age comprises of carbonate-shale-sandstone and seems to be

more prospective. Mineralogical and sedimentological studies suggest that the Ujhani Formation sediments were deposited in a marginal marine to shallow marine environment. In Ganga basin, no commercial hydrocarbons have been discovered so far. Exploratory data generated in drilled wells indicates the presence of thin but organic-rich beds with good to fair hydrocarbon generation potential within the Ujhani Formation. The best organic-rich but thin source-beds were observed in wells Shahjahanpur-1 and Tisua-1 in Sarda Depression. The basal part of Ujhani formation around Tisua-1, Gandak-1 and Madhubani-1 and also in the deeper part further north of the basin appear to be attractive.

In Tisua-1, two mature source sequence at 2715-2740m and 2770-2790m with poor to fair (S₂: 0.86-2.7 mg HC/g rock) hydrocarbon generation potential has been identified. However, the organic richness in sediments is good to excellent (TOC: 1.72-5.8%). Thermal maturity based on T_{max} (440-472°C) and vitrinite reflectance (VRo: 1.1%) of Tisua-1 suggests that these intervals are in late peak mature oil window. The large stratigraphic thickness and area of Ujhani Formation especially in the northern deeper part of the basin offers the main source rock potential for generating reasonable volumes of hydrocarbons.

Vindhyan Basin

The Vindhyan Basin is located in the Central part of India and contains shallow marine deposits as thick as 6000m of Meso-Neoproterozoic age. The basin is bounded by Great boundary fault in north-west and Narmada Geofracture in south. Intrabasinal Bundelkhand massif divides the basin into two sub-basins: Son-Valley to the east and Chambal-Valley to the west.

Sandstone, shale and limestone are deposited in shallow marine environment. Presence of organic matter of algal origin fungi, acritarch remains and stromatolites in Vindhyan Basin suggests the type of organic matter of Type-I and II.

Bituminization studies suggested that Vindhyan sediments have passed the principal phase of oil generation. On the basis of absorbed hydrocarbon studies, it is inferred that the sediments have not reached the metagenesis stage. On the basis of organic matter maturation data, TAI values and TOC content that the Son Valley area holds better prospects both for Lower and Upper Vindhyan.

Prevalence of Neoproterozoic petroleum system of Vindhyan basin has been dealt in detail (Padhy, 1997, Das et. al., 2000, Padhy and Yalamarty, 2002). It is therefore concluded that the source rock potential of Vindhyan sediments viz., Kajrahat Limestone, Jardephar Porcellanite, Charkaria Olive Shale, Rohtas Limestone and Bijaigarh Shale are likely to have generated hydrocarbons and are in the wet to dry gas phase of thermal maturity, especially in the southern part.

Challenges

Shale gas exploration envisages both technical challenges and more so the environmental aspect. Drilling of hundreds of wells, defining proper trajectory for horizontal drilling, understanding of the geomechanical processes and massive hydrofracturing are some of the important factors that need attention. Availability of huge quantity of water for hydrofracturing, disposal of flow back water, water treatment etc are some of the key challenges. The high clay content (>50%) of the shale sequence of the sedimentary basins poses another challenge for effective hydrofracturing. Effective reservoir monitoring at nanoscale petrophysical properties, techno-economics etc are to be weighed for commercial viability of the shale gas.

Huge land acquisition could be another entity that needs to be carefully taken into consideration. Public awareness needs to be created for better understanding of socio-environmental issues.

Conclusions

Shale gas play could be one of the important resources for fossil fuel energy of India. Indian sedimentary basins have thick organic rich source sequences deposited over wide geological sequences. Permian and Cretaceous sequences appear promising and can be explored in different sedimentary basins namely Cambay, Cauvery, Krishna Godavari and Gondwanic basins. The Proterozoic basins namely Vindhyan and Ganga could also be potential targets. Holistic basin modeling is required for unearthing the huge potential of this unconventional resource. Proper planning and application of the state-of-the-art technology for evaluation, exploration and production need to be framed up keeping in view the environmental aspects.

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