PS: An Overview of Geochemical Exploration of Hydrocarbons
in Papuan Basin, Papua New Guinea*

Shadrach K. Noku1

Search and Discovery Article #11326 (2020)**
Posted May 25, 2020

*Adapted from poster presentation given at 1st AAPG/EAGE PNG Geoscience Conference & Exhibition, PNG’s Oil and Gas Industry Maturing Through Exploration, Development and Production, Port Moresby, Papua New Guinea, February 25-27, 2020

**Datapages © 2020. Serial rights given by author. For all other rights contact author directly. DOI:10.1306/11326Noku2020

1Kumul Petroleum Holdings Ltd., Papua, New Guinea (SNoku@kumulpetroleum.com)

Abstract

Papua New Guinea has five sedimentary basins of which only one (Papuan basin) is a producing basin. Exploration efforts in the larger Papuan basin has been in progress for decades. The larger Papuan basin is characterized by varied geology, age, tectonics and depositional environments. Hydrocarbon shows, oil and gas discoveries in commercial, sub-commercial and non-commercial quantities have been made. Petroleum production is limited to the highlands of Papuan fold belt at present. Exploration for hydrocarbon in Papuan basin is challenging due to structural complexity, poor-fair quality seismic and limited dataset. The purpose of this study is to evaluate source rock and hydrocarbon geochemical data available to improve our understanding of burial history, maturity, timing of hydrocarbon generation and migration. This will help constrain opportunities to develop new petroleum charge models for geological features across the Papuan basin and to lower exploration risk. The present-day oil accumulations in the Papuan fold belt fields such as Kutubu (Iagifu, Hedinia) and Gobe are thought to be derived from clay-rich, Jurassic marine source rocks containing mixed algal–terrigenous organic matter that were deposited in oxic environments possibly along shelf slopes. The co-reservoired natural gases suggest a substantial gas input from the basinal facies further to the north/northwest, reflecting relatively more marine-influence, high maturity, and cracking-genesis attributes. The basinal facies of Jurassic source rocks may have only contributed highly mature gas-condensate to the current deposits (Hides, Juha, P’nyang), however, implying a loss of the earlier-generated black oils. Published data for geochemical characteristics of recovered oils, oil extracts, fluid inclusion oils, condensates, and oil/gas seeps suggest two major families of hydrocarbons occurring in both the western and eastern Papuan basin regions. Hydrocarbons in the western region (Papuan foreland) were likely sourced from Late Triassic and Late Jurassic clay-rich marine source rocks containing terrigenous higher plant derived organic matter (OM) deposited in a sub-oxic to oxic environments. Five oil families and two charge events have been modelled based on the geochemical data. Hydrocarbons distributed in the eastern region were generated from Cretaceous or younger marine carbonate source rocks deposited in an anoxic to sub-oxic conditions. Biomarker characteristics of solid bitumen extracts from Late Cretaceous Pale and Subu sandstones indicate two separate oil charges. One (family A) is from a strongly terrestrial influenced marine source rock that may well be Jurassic in age whereas the other (family B) originated from a marine source rock with a calcareous component, with a high proportion of prokaryotic OM and a low proportion of terrestrial higher plant inputs. The Mesozoic rift basin of Gulf of Papua (GoP) contain more gas than oil because the Middle-Upper
Jurassic or Lower Cretaceous marine source rocks have mixed gas-oil potential. The quality of source rocks is fair to good, typically averaging 150–300 mg HC/g rock HI and 1–2% TOC, with good average thickness of 2–3km. The Jurassic source rocks in the GoP have generated petroleum in two discrete pulses, the first at the end of the Cretaceous and the second at the end of Cenozoic where the end-Cretaceous pulse was volumetrically more important. Mesozoic hydrocarbons draining into Tertiary reef traps were limited because reefs were not present however, the gas-condensates accumulation in Tertiary reefal carbonates were derived from the depleted Jurassic source rocks during the Late Cenozoic generation and migration. Numerous studies on hydrocarbon characteristics from the larger Papuan basin indicate that the hydrocarbons are not homogeneous and display variabilities. The variabilities are likely to be a function of lateral and vertical changes in both organic facies and source rock maturity.
Introduction

Petroleum exploration has a long history in Papua New Guinea (PNG), with the first well, specimen 1, drilled in 1912 (Rickard, 1969). Exploration efforts in the larger Papuan basin have been for decades and focused on prospects of Mesozoic and Tertiary age. The largest Papuan basin is characterized by varied geology, age, tectonics and depositional environments. Typical reservoir rocks are Late Jurassic-Early Cretaceous carbonates to equivalent sandstones and Miocene carbonates. These reservoirs are amalgamated by Mid-Late Jurassic organic rich marls (types II and III shales) (i.e. Madugu Coal, Barikewa, Med and Imburu Formations).

Geochemical data of oil, gas and source rocks suggest hydrocarbons in the larger Papuan basin have a variety of origins. Oil accumulations in fields such as Kukula, Moten and Gobe are thought to be mainly derived from clay-rich, Jurassic marine source rocks containing tenuously-detected organic matter that were deposited under anoxic conditions. Organic geochemical data of hydrocarbons from Papuan foreland basin suggest these different source rocks are either Cretaceous marine source rocks deposited in an anoxic environment, or the carbonates and associated source rocks, or clay rich source rocks deposited in a suboxic environment. Hydrocarbons in the Eastern Papuan basin (EPB) are generated from sources of Jurassic age enriched in clay and terrestrial organic matter deposited in a reducing environment. Hydrocarbons discovered in the Gulf of Papua (Gup) are believed to be generated from Q1-deep marine mudrocks rich in the remains of land plants and Miocene shales.

The purpose of this study is to evaluate source rocks and hydrocarbon geochemical data available to improve our understanding of burial history, maturity, timing and hydrocarbon generation and migration. This will help operators appreciate in developing new petroleum plays models for geologic features across the Papuan basin and to better exploration efforts.

Petroleum Potential of Source Rocks

The potential of source rocks is determined by their thermal maturity, organic richness, and the aromatic richness of the organic matter.

Thermal Maturity

Thermal maturity is a measure of the degree of transformation undergone by organic matter due to heat and time. It is typically expressed as vitrinite reflectance (%R0) or Rock Eval Tmax. Minimum values of vitrinite reflectance (%R0) are used for determining the maturity of source rocks. The %R0 values range from 0% to 100% where 0% represents immature source rock and 100% represents mature source rock.

Organic Facies

Organic facies is a measure of the type of organic matter present in a source rock and is typically divided into three main categories: terrestrial, lacustrine, and marine.

Genetic Characterization of Hydrocarbons

The genetic characterization of hydrocarbons is typically determined by analyzing the isotopic composition of carbon, hydrogen, and nitrogen in the hydrocarbons.

Concluding Summary

Jurassic and Cretaceous sedimentary rocks are the key source rocks for oil in the entire basin. The source rocks have been deeply buried and are distributed in the Amazonian and Andean provinces, and are thought to be the source of the oil found in the region.