

Integrated Study of Subsurface Core and Well Log to Characterize the Neogene Reservoir Sequences of Bengal Basin, Bangladesh

Md. Aminul ISLAM

UGC - 10537

Assistant Professor,
University of Rajshahi, Department of Geology and Mining

Japanese Advisor : Yujiro OGAWA
Professor, University of Tsukuba

The present study has been carried out to integrate the study of lithofacies, electrofacies, core petrography, diagenesis, core and well log petrophysics with a view to characterize the Neogene reservoir sequences of Bengal Basin. The relevant core and log data of Kailas Tila, Titas, Bakhrabad and Shahbazpur gas fields of Bengal Basin have been used for this study. Laboratory methods include thin section study, SEM, BSE, CL, XRD analysis; routine core analysis techniques introduced by Core Lab, USA. Log derived petrophysical calculations have been done with the help of different formulas postulated in the petroleum industry.

Lithofacies analysis confirmed twelve distinct lithofacies grouped into four major facies associations. The facies and facies sequence analysis of the core samples reveal that the detrital influx was contributed by a large fluvial system with strong evidence of tide dominated depositional processes. Multistory sand bodies, channel avulsion, erosional base sandstones reflect distributary channel sands of fluvial origin. Sharp base sandstones within siltstone and sandstone interbeds represent deposition took place in crevasse splay within interdistributary bay. Planer and cross bedding represent fluvial environment of deposition but lenticular, flaser, wavy bedding, mud drapes, bioturbation, bidirectional ripples and herring bone cross strata reflects strong tidal influence within the depositional setting. Over all coarsening upward sequences represent deltaic progradation.

It reveals from this study that bell, funnel, egg/bow, linear shape electrofacies are common whereas cylindrical shape appears as less common. Bell shape represents fining up sequences and funnel shape indicates coarsening up sequences. The log cycles indicate over all deltaic progradation. Fining and coarsening upward second order cycles indicate autocyclic change of deposition due to lateral migration of depositing medium within the basin. Large scale fining and coarsening upward first order cycles indicate allocyclic change of deposition due to tectonic subsidence and eustatic sea level changes. The depositional model for the sediments encountered in the studied wells has been considered to be that of a lower delta plain to outer shore face with a range of facies typical of fluvio-deltaic to tidal environments. Potential reservoir sandstones were the characteristic deposits of fluvio-deltaic distributary channels, crevasse splay, distributary mouth

bars, tidal sand flat, tidal channels and tidal ridges. Bell, funnel and egg/bow shape indicate good quality reservoir rocks are located at the base, top and middle of the electrofacies respectively. Deltaic prograding sequences are reservoir sand dominating and retrogradational or transgressive sequences are shale dominating.

The reservoir sandstones of the study area are mostly very fine, fine to medium grained; subangular to subrounded, moderately well to well sorted sublithic arenite, feldspathic arenite and lithic arenite in order of abundance. Quartz, feldspar and lithic fragments are the main detrital framework grains that constitutes 51 to 60%, 3 to 15% and 8 to 22% respectively. Recalculated detrital components are characterized by $Q_{69}F_{15}L_{14}$. Detrital grains suggest granitic as well as sedimentary and low-grade metamorphic source terrains. Polycrystalline quartz of metamorphic origin is also common. Different triangular plots indicate that the sands were derived from quartzose recycled orogenic province, such as a fold thrust province or a collision suture zone. Either the eastern Himalayas or Indo-Burman Ranges might act as the source of the sediments of the studied wells of the Bengal Basin.

The dominant diagenetic cements are ferroan calcite, quartz overgrowth, authigenic chlorite and kaolinite that constitute on average 3.1%, 1.6%, 1.4% and 1.3%, respectively. Compaction reduces the original porosity and permeability of the reservoir sandstones. The reservoir properties of the sandstones are largely affected by cementation. Higher volume of calcite cement (>15%) acts as potential barrier to fluid flow where helium porosity falls to <5% and horizontal permeability <8 mD. Quartz cement acts as an important reservoir quality deteriorating mechanism. Pressure solution developed at the grain contacts is the dominant source of quartz cement. Pore lining and pore bridging chlorites and authigenic kaolinite prevent fluid flow through the intergranular macro pores that also may present irreducible water saturation traps. Chlorite occurs due to the breakdown of mica and lithic fragments. Alteration of feldspar is the principal source of kaolinite cement. Secondary porosity developed due to dissolution of plagioclase, potassium feldspar, rock fragments, authigenic cements like calcite, dolomite etc. Paragenetic sequence include early phase of clay infiltration, compaction, development of chlorite, pyrite and illite followed by K-feldspar overgrowth, poikilotopic calcite and dolomite cementation, development of pressure solution. The late diagenesis includes dissolution and leaching of feldspar, quartz overgrowth, and grain replacement by late calcite and authigenic kaolinite formation.

Core analysis results show that average core porosity, permeability and pore throat values are 20%, 209 mD and 44020 Å, respectively. These measured values support that the sandstone reservoirs are categorized as good quality reservoirs. Core porosity values usually exceed thin section porosity (8.7%). Different cross-plots indicate that permeability is largely dependent on porosity. Permeability and

porosity are also dependent on textural parameters like size, sorting and matrix of the reservoir sandstones. It reveals from both thin section study and different cross plots that diagenetic cements are the main controlling factors of the reservoirs. Quantitative determination of the volume of cements shows that cements have inverse correlation with porosity and permeability. Log petrophysical parameters include shale volume, porosity, water and hydrocarbon saturation, permeability, moveability index and bulk volume of water. The average values of the mentioned parameters are 20%, 22%, 26%, 74%, 110 mD, 0.28 and 0.05, respectively. The most important parameters are porosity and permeability which indicate that log porosity exceeds core porosity and log permeability significantly lags behind core permeability. The study also reveals that 23 gas zones covering total thickness of 385 m sandstones mostly possess good quality reservoirs except few moderate quality reservoirs.

