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REGIONAL PETROLEUM GEOCHEMISTRY OF INDONESIAN BASINS: UPDATED, AND IMPLICATIONS FOR FUTURE EXPLORATION

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ABSTRACT

Petroleum geochemistry of Indonesian basins is overviewed regionally for their oil and gas characteristics, and their proven sources. Published literatures and recent analyses of oils and gases from various areas in Indonesia are used to update the synthesis.

Regionally, oils of Western Indonesian basins can be grouped into three broad families: (1) lacustrine (Central Sumatra, Sunda-Asri, partly West Natuna, and West Sulawesi Offshore/North Makassar Straits), (2) fluvio-deltaic (South Sumatra, West Java, East Java, Barito, Kutai, and Tarakan), and (3) marginal-shallow marine (North Sumatra and West Sulawesi Onshore). The interpreteted source rocks for most of these basins/areas are Paleogene age shales, coaly shales, and marginal-shallow marine shales and carbonates. The source rocks of the Kutai and Tarakan basins are interpreted to be Neogene age coaly shales and coals. Most of the oils from Eastern Indonesia basins/areas are marginal-shallow marine; sourced by Neogene shales, marls, carbonates (Salawati, Banggai) or Jurassic marine shales (Bintuni), Triassic-Jurassic marine shales (Timor, Buton) or Triassic-Jurassic carbonates (Seram, Timor).

Both thermogenic and biogenic (bacterial) gas types can be recognized in Indonesia. Mixing between the two types is also commonly observed. Thermogenic gases are distributed in the basins of Sumatra, Natuna, Java, Kalimantan, Makassar Straits, Sulawesi, Papua, and Timor-Arafura. Biogenic gases are found mainly in: the fore-arc basins west of Sumatra, East Java Basin, and the foredeep area of the Sorong Fault Zone, northern Papua. High concentrations of non-hydrocarbon CO_2 mainly occur in North and South Sumatra, East Natuna, and onshore Java; whereas H_2S concentrations are moderate to high in some gas fields in North Sumatra, South Sumatra, East Java, East Sulawesi and Salawati Basins.

Some current petroleum geochemistry issues are observed, they include: Paleogene oil seeps in Java's volcanic areas, marine Mesozoic oil in East Java Basin, Cenozoic oil and Pre-Cenozoic gas of Banggai-Sula area, Neogene proven source rocks of Buton area, Neogene oil seep of Northern Papua, and the application of molecular biomarkers for regional tectonic studies of Indonesia.

Geochemistry has significant contribution to exploration efficiency, because it shows genetic relationships among crude oils and source rocks. Knowing precisely what the proven source is in a basin, can help building right systematic exploration strategy for the basin.

INTRODUCTION

There have been several previous regional studies on petroleum geochemistry of Indonesian basins. Regional overview of petroleum geochemistry of Indonesian sedimentary basins was firstly published by Robinson (1987), characterizing source rocks and oils in Indonesia based on their geochemical properties. Livsey et al. (1992) detailed the petroleum geochemistry of Eastern Indonesian sedimentary basins for Tertiary and pre-Tertiary source rocks and their associated oils. Peters et al. (1999) grouped the oils in Eastern Indonesian sedimentary basins based on their isotope and biomarkers signatures. Satyana and Purwaningsih (2013) updated the knowledge on source facies of Western Indonesia sedimentary basins based on oil biomarkers. The first attempt to do regional overview of genetically typing Indonesian gases was published by Satyana et al. (2007).

Discussions on petroleum geochemistry of Indonesian basins, especially for their sources, appear also in regional studies of petroleum systems of Indonesian basins. The first regional study on this was published by Howes and Tisnawijaya (1995), discussing Indonesian petroleum systems, reserve additions, and exploration efficiency; and ten Haven and Schiefelbein (1995), discussing geochemical characteristics of oils and the source rocks and their palaeoenvironmental conditions. The updated

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knowledge on this was published by Doust and Noble (2008). More regional overview on the petroleum systems of Indonesia in regional context of Southeast Asia was published by Howes (1997), Schiefelbein et al. (1997), Howes (2001), and Doust and Sumner (2007).

In addition to these regional overviews there have been numerous past and recent studies encompassing more local areas with specific issues on petroleum geochemistry of the areas, discussing their sources, oils, or gases. Some recent local geochemical studies, for examples, were published by Sutanto et al. (2015) and Satyana (2016), discussing the presence of Mesozoic oil in East Java Basin based on biomarker characteristics, and Satyana and Zaitun (2016), discussing the oil and gas grouping of Banggai-Sula area, East Sulawesi.

This paper aims to compile these previous regional and local petroleum geochemistry studies, updated by the current issues, presenting regional synthesis of petroleum geochemistry of Indonesian sedimentary basins with some current issues which develop based on current geochemical analyses.

DATA & METHODS

Published papers on petroleum geochemistry and petroleum system of Indonesia basins both in regional and local scopes of discussions, unpublished reports of geochemical analyses and studies, past and recent, conducted by oil companies operating in Indonesia, form the main data for this study. They are reviewed to compile the knowledge on updated regional petroleum geochemistry of Indonesia basins and some current issues on the field important to know.

The discussion will be addressed sequentially as follows: (1) role of petroleum geochemistry, (2) regional oil families and related sources of Western Indonesian basins, (3) regional oil families and related sources of Eastern Indonesian basins, (4) gas geochemistry of Indonesian basins, (5) some current geochemical issues, and (6) implications for future exploration.

RESULTS & DISCUSSIONS

Role of Petroleum Geochemistry

With the advent of integrated petroleum system analysis in the method of petroleum exploration since 1990’s, the awareness of geoscientists on petroleum geochemistry has improved significantly. This because the ability to identify a petroleum system uniquely depends on geochemical techniques needed to characterize petroleum, and to carry out petroleum-petroleum and petroleum-source rocks correlation (Magoon and Dow, 1994).

Reducing the exploration risk depends not only on finding a trap but also on determining how high the probability is that oil has migrated from a mature source rock into that trap and has not escaped or been destroyed (Hunt, 1996). This issue concerns with petroleum geochemistry.

Demaison (1984) summarized that successful exploration depends on the simultaneous occurrence of the three independent factors: (1) the existence of a trap (structure, reservoir, seal); (2) the accumulation of a petroleum charge (source, maturation, migration to trap, timing); and (3) the preservation of the entrapped petroleum (thermal history, meteoric water invasion). Factors no. (2) and (3) concern with petroleum geochemistry. In the integrated petroleum system analysis, these three independent factors are related to each other building a system. The probability of success in finding petroleum is the product of the probabilities of all three of these factors. Therefore, if anyone is zero, a “dry hole” will be the result, no matter how favorable are the other two factors (Hunt, 1996).

Areas of concentrated petroleum occurrence can be predicted using mapping methods that integrate geology, geophysics, and geochemistry (Demaison, 1984). Biomarkers – used mostly in this study - are powerful component in this petroleum exploration approach (Peters at al., 2005). Combined with other exploration tools, biomarker geochemistry significantly reduces the risk associated with exploration for petroleum. The single most significant contribution of geochemistry to exploration efficiency is that it can be used to show genetic relationships among crude oils and source rocks. Geochemistry also increases exploration efficiency by accounting for many of the variables that control the volumes of petroleum available for entrapment (charge), including source-rock quality and richness, thermal maturity, and the timing of generation-migration-accumulation relative to trap formation.

Geochemistry is most powerful when used with other disciplines, such as seismic sequence stratigraphy and reservoir characterization (Peters et al., 2005). Including geochemistry in prospect appraisal improves exploration efficiency. Forecasting efficiency based only on structural and reservoir data approximately doubles when geochemical charge and retention parameters are included in prospect evaluation. Costly exploration failures are painful reminders that large structures indicated by seismic data may lack oil and gas due to geochemical charge factors.

Knowing the significance of petroleum geochemistry for exploration efficiency and success, therefore the knowledge on geochemical aspects of sedimentary basins is important. Knowing precisely what the proven petroleum-generated source is in a basin, it can help to build right systematic exploration strategy of the basin. This paper will integrate regional petroleum geochemistry of oils and gases, and their proven sources in sedimentary basins of Indonesia, as well as some current geochemical issues, needed to know for further exploration of Indonesian basins.

Oil Families and Their Sources of Western Indonesian Basins

The area of Western Indonesian basins discussed here includes Sumatra, Java, Natuna, Kalimantan, the Makassar Straits, and West Sulawesi.

Robinson (1987) was the first who published oil and source rock characterization in Indonesia and proposed their classifications. As for Western Indonesian basins, he classified crude oils into: lacustrine, fluvio-deltaic and marine based on a range of geochemical parameters, including pyrolysis-gas chromatography on the oils asphaltene fraction and GC-MS biomarker data (Figure 1). Lacustrine source rocks are the most productive, and have sourced most of the oil in Central Sumatra, some of the oil in the Sunda Basin and also possibly oil in the West Natuna Basin. Fluvial-deltaic source rocks are the most common and widely dispersed and have sourced oil in the majority of basins of Western Indonesia. Marine source rocks in combination with fluvio-deltaic source rocks charged the oils in North Sumatra Basin.

Robinson (1987) work was updated by Satyana and Purwaningsih (2013) using updated data and with focuson biomarkers of oils in each basin. New areas were not discussed by Robinson (1987), was discussed by the presence of new data, including the Makassar Straits and West Sulawesi (Figure 2). Satyana and Purwaningsih (2013) found the Robinson (1987)'s classification of lacustrine, fluvio-deltaic, and marine for oils and their sources can still be used for updated data but with some modifications. Satyana and Purwaningsih (2013) also attempted to show that oil biomarkers can confirm or examine the tectonic and sedimentary models proposed for the origins and geologic histories of the basins.

The sedimentary basins of Western Indonesia (North Sumatra, Central Sumatra, South Sumatra, Sunda-Asri, West Java, East Java, Barito, and West Natuna) produce oils from Paleogene and Neogene reservoirs, but the oils were generated and expelledfrom Paleogene source rocks as suggested by several basin models (refer….). Oils discovered by the recent well in the Makassar Straits and numerous seeps in West Sulawesi were also generated from the Paleogene sources. Kutai Basin produces oil generated from the Neogene deltaic sources, whereas its Paleogene source is not known yet generated oil due to these rocks are very deeply buried by the stacks of Neogene deltaic sediments.

Paleogene source rocks that have expelledhydrocarbons in Sundaland basins vary from organic rich lacustrine facies to carbonaceous shales and coals of fluvio-deltaic, paralic and marginal marine and marine facies. Most of the lacustrine source rock facies were deposited during the middle-phase to the end of post-rift phase while other source rock types were developed at the end of the post-rift phase concurrently with marine incursion events. Multiple source rock facies are possible in a single Paleogene basin, but commonly only a single major source rock facies is present in any one basin.

As Robinson (1987)'s classification, Satyana and Purwaningsih (2013) and recent reinterpretation found that based on their oil characteristics, the basins in Western Indonesian can be classified into (see Figure 2): (1) basins with predominating lacustrine and subordinate fluvio-deltaic source facies (Central Sumatra – Eocene-Oligocene Pematang source, Sunda-Asri – Eocene-Oligocene Banuwati source, West Natuna – Eocene-Oligocene Lama-Benua-Belut-Lower Gabus source, North Makassar Straits – Eocene source); (2) basins with predominating fluvio-deltaic source facies (South Sumatra – Oligocene Talang Akar source, West Java - Oligocene Talang Akar source, East Java – Eocene Ngimbang source, Barito – Eocene Tanjung source, Kutai – Miocene Balikpapan source, Tarakan – Miocene Meliat-Tabul source); (3) basins with predominating marginal-shallow marine source facies (North Sumatra – Oligocene Bampo source; West Sulawesi – Eocene Kalumpang source).

Geochemical characteristics of oils in each classification can be read from Robinson (1987) and Satyana and Purwaningsih (2013). In summary:

1. Lacustrine oils sourced from non-marine algae are generally low-medium gravity, waxy, low sulfur oils. The characteristics are bimodal to broad n-alkane distribution due to input of C_{15}-C_{19} and C_{23}-C_{33} n-alkanes from non-marine algae, low Pr/Ph ratios < 3.0 and have low Pristane/nC_{17} ratios. Lacustrine oils are typically high wax (C_{31}/C_{19} > 0.4). Deep lacustrine sourced-oils tend to have simple triterpane distributions containing only pentacyclic 17α hopanes from C_{27}-C_{35} plus moretanes and little else. The Tm/Ts ratio, which is maturity and organic facies influenced, is low and enriched in tricyclic terpanes. The oils also often contain unusually high concentrations of C_{30} 4-methyl steranes.

2. Marine oils derived from marine algae are low medium gravity, low wax, medium-high sulfur oils and contain C_{27}-C_{29} diasteranes and steranes in relatively high concentrations compared to other oil types. GC scans show decreasing concentration of higher molecular weight n-alkanes (low wax content), Pr/Ph < 3.0, Pr/ C17 ratio < 1.0, low wax (< 0.4 C_{31}/C_{19}). Triterpane scans have relatively simple hopane and moretane distributions, Tm/Ts values range from 3.0 to 1.0. There is content of 18α oleanane, indicating transportation of resistant higher plant resins into marine basin and not indicative of a terrestrial source for the oil. Noticeable other C_{30} resin derived compounds, commonly found in association with oleanane, are absent or in very low concentrations. Marine oils of North Sumatra are also indicated by relatively high concentrations of tricyclic terpanes. Based on steranes, isomer C_{27} dominates the distribution, indicating marine facies. The more abundance of C_{27} steranes is often associated with an algal input. Pentacyclic terpane showing C_{29} norhopane/C_{30} norhopane ratio >1.0, indicating carbonate source in addition to marine shales as indicated by C_{29} norhopane/C_{30} hopane ratio <1.0.

3. Fluvio-deltaic oils derived from higher plant, terrestrial organic matter are medium-high gravity, waxy, low sulfur oils. GC alkane and GC/MS of triterpane m/z 191 and sterane m/z 217 show high Pr/Ph and Pr/nC_{17} ratios, presence of high concentrations of C_{30} compound 18α oleanane and bicadinane. Bicadinane derives from angiosperm dammar resins of some SE Asian higher land plants (Peters and Moldowan, 1993), characterizing fluvio-deltaic environment. They contain abundant higher plant resin derived C_{30} alkanes and low concentrations of steranes which are dominated by C_{29} diasteranes and steranes. Fluvio-deltaic oils have minimum tricyclic terpane. Oils from deep-water Kutai and North Makassar Basin also show characteristics of fluvio-deltaic oils since the oils were sourced by transported fluvio-deltaic sources redeposited in deep-water area. This will also the case for deep-water Tarakan Basin.

Oil Families and Their Sources of Eastern Indonesian Basins

Robinson (1987) expected that marine source rocks probably occur in Eastern Indonesia, but this assumption was poorly documented. Marine source rocks may be at the origin of oil in the Salawati Basin and eastern Sulawesi. Positively identified active source rocks are all Tertiary in age, although Pre-Tertiary (Permian/Jurassic) rocks are suspected to source oil in the Bintuni and Bula (Seram) Basins and are also a possible source in eastern Sulawesi and the Banggai-Sula area east of Sulawesi.

Robinson (1987) expectation was confirmed by Livsey et al. (1992) based on additional exploration results in Eastern Indonesia from the late 1980's. Later study based on new oil analyses lead Peters et al. (1999) creating oil families in Eastern Indonesian basins.

Based on extensive analyses of well sections and field samples from Eastern Indonesia, Livsey et al. (1992) identified source rocks range in age from Pliocene to Cambrian, primarily in basins with Australian crustal affinity. Geochemical analyses of selected tested oils and oil seeps also allowed correlation of these oils with possible source rocks. Pre-Tertiary source rocks are widespread in Eastern Indonesia but source rock deposition has been mainly restricted to three time periods: the Late Permian, the Late Triassic, and the Early-Middle Jurassic. Source rocks range from fluvio-lacustrine shales and coals to marine carbonates and shales, which have been correlated with oils from the area. Tertiary source rocks have accumulated in several basins during the Middle-Upper Miocene and Pliocene and show many similarities to fluvio-deltaic coals in Western Indonesia. In the Salawati and Tomori Basins, however, source rocks comprise interbedded coals, calcareous shales and argillaceous limestones containing a mixture of marine-derived and terrestrial organic matter. These source rocks have been correlated with tested oils from the basins.

Peters et al. (1999) analyzed crude oils from Eastern Indonesia and proposed their families based on high-resolution geochemistry showing genetic relationships among the crude oils and suggested the ages and paleo-environments of their source rocks (Figures 3-5). Oils inferred to originate from Tertiary and Triassic–Jurassic source rocks in the study occur north and south of 2°S latitude, respectively. Most of the source paleo-environments are marine, with lithology sources are shales, marls, and carbonates.

Low-sulfur shallow oil from Miocene Kais reservoirs in the Wiriagar field (Group 1) in Bintuni Basin is highly mature, and has undergone extensive migration fractionation. The shallow Wiriagar oil lacks oleanane, consistent with a Jurassic or older marine source rock, and contains high 24-n-propylcholestanes (C_{30} steranes) (Figure 4). The C_{30} 24-n-propylcholestanes are diagnostic of marine source rock depositional environments. The isotopic compositions of the saturated and aromatic hydrocarbons for this oil are consistent with a Mesozoic source rock but are not typical of Tertiary or Paleozoic oils (Chung et al., 1992) (Figure 5). This oil probably originated from synrift-postrift Lower–Middle Jurassic Kembelangan Formation clay-rich shales that contained mixed type II/III kerogen deposited under oxic conditions. The shallow Wiriagar accumulation accounts for about 5%, whereas the deep Wiriagar accumulation (gas) accounts for about 77% of the estimated ultimate recovery in eastern Indonesia.

Twenty oils mainly from Salawati and Banggai basins (called Groups 2 - Matoa, Linda, Klamono, Klalin, Kasim, Kasim Barat, Cendrawasih, Jaya, Minahaki-Banggai, Southwest O oils; and Group 3 - Walio, Kolo seep –Banggai) originated from Tertiary marine marlstone source rocks that contained type II/III kerogen deposited under suboxic conditions, probably the upper Miocene source. They show high oleanane ratios and C_{30} 24-n-propylcholestanes that are diagnostic of a Tertiary marine source rock (Figure 4). Oleanane/ (oleanane + hopane) ratios over 0.20 in oils are diagnostic of Tertiary source rock (Moldowan et al., 1994). Another age-related biomarker ratio provides independent support for the interpretation of Tertiary source rock. All group 2 and 3 oils show high 24-nordiacholestane ratios (0.25–0.40 and 0.27–0.35, respectively) where ratios greater than 0.25 are diagnostic of oils from Cretaceous or Tertiary source rocks (Holba et al., 1998). Furthermore, the saturated and aromatic hydrocarbons for group 2 and 3 oils are enriched in 13C, typical of Oligocene–Miocene rather than Mesozoic oils (Chung et al., 1992). The stable carbon isotope compositions of saturated and aromatic hydrocarbons for these oils and the resulting calculated canonical variables (CV) indicate mostly marine organic matter in their source rocks (Figure 5). Most group 2 and 3 oils show moderate diasterane ratios (20–40%), suggesting a calcareous claystone or marlstone source rock with clay content between pure carbonate and clay-rich siliciclastic. These oils account for about 16% of the estimated ultimate recoverable reserves in eastern Indonesia.

Five oils from Seram (Group 4A –Bula, East Nief) originated from Triassic–Jurassic marine carbonate source rock that contained type II kerogen deposited under anoxic conditions with low pristane/phytane ratios. These high-sulfur oils lack oleanane and generally show low C_{26} 24-nordiacholestane (Figure 4). Carbonate source for these oils are shown by low diasterane ratios (8–18%), low tricyclic terpanes, high norhopane/hopane ratios, high 30-norhopanes, and high sulfur (0.94–2.95 wt. %). Higher Pr/Ph ratio (1.58) and low sulfur (0.08 wt. %) for the Aliambata oil seep (Group 4B) from Timor suggest a suboxic source rock depositional environment originated from type II/III kerogen in a more oxic, terrigenous-influenced marine environment. The high diasterane ratio for the Aliambata oil (45%) indicates a clay-rich source rock, which is supported by the low sulfur content. Stable carbon isotopic compositions for the saturated and aromatic hydrocarbon fractions of the group 4 oils are depleted in 13C compared to the other oils in the study and are typical of Mesozoic rather than Oligocene–Miocene oils (Chung et al., 1992) (Figure 5). The plot location for these oils and their calculated canonical variables (CV) indicate mainly marine source rock organic matter. These six oils account for only about 2% of the estimated ultimate recovery in the area.

Gas Geochemistry of Indonesian Basins

Significant discoveries of large to giant gas fields in Indonesia since 1990's (mainly in Eastern Indonesia and deep-water Makassar Straits) have built strong growth gas reserves in Indonesia to compensate the progressive depletion of the existing mature oil fields. This has caused a significant shift from oil to gas production. In accordance with this, understanding of the origin, distribution, and habitat of natural gases is important for a continued gas exploration.

Satyana et al. (2007) published for the first time the regional geochemistry study of natural gases in Indonesian basins based on the data from around 350 gas occurrences distributed in various Indonesian sedimentary basins. Based on molecular composition and isotope data, both thermogenic and biogenic (bacterial) gas types can be recognized in Indonesia (Figures 6-8). Mixing between the two types is also commonly observed. The thermogenic gases are characterized by a normalized methane concentration of less than 95 % and carbon isotope ratios ($\delta^{13}C_{CH4}$) heavier (more positive) than -45 ‰. The pure biogenic gases have a methane component of above 98% and $\delta^{13}C_{CH4}$ values lighter (more negative) than -60 ‰. Mixed thermogenic and biogenic gases have methane components of 95-98 % and $\delta^{13}C_{CH4}$ values in the range -45 to -60 ‰.

Thermogenic gases predominate in most Indonesia sedimentary basins and can be found in Sumatra, Natuna, Java, Kalimantan, Makassar Straits, Sulawesi, Papua, and Timor-Arafura. Genetically speaking, the gases originate from both primary generation of gas-prone kerogen and secondary generation from oil cracking. The biogenic gases are found mainly in the fore-arc basins west of Sumatra, in the East Java Basin, and in the foredeep area of the Sorong Fault Zone in northern Papua (Figure 8). The detailed geochemical descriptions of gas in each region of Indonesia proposed by Satyana et al. (2007), is summarized below.

Gas fields of Sumatra

Gas deposits in Sumatra have been found in the North, Central and South Sumatran back-arc basins, in the fore-arc basins of Meulaboh, Sibolga, Mentawai and Bengkulu, and in the intra-arc Ombilin Basin (Figure 8). The significant gas fields of Sumatra are discussed here.

The Arun gas field, in the northern part of the North Sumatra Basin, is reservoired in the Early Miocene reef of the Peutu Formation. Arun gas has 84.1 mol % CH_4 (C_{2+} of 15.9 %) and $\delta 13C_{CH4}$ value of -41 ‰, confirming its thermogenic origin. CO_2 content of the gas is up to 13.76 % and it contains 50-100 ppm H_2S. The sources for the Peutu gases are considered mainly to be the latest Oligocene Bampo shales or limestones.

Gas accumulations in the southern part of the North Sumatra Basin occur in the Rantau area (Kuala Simpang Barat, Kuala Simpang Timur and Bukit Tiram fields) and Aru to Langkat/Medan area (Paluh Tabuhan, Paluh Tabuhan Timur, Gebang, Securai, Pantai Pakam Timur and Wampu fields). The reservoirs are the Mio-Pliocene Keutapang Formation, Middle Miocene Middle Baong Sandstones (MBS), and the Lower Miocene Belumai Formation. Isotopic and compositional data suggest that all gases have a thermogenic origin ($\delta^{13}C_{CH4}$ -44.94 to -33.74 ‰). The Rantau gas complex contains non-associated dry gas generated at higher thermal maturity from Tamiang Deep kitchen, than the gases at Aru-Langkat which are associated with oil and condensate generated from Gebang Low.

Large quantities of natural gas have been discovered in South Sumatra Basin since the early 1990s. Significant discoveries are Gelam, Dayung, Sumpal, Betara, North Betara, NE Betara, Gemah, Geragai, North Geragai, Rayun, Suban, Pulau Gading, and Sungai Kenawang fields. The gases are reservoired in Gumai sandstones, Baturaja carbonates, Talang Akar sandstones, and fractured Basement. The sources of gas are considered to be the Lemat and Talang Akar shales. Based on compositional analysis and carbon-13 and deuterium isotopes, the gases are thermogenic. The gases are generally wet with CH_4 content of 59-95 %. Values of $\delta 13C_{CH4}$ and δD_{CH4} of these fields, -47.8 to -31.0 ‰ and -228 to -129 ‰, respectively, confirm that the gases are thermogenic in origin and condensate-associated.

Gas fields of Natuna

Gases from Natuna discussed here are gas fields of Buntal, Tembang, Belanak, Hiu-Kerisi and North Belut (West Natuna Basin), and from Natuna D-Alpha ("L" structure) (East Natuna Basin) (Figure 8).

In the West Natuna Basin, the majority of gas discoveries have been made in post-rift to syn-inversion sequences (Gabus/Udang to Arang Formations). The main source facies are the older syn-rift sediments (Benua and Lama Formations) which include lacustrine shales and coals, and stacked fan-delta shales. The coals and shales developed in the Arang Formation are commonly oil and gas prone. Most of the gases have 70 to 90 % CH_4 content with most $\delta 13C_{CH4}$ values between -31 and -39.6 ‰, confirming their thermogenic origin. However, some mixing with biogenic gas is found in some fields such as Buntal and Tembang with $\delta^{13}C_{CH4}$ value of -50.29 ‰ and δD_{CH4} of -232 ‰. The δD_{CH4} ratio is indicative that the majority of the methane was generated at a level of maturity at which oil may be also expected to be generated.

The East Natuna Basin is well known for hosting one of the world's largest gas fields, the Natuna D-Alpha ("L" structure) gas field, with an estimated 222 TCF gas in place of which 71 % is carbon dioxide. The gas is trapped in an isolated carbonate buildup in the upper part of the thick, Middle to Late Miocene Terumbu carbonates. The $\delta_{13}C_{CH4}$ value (-31 ‰) indicates a thermogenic origin from high maturity source rocks (~2.4 %Ro VRE). The source rocks for the hydrocarbon gas are believed to be the coals and shales within the Gabus and Arang Formations. Extensive testing of the wells within this structure showed a CO_2 content ranging from 67 % near the top of the reservoir to about 82 % near the base. There is no published $\delta_{13}C_{CO2}$ data to assess the origin of the CO_2, but based on the high concentration and the geologic setting of this field, it is speculated that the CO_2 has an inorganic origin (thermal degradation of carbonates or from mantle de-gassing). Cooper et al. (1997) considered the CO_2 was introduced by thermal degradation of carbonate. No H_2S content is reported from the gas field.

Gas fields of Java

The commercially significant gas fields of Java are found in the West Java and East Java Basins. The gas fields are distributed both onshore and offshore (Figure 8).

Gases derived from both thermogenic and bacterial (biogenic) petroleum systems occur in the West Java Basin. The gas in deeper reservoirs is primarily of thermogenic origin (Arjuna, Bojongraong, Cemara, Cemara Selatan, Cilamaya Timur, Gantar, Haurgeulis, Kandanghaur, Pamanukan, and Sukatani). The vast majority of gases from the Early to Middle Miocene Main and Massive members of the Upper Cibulakan Formation and deeper reservoirs (Baturaja carbonates and Talang Akar sandstones) have geochemical characteristics of gas generated in association with oil, or gas that was formed from oil-prone source rocks that have entered the gas window. Primary source rocks for these thermogenic gases are the fluvio-deltaic coals and shales and marginal marine shales of the Oligocene Upper Talang Akar Formation which were deposited during the post-rift sag period. In the shallow Parigi reservoirs, biogenic, thermogenic and mixed gases occur. The biogenic gases are derived locally from the fine grained intervals of the Parigi and Cisubuh Formation. The carbonate buildups of the Parigi Formation and the Pre-Parigi Member of the Upper Cibulakan Formation are known to contain large quantities of gas. The gas is dry (average 98.65 vol. % methane) and $\delta_{13}C_{CH4}$ values between -51.5 and -46.9 ‰ interpreted to be mixed thermogenic gas (with insignificant amounts of C_{2+} and CO_2).

In East Java Basin, the thermogenic gas accumulations are widely distributed across the basin. Examples of fields with thermogenic gases are Suci, Pagerungan, West Kangean, BD, Mudi, Sukowati, Banyu Urip, Kedung Tuban, Rembang, KE 5, KE 40, KE 23, Bukit Tua, Jenggolo, and Payang fields. The fields are reservoired in Eocene to Early Miocene carbonates and sandstones. These fields occur both as non-associated and associated gas. Condensates are generally produced from these fields in addition to gas. Biogenic gases occur in two belts in the East Java Basin. They are the South Madura Belt (Maleo, MDA, Terang, Sirasun and other smaller fields) and the Muriah-Bawean Belt (centered on the Kepodang Field). The main reservoirs in the South Madura Belt are Early Pliocene Mundu and Paciran sands and carbonates whereas in Kepodang, the main reservoirs are sandstones of the Middle Miocene Tawun Formation. The biogenic gases in these reservoirs are interpreted to be sourced from coeval shales and coals.

Gas fields of Kalimantan

The gas fields in the Mahakam Delta of East Kalimantan make up the largest commercial gas province in Indonesia (Figure 8). Ultimate recoverable reserves (proven and probable) are estimated as 47 TCF and 4 Bbbl oil.

Badak, in 1972, was the first significant gas discovery with reserves in excess of 6 TCF and 55 MMbbl condensate and oil. Giant discoveries were also made in the offshore areas at Tunu and NW Peciko (>22 TCF gas in place). Production occurs from numerous sandstones deposited in Middle Miocene to Pliocene fluvio-deltaic systems. The gases from Badak and Nilam have a thermogenic origin. The normalized methane content ranges from 86.1 to 92.8 %. The stable isotope values are $\delta^{13}C_{CH4}$ -40.23 ‰, δD_{CH4} -190 ‰ and Nilam ($\delta^{13}C_{CH4}$ -30.12 to - 29.84 ‰, δD_{CH4} -114 to -116 ‰) are isotopically heavy and confirm the thermogenic origin of the gases. The source rock is interpreted to be at relatively high maturity (1.4 to 2.4 % Ro VRE). The offshore gas fields of Tambora, Tunu, NW Peciko, Sisi, and Nubi have a mostly thermogenic origin but some mixing with biogenic gas are observed. The methane proportion ranges from 80.7% to 97.1% and typically decreases downwards in the stacked reservoir sections. This trend is consistent with the methane and deuterium stable isotope values which become isotopically lighter in shallower reservoirs. Values of $\delta_{13}C_{CH4}$ range from -55.19 to -35.18 ‰ but mostly fall between -44 to -49 ‰. The range of δD_{CH4} is -195 to -144 ‰, with typical values between -170 to -185 ‰. The source of the Mahakam Delta gases

is the thick deltaic succession rich in land plant derived organic matter. The humic source material is concentrated in organic shales and coal beds associated with the fluvial deltaic plain facies and in shales of the tidal delta plain and delta front. Geochemical evidence suggests that the thermal transformation of coaly kerogens in the Mahakam Delta has generated oils
and natural gases.

Gas fields of the Makassar Straits

Intensive deep-water exploration in Indonesia occurred in the Makassar Straits since the early of 1990's and has resulted in the discovery of large gas fields in the areas outboard of the Mahakam delta (such as: Gendalo, Gehem, and Gula) (Figure 8). Increasingly heavier gases and higher condensate yields are typically found in deeper reservoirs although localized reversal of these trends do exist. Waxy, low GOR oils are found in limited quantities in the deep Middle Miocene reservoirs below the gases. The gases of Gendalo, Gehem, and Gula fields are mostly sweet with low volumes of impurities. A majority of the gases in the deep-water Makassar Strait have $\delta_{13}C_{CH4}$ values in the range -52 to -28 ‰. Coupled with the high gas wetness, these values are characteristic of thermogenic origin at "oil window" temperatures. Presumably, the gases were sourced by type III kerogens, as supported by the biomarkers in the associated condensates. The thermogenic gases are predominantly reservoired in upper Miocene turbiditic sands. A subordinate number of gases exhibit characteristics of biogenic-thermogenic mixing with $\delta^{13}C_{CH4}$ values of -65 to -55 ‰. These gases are mostly reservoired in the shallow Pliocene sands and typically have low condensate yields. Two gases from Pliocene reservoirs are almost pure methane and have $\delta^{13}C_{CH4}$ values of ca -75 ‰, indicating a biogenic origin.

Gas fields of Sulawesi

Gas fields of Sulawesi are from Kampung Baru, Walanga, Sampi-Sampi, Bonge gas fields in the Sengkang Basin, South Sulawesi and from Mantawa, Minahaki, Matindok, Senoro, Anoa, Donggi, Sukamaju, Kampung Bali, and Maleo Raja gas fields in the Banggai Basin, East Sulawesi (Figure 8).

The Kampung Baru, Walanga, Sampi-Sampi, and Bonge gas fields occur in the Late Miocene Tacipi reefs of the Sengkang Basin, South Sulawesi and contain about 630 bcf gas in total. The gases are relatively dry with CH_4 content of 96-100 %, indicating a mixed thermogenic and biogenic origin. A possible source interval is speculated to be the lateral argillaceous equivalent of the Tacipi Formation, which could contain gas prone organic matter, deposited in deeper western part of the Sengkang Basin. The absence of isotope data makes further interpretation impossible.

The gases discovered in onshore eastern Sulawesi wells appear to be complex, with components derived from biogenic origin (Mantawa and Minahaki gases, $\delta^{13}C_{CH4}$ values of -59 ‰ to -62 ‰) and thermogenic origin (Sukamaju, Kampung Bali, Maleo Raja, Senoro, Matindok gases, $\delta_{13}C_{CH4}$ values of -53 to -32 ‰). Based on carbon isotope data, there is a significant variation in the maturity of the thermogenic source rocks from Sukamaju (least mature) to Matindok (most mature). Compositional data confirm the thermogenic origin with CH_4 content of 86.5-96.5 %. The Senoro gas field is a large gas field with a total estimated reserve of 3.7 TCF gas and 65 MMbbl condensate. There are two potential source rocks sequences recognized in East Sulawesi: Jurassic marine shales and Miocene marine shales, coals, and marls. Geochemical analyses to date indicate that oil seeps and all of the oils and gas tested from the area are most likely related genetically to shales and coals within the early to middle Miocene Tomori Formation. (Satyana and Zaitun, 2016). This study reveals no significant evidence of petroleum contribution from Pre-Cenozoic source rocks occur in the Banggai Basin. The proven sources are Early Miocene Tomori carbonates and shaly carbonates and Middle Miocene Matindok shales and calcareous shales. The gases are products of both thermal cracking of oils and primary gas generation from Miocene source rocks with humic kerogens. However, gas seepages in the Sula Basin to the east of Banggai Basin are geochemically related to generation from Pre-Cenozoic source rocks deposited in graben areas of offshore Taliabu-Mangole Shelf.

Gas fields of Papua

Significant gas fields in Papua are found in the Bintuni Basin, the Bird's Head of Papua, containing six gas fields that make up the Tangguh LNG Project (Figure 8). Total reserve potential is estimated at 24 TCF. The six gas fields are Vorwata, Wiriagar Deep, Ubadari, Roabiba, Ofaweri, and Wos. Permo-Jurassic source beds in the Bintuni Basin kitchen have been geochemically typed as sourcing the Roabiba/Ofaweri/Wos late maturity dry gas (Perkins and Livsey, 1993). Gases of the Wiriagar Deep and Vorwata fields are representative of the Tangguh LNG gas fields. The gases are relatively dry comprising mostly methane with subordinate wet gas components. The gases are generated from a source interval containing mostly humic organic matter. Chemical composition and carbon isotope data show the gases are thermogenic in origin. The composition of the gases is dominated by hydrocarbon gases (72-97 %) of which methane is the most abundant (78-97 %). Heavier hydrocarbon gases are present in sufficient quantities to indicate a thermogenic origin of the gases. Methane carbon isotope signatures of -34 ‰ to -28.0 ‰ confirm a thermogenic source for these gases and that maturity levels were high. The Wiriagar Deep gas plots as a non-associated, relatively dry gas derived from humic organic material. Deuterium isotope analysis performed on the methane fractions produced comparable isotopic values (-119 ‰ and -122 ‰). While these data confirm a thermogenic origin, the extremely heavy nature of the results ($\delta^{13}C_{CH4}$ values of -28.2 to -28 ‰) suggests generation within the dry gas window. A possible explanation would be that very dry gas (>99 vol. % methane) mixed with lower maturity wet gas during secondary migration.

Gas fields of Timor-Arafura Sea

The giant Abadi gas field (total reserve potential estimated at 18 tcf) is representative of the Timor-Arafura Sea area. (Figure 8). Several large gas discoveries have been reported also to occur southward across the border with Australia (e.g. Evans Shoal and Barossa). Abadi is located in 400-800 m water depth on the continental slope where Australia is being underthrusted beneath the Timor-Tanimbar Trough to the north. The trap is a large tilted fault block bounded to the east and south by the Malita-Calder Graben. The accumulation contains a significant gas column, approximately 130-140 m, reservoired in the shallow marine Middle Jurassic Plover Formation. The Abadi gas comprises predominantly methane (c.84-88vol.%, normalized) and is moderately wet. Condensate/gas ratios are reported to range from 10.4 to 19.2 bbl/MMscf. Stable carbon isotope ($\delta^{13}C_{CH4}$ -37.06 to -34.76 ‰) and deuterium (δD_{CH4} > -150 to -157 ‰) data suggest that the gas has a thermogenic origin and was generated from source rocks at an advanced maturity level (1.3-1.8 %Ro). The condensate content and the isotope values for ethane and propane fractions are consistent with gas generated at a late mature stage.

Non-hydrocarbon gases of CO_2 and H_2S

Within the Australasian region, CO_2 is the major contaminant, and in some cases it is the dominant gas species in an accumulation. For example, in the Natuna D Alpha gas field, an estimated 157 TCF of CO_2 is present, representing 71% of the gas in-place. Carbon dioxide may be introduced into a petroleum system through a number of means. These include derivation from an organic source, the destruction of carbonate minerals through catalysis with clays, hydrolysis, high temperature processes, and mantle or volcanic de-gassing. The stable carbon isotopic composition of CO_2 is the primary means of determining the mode of CO_2 formation. Isotopically light CO_2 ($\delta^{13}C_{CO2}$ < -10 ‰) is derived from organic matter through maturation. $\delta^{13}C_{CO2}$ values between -4 and -7 ‰ are typically associated with mantle de-gassing. Isotope ratios associated with carbonate destruction partially overlap those of mantle de-gassing (–10 and 2 ‰). Multiple formation processes may be active in a basin.

Hydrogen sulfide (H_2S) is the deadliest gas produced in large quantities in nature and is a serious occupational hazard in the oil and gas industry. Hydrogen sulfide in gas reservoirs has two major sources: the thermal decomposition of high-sulfur oils and thermochemical sulfate reduction (TSR) in pore waters.

TSR is the reaction of sulfate minerals (primarily anhydrite) and hydrocarbons (beginning at temperatures of 120-140 ºC) to form H_2S and calcium carbonate. Because anhydrite is often associated with carbonate sequences, TSR is commonly associated with deep, hot, carbonate reservoirs and/or source rocks. TSR is the most important process for formation of high-H_2S gases (>10% H_2S). Some H_2S also comes from the thermal degradation of kerogen and coal.

High concentrations (>50 %) of CO_2 occur in North and South Sumatra, East Natuna, and the onshore Java basins. Generally, values of $\delta^{13}C_{CO2}$ are isotopically heavy and indicate an inorganic origin by carbonate thermal destruction or mantle/volcanic degassing. The primary control on CO_2 content in gas fields of North Sumatra appears to be the nature of the substrate underlying the Peutu Formation. Higher CO_2 content occurs in fields where limestone or dolomite, such as in the Tampur Formation, subcrop the Peutu. shale substrates, such as in the Bampo Shale, tend to be associated with lower CO_2 fields. The association with subcropping carbonates indicates the CO_2 originates from thermal decomposition of carbonates. Analyses of carbon isotopes support this conclusion with values of $\delta^{13}C_{CO2}$ between –0.95 to -3.97 ‰. Only minute quantities of helium and hydrogen have been detected, supporting the theory that the CO_2 does not have a magmatic origin (Cooper et al., 1997).

Consequently, it is concluded that the risk of encountering high CO_2 content can be reduced by avoiding deep, hot areas where the Peutu directly overlies the Tampur Formation and/or pre-Cenozoic basement.

The distribution of CO_2 throughout the South Sumatra Basin is a key exploration risk, with the concentration ranging from 0 to 98 mole %. Suklis et al. (2004) studied the origin and distribution of CO_2 in the Corridor Block and divided the fields with CO_2 into three groups: - Group A, CO_2 < 20 mole %, $\delta^{13}CCO_2$ -8.3 to - 4.0 ‰, (Suban, Gelam fields), - Group B, CO_2 20-40 mole %, $\delta^{13}CCO_2$ -4.8 to - 0.1‰, (Dayung, Sambar, Sumpal, Rebonjaro fields), - Group C, CO_2 > 40 mole %, $\delta^{13}CCO_2$ -4.4 to -1.8 ‰, (Bungkal, Bungin, Rayun, Bentayan, Puyuh fields). Based on these values, the CO_2 of the three groups may come from either mantle degassing (-4 to -7 ‰) or carbonate decomposition (–10 to 2 ‰). There may also be a small CO_2 contribution from maturation of organic matter (-25 to -10 ‰) to the Group A gases. In general, the CO_2 content increases with present-day reservoir temperature and reservoirs with temperature > 165 ºC have a higher risk of CO_2 content > 40 mole %. Granite and metamorphic quartzite reservoirs have lower CO_2 content than schist, phyllite, argillite, limestone and marble reservoirs.

In West Java Basin, the amount of CO_2 is higher (over 50 %) in some onshore and coastal regions that have received gas derived from high temperature metamorphism of carbonate minerals or volcanic degassing. For example, the Haurgeulis, Sukatani, Pamanukan, and Cikarang fields are mostly composed of CO_2 (74-92 % of the total gas). Gas from the Baturaja Formation in Pamanukan-2 well has a $^3He/^4He$ value of 4.002RA indicating a contribution from mantle de-gassing (Cooper et al., 1997). Non-hydrocarbon gases in East Java gas fields consist mainly of CO_2. Onshore, high CO_2 values are seen in the Oligo-Miocene Kujung-Tuban carbonates in the Cepu area. Examples are Kedung Tuban (24.86 %), Sukowati (40.74 %), Banyu Urip (47 %), Rembang (45-65 %) and Gabus (78.57 %). Some gas seeps in the Surabaya area also show high CO_2 content (Deling, 38.72 %; Sepat Kaliasin, 35.59 %). Offshore, high CO_2 content (74 to 91 %) occurs in several Rembang Bay wells (Kutilang-1, Nuri-1, Perkutut-1) and in the Bawean Arch discoveries, Titan-1 and Calypso-1 (75 to 85 %). Carbon isotope data of CO_2 are available from Kedung Tuban ($\delta^{13}CCO_2$ 0.52-1.62 ‰), Rembang (- 5.17 to 0.03 ‰) and Gabus (-4.85 ‰). These values are consistent with CO_2 formation by thermal destruction of carbonates.

H_2S is moderate to high (500 to > 10,000 ppm) in some gas fields in North Sumatra, South Sumatra, East Java, East Sulawesi and Salawati Basins. Carbonate buildups of the Early Miocene Belumai Formation (a time equivalent of the Peutu Formation) occurring in the offshore North Sumatra Basin (NSB area) to the north of Arun has H_2S (10,000-15,000 ppm). The Peutu reservoirs mostly contain only small amounts of H_2S (24 ppm to a maximum of 2000 ppm at Alur Siwah. In South Sumatra, H_2S is known from gas fields of Musi (22,000 ppm) and Tanjung Miring (264,000 ppm – the highest recorded in Indonesia). H_2S occurs in some carbonate reservoirs in the East Java Basin but generally the concentration is less than 1000 ppm. However, BD carbonate reef in the Madura Strait is reported to contain 4500 ppm H_2S. In East Sulawesi, the gas fields of Anoa, Donggi, Maleo Raja, and Senoro contain 300-800 ppm H_2S. In Salawati Basin, Papua, the Lao-Lao gas field and the gas reservoir in Walio Field have 500 to 13,300 ppm H_2S. All occurrences of high H_2S content can be known from isotope S_{34}, but we do not have such data in Indonesian gas fields with high H_2S content. Most of the high H_2S content are interpreted to relate to thermo-chemical sulfate reduction (TSR) of deep burial of carbonate sequences.

Some Current Geochemical Issues

Recent geochemical analyses, reinterpretation, and studies related have resulted in new information and understanding at the base of new conceptual model that may be criticalfor petroleum system analyses, hence may effect future exploration efforts. The following highlight some of those points:

a. Paleogene sourced - oil seeps in Java's volcanic areas

Numerous oil and gas seeps occur on Java Island where Neogene to Recent volcaniclastic sediments are at the surface. Before good geologic science was applied, people believed that oil was derived from magmatism and volcanism (inorganic theory). The concept is now that volcaniclastic sediments buried the source rocks into the depths where oil and gas were generated, and migrated to surface as seeps.

The seeps occur in three areas of Java Island: Banten Block, Majalengka-Banyumas, and North Serayu (Satyana, 2015b). Some of the oil seeps were geochemically characterized and oil to expected source correlation was conducted (Figure 9). The presence of oil seeps at Banten block may indicate that the source has been mature generating petroleum. The primary sources are Eocene-Oligocene Bayah shales and coals. Paleogene local deeps/half grabens acted as kitchen areas within the block. Field data on vitrinite reflectance shows that the Bayah Formation has entered into the oil window with Ro of 0.6-1.5 %. Migration has taken place both laterally through carrier beds and vertically through faults. In Majalengka-Banyumas area, the presence of oil seeps is important. The first exploration well of Indonesia (Maja-1 well, drilled in 1871, oil discovery) was located in this area. The Maja oil was geochemically analyzed and correlated to a source from Early Miocene shale equivalent to Talang Akar Formation. In the North Serayu area, northern Central Java, oil seeps occur among volcanic covers. The seepages occur in the areas of Karangkobar, Bawang and Subah, Klantung and Sodjomerto, Kaliwaru, West of Mt. Ungaran (many seepages), and East of Mt. Ungaran. Exploratory drillings carried out by Dutch oil companies since the early 1900s near the seepages and had no success. Drilling in Klantung and Sodjomerto later was successful and the Cipluk Field was discovered. Cipluk Field (now abandoned) is formed by a faulted anticline of Late Miocene Banyak volcaniclastic sandstones. Oil seeps in this area have been geochemically analyzed and interpreted to be sourced by sediments equivalent in age and facies with Talang Akar Formation in West Java Basin. Oil seep located more to the south at Karangkobar area, and condensate tested by Jati-1 well in Banyumas area correlated to middle Eocene Karangsambung shales.

Geochemical characteristics of oil seeps and their correlation to expected sources showing that the sources of the seeps were Paleogene fluvio-deltaic sources. Neogene volcanic covers provide burial sediments for source maturation. Oil and gas seeps in volcanic areas of Java show the presence of active petroleum systems underneath the volcanic covers. This indicates hydrocarbon prospectivity of Java Island under volcanic covers (sub-volcanic play) that has been so far unexplored.

However, volcaniclastic covers are notorious for causing poor seismic data quality, making subsurface imaging difficult. This will certainly challenge exploration of the subvolcanic petroleum play of Java.

b. Marine Mesozoic oil in East Java Basin

Recent study of Mesozoic tectonic reconstruction of southeastern and eastern margins of Sundaland (Satyana, 2014) and recent geochemical analyses on some oils in Kangean area, East Java Basin (Sutanto et al., 2015, 2016; Musu and Sutanto, 2015) led to the discovery that Mesozoic marine source rocks generated oils and migrated into Eocene carbonate reservoir in Sepanjang field. This resulted in the suggestion that a proven Pre-Cenozoic petroleum system exists the East Java Basin (Satyana, 2016a).

Satyana (2014) argued a tectonic reconstruction that in mid-Cretaceous time there was Australia/Gondwana-derived microcontinent/s and its/their sedimentary covers, which collided against the margin of Southeast and East Sundaland. Derivation of the microcontinents from NW/West Australia opens the possibility for Mesozoic sections deposited in rifted structures formed within the microcontinents. The equivalent sections in the present-day NW Shelf of Australia are very prolific as petroleum sources and reservoirs, as testified by the many oil and gas fields which have been discovered in Mesozoic sections. The presence of similar Mesozoic sections in the microcontinents colliding southeast and East Sundaland potentially provide a similar opportunity for petroleum prospectivity in Mesozoic targets of East Java, South Makassar, and East Java forearc areas. This argument is supported by deep seismic sections in offshore areas of South Makassar, East Java Sea, and South East Java Forearc, which show a considerable pre-Cenozoic sedimentary section of probable Mesozoic and Paleozoic age overlying the microcontinents.

East Java oils are typically waxy, indicating that they were derived from non-marine source rocks (Satyana and Purwaningsih, 2003). The dominant peaks of prystane and phytane, mostly > 4.0 also indicate that the hydrocarbons were derived from sub-oxic and oxic fluvio-deltaic source rocks. Moreover, the ternary diagram of m/z 217 sterane C_{27}-C_{28}-C_{29} also showed that the hydrocarbons derived from sources with a predominant terrestrial organic origin. Oleanane index of the oils > 0.20, mostly between 0.6-0.8, show that the source rocks were Cenozoic and fluvio-deltaic facies. Eocene Ngimbang coaly shales are the proven source rocks for the East Java Basin oils and most of the gases.

Recent geochemical analyses conducted on the oils of the Sepanjang oil field found very anomalous oil characteristics, diverting from the general characteristics of the East Java oils (Sutanto et al., 2015; Musu and Sutanto, 2015, Sutanto et al., 2016, Satyana, 2016a). Based on biomarkers and deuterium isotopes, the Sepanjang oils show stronger marine influence (Figure 10) and reducing conditions although mixed with general characteristics of oils from terrestrial and oxidizing source rocks. The oils also show very low oleanane and sterane indexes, indicating that the source of oils could be pre-Cenozoic (possibly Lower Cretaceous) in age (Figure 11). The presence of *Alisporites sp*., an index taxa of the Lower Cretaceous in the sediments analyzed, is another strong indication that there is a Cretaceous source in the area.

Pristane and phytane ratio (Pr/Ph) of Sepanjang oils range from 1.5 to 2.5. Supported by Pr/n-C_{17} ranging from 0.1 to 0.3, and cross plots of Pr/n-C17 versus Pr/n-C18, it suggest the Sepanjang oils to have strong marine origin. Dominant C_{27} composition and high diasterane/sterane of Sepanjang oils indicate marine shaly source rocks (Figure 12). Ternary diagram using C_{27}/C_{28}/C_{29} sterane distribution shows that Sepanjang oils were derived from sources with estuarine to open marine facies. This is different to most East Java oils which were sourced by terrestrial source facies (Satyana and Purwaningsih, 2003). The origin of the Sepanjang oils was also investigated using deuterium isotope for all n-alkanes of oils (Musu and Sutanto, 2015). δD values of n-alkanes in Sepanjang oils Samples revealed the hydrocarbon originated from marine source rock (marine shale), the values of δD mostly in between -100 to -150 ppt, indicating marine oils (> -200 ppt for marine, terrestrial will be < -200 ppt). Whereas most East Java oils are around -300 ppt (terrestrial). The source lithology is expected from C_{29} norhopane/C_{30} hopane m/z 191 peak ratios: less than 1 for shale source and above 1 for carbonate source. The Sepanjang oils show < 1 C_{29} norhopane/C_{30} hopane, showing shaly source.

The age of the Sepanjang oil is investigated using age-diagnostic biomarkers of olenane, sterane, and triaromatic dino-steroid (TDS). Oleanane index (Oleanane/Oleanane+C_{30}hopane) is used to determine biostratigraphic age of hydrocarbon or sediments. An Oleanane index of more than 20% is diagnostic of Cenozoic or younger source rocks and related oils (Moldowan et al., 1994). Sepanjang oils show very low abundance of oleanane with an oleanane index of only 9.2 - 9.5 %, far less than the oleanane index of East Java oils which are mostly around 60 - 80 % (Satyana and Purwaningsih, 2003). C_{28}/C_{29} sterane can also be used for biostratigraphic age determination for crude oils from marine source rock with little or no terrigenous organic matter input. A ratio of sterane index that is less than 0.5 suggests Lower Paleozoic and older oils, whilst values between 0.47 - 0.7 are considered to show Upper Paleozoic to Lower Jurassic oils, and greater than 0.7 for Upper Jurassic to Miocene oils (Grantham and Wakefield, 1988). GCMS reveals that Sepanjang oils are a mixture from terrestrial to marine environments with sterane index ranging from 0.5 to 0.7. Recent analyses conducted by Sutanto et al. (2016) to establish the age of source rocks of Sepanjang oils involved applying biomarkers attained from the aromatic fraction of three oil samples from the Sepanjang field; namely Triaromatic Dinosteroid (TDS). Triaromatic dinosteroids are organic geochemicals derived from dinosterols, compounds known in modern organisms to be the nearly exclusive widely occurring products of marine dinoflagellates (Moldowan et al., 1996). They have been detected in Precambrian to Cenozoic rock samples, but are generally abundant in Mesozoic samples (Late Triassic through Cretaceous marine source rocks). The abundant presence of the triaromatic dinosteroid biomarker in oil shows a marine source of Mesozoic age. Oils from Sepanjang wells were tested for their aromatic fraction TDS, and the results show a high number (above 0.80-0.84 or above 80 %) of Triaromatic Dinosteroid Index (TDSI) for all samples which may highly correlate to the Mesozoic age.

Various geochemical analysis on Sepanjang oils, including bulk properties, saturate and aromatic biomarkers (triterpane, oleanane, sterane, triaromatic dinosteroid), carbon and deuterium isotopes, may suggest that the Sepanjang oils were sourced by marine Mesozoic shales. Based on biostratigraphy and tectonic reconstruction, the source rocks should be Lower Cretaceous marine shales. The Sepanjang oil field is located right on the Kemirian Terrace which is considered here to be the southern margin of the Paternoster-Kangean microcontinent. The margin is also the site of the major Sepanjang strike-slip fault and a possible charging scenario would involve the fault system to be used as a conduit. The hydrocarbons expelled from the Lower Cretaceous source beds would migrate vertically through the Sepanjang Fault into the Eocene Ngimbang fractured carbonate reservoirs of the Sepanjang field.

c. Cenozoic and Pre-Cenozoic oil and gas of Banggai-Sula area

Banggai Basin with its productive Miocene objectives in Eastern Sulawesi has positioned as foreland basin since Mio-Pliocene time, when the collision of Banggai-Sula microcontinent and East Sulawesi Ophiolite Belt took place. To the east of the basin there is Sula (Taliabu-Mangole) platform preserving Pre-Cenozoic grabens (Sula Basin). Before the collision, the Banggai-Sula microcontinent drifted to its present area bringing syn-rift Jurassic passive margin siliciclastic sediments and Cretaceous to Miocene syn-drifting carbonates. All of these rocks have been potential to be elements (sources, reservoirs, seals, overburdens) and processes (trap formation, petroleum generation-migration) of petroleum system. Collision of the microcontinent significantly affected all processes of petroleum system. Recent paper by Satyana and Zaitun (2016) discussed the origin of oil and gas in this area, to establish the roles between Cenozoic and pre-Cenozoic source rocks.

The study reveals that all oils in the Banggai Basin are sourced by Early Miocene Tomori carbonates and shaly carbonates (resulting in type "A" oils) and Middle Miocene Matindok shales and calcareous shales (resulting in type "B" oils). As for the gases, isotope data show that gases in the Banggai Basin are products of both thermal cracking of oils and primary gas generation from Miocene source rocks with humic kerogens. No significant evidence of petroleum contribution from Pre-Cenozoic source rocks in the Banggai Basin, considered due to overmaturity issue after the collision. However, gas seepages in the Sula Basin are geochemically related to generation from Pre-Cenozoic source rocks deposited in graben areas of offshore Taliabu-Mangole Shelf. This study will provide new directions for further exploration in the Banggai-Sula area, targeting both Cenozoic and Pre-Cenozoic objectives (Figure 12).

d. Neogene proven source rocks of Buton area

Buton Island, SE Sulawesi, has been famous for its asphalt deposits mined since 1920's and it is the only natural asphalt deposits mined in Indonesia. All geochemical data indicate that the asphalt deposits are biodegraded crude oils derived from marine, type II kerogen. Good to excellent correlations were obtained between asphalt deposits and calcareous shales and bituminous limestones of Triassic Winto Formation. Severe deformation due to collision of Buton microcontinent with SE Sulawesi eroded cap rocks of the traps, causing meteoric water flushing and biodegradation of the oils, leading to asphalt deposits. Occurrences of large asphalt deposits and numerous oil seeps show that petroleum system of Buton area is working. However, exploration efforts in this area have been so far disappointing. The main risks include complicated structures and absence of cap rocks. Poor quality seismic data hinder detailed imaging of structures. All exploration wells drilled to date have failed to penetrate the main target of Cretaceous Tobelo limestones. Targeting the Mesozoic targets seems to be very difficult before significant improvement of seismic imaging is obtained.

Targeting shallow targets with no complicated structures can become alternatives. Miocene reservoirs of the coarse clastic facies of Tondo Formation are the targets. This facies is comprised of stacked sands and conglomerates as well as carbonates deposited as deltaic, shallow marine to deep marine turbidite fans. Total thickness of individual reservoirs range from 5 meters to over 100 meters. The reservoir potential varies from poor to good. Porosities range from 8% to over 25% and average 19%. Maximum measured vertical and horizontal permeability is 172 mD. All evidence suggest that early migration of hydrocarbons into the reservoirs is critical in inhibiting diagenesis and retaining primary porosity. Additional potential reservoirs include interbedded pinnacle reefs and platform carbonates of the Pliocene Sampolakosa Formation, Pliocene / Pleistocene Wapulaka Formation.

The shallow targets could be easier charged also by generated hydrocarbons from shallow source rocks. Benteng-1 well drilled by Japex Buton in 2012 found oil in Miocene Tondo fractured limestone (Satyana et al., 2013). The main target of Late Cretaceous Tobelo carbonate was not yet penetrated due to complicated structure. Oil extracted from SWC sample at depth 731 m of Benteng-1 well indicates generation from Tondo marine shales/calcareous shales as shown by presence of high oleanane content, tricyclic terpanes, high 29-norhopane to 30- hopane and ratio of Ts/Tm < 1.0 (Figure 13). This well and one oil seep called Nunu seep to the east of Buton Strait (west Buton), moderately degraded oil, containing oleanane showing that in Buton area there is another proven generating source rocks, namely Miocene Tondo source rocks. Tondo Formation shales and mudstones are good source rocks, sometimes show excellent potential (TOC ranges 6-10.8 %).

e. Neogene oil seep of northern Papua

North Papua Basin is a forearc basin located in the northern part of Papua, Indonesia. The basin has been categorized as frontier basin due to limited exploration activities. There have been 11 wells drilled since 1950, including 5 dry wells, 1 gas discovery, 1 well with oil and gas show. 4 wells were plugged and abandoned due to mechanical trouble. In addition to this, there is the famous oil seep of the Teer River. The presence of gas discovery well and oil seep shows active petroleum system in this area.

The recent paper by Musu et al. (2015) presents the new results of the geochemical analyses of the oil seep (Figure 14) which imply petroleum system evaluation hence improving the area prospectivity. The oil seep has been sampled and analyzed for their biomarkers using gas chromatography (GC) and gas chromatography/mass spectrometry (GC/ MS) of saturate triterpanes m/z 191, steranes m/z 217 (Figure 14), and aromatic methyl phenanthrene (m/z 178 and m/z 192). The oil seep is minor biodegraded based on the distribution of n-alkanes. The isoprenoid pristane/phytane ratio indicates that the oil was generated from shaly to coaly source rocks deposited in oxidizing environment. High peak of oleanane from triterpanes and the appearance of bicadinanes from steranes conclude that the source rocks are Miocene in age at the oldest, from kerogen type III. Based on methyl phenanthrene distribution, the oil was generated from a maturity equivalent with Ro of 0.9.

Based on geochemical analyses and geologic setting of the North Papua Basin, the strongest candidates for the active source rocks are those within the Middle- Late Miocene Makats and/or Early Pliocene Memberamo “B” Formations. The sediments of both formations were deposited in terrestrial to transition/estuarine environments which fit with the oil characteristics.

The presence of source rocks generating oils as shown by the oil seep of the Teer River is the most important element and process of the petroleum system in this area. Other elements and processes of petroleum systems including reservoirs, seal rocks and trap formation exist in the basin based on the geologic setting but need further data and studies to resolve. These provide opportunities for petroleum exploration in North Papua Basin which so far has been under-explored.

Molecular biomarkers for regional tectonic studies of Indonesia

Biomarkers are organic chemical compounds whose structure or skeleton of carbon, hydrogen and other elements are formed by living organisms and are sufficiently stable to be recognized in crude oil or in the organic matter of ancient sediments. Biomarkers are also called molecular fossils, indicating formerly living organisms that developed in specific geologic environments.

Development of paleogeographic settings and depositional environments was driven by tectonics. Source rocks with some specific biomarkers were deposited within these depositional environments/source facies. Oils generated from organic matter of the source rocks contain biomarkers that are specific for depositional environments. Therefore, the oil biomarkers can be used to prove the existence of paleogeographic sites / depositional environments formed by tectonics. This means that oil biomarkers, indirectly, can be used to examine models of tectonics.

Recent paper by Satyana (2016b) showed three cases in Indonesia of how oil biomarkers can be used to examine tectonic models proposed previously. In western Indonesia, Paleogene rifted basins of Sumatra that were developed due to stress release of the Sumatran Fault relating to tectonic escape of post-collision India to Eurasia in Eocene time, were examined using oil biomarkers to understand the development of source facies formed during the rifting. In Central Indonesia, biomarkers from recently discovered Eocene oils in the deep Makassar Straits and oil seeps in Western Sulawesi onshore were employed to examine the model of the Makassar Straits opening. In eastern Indonesia, the Salawati Basin, undergoing tectonic reversal of its depocenter before and after the advent of the Sorong Fault tectonism in Mio- Pliocene time, was examined by oil biomarkers from fields charged by Kais/Klasafet sources that deposited in the kitchen of Sorong foredeep. On these cases, biomarkers can confirm the tectonic models proposed.

The right understanding of tectonic models is important for determining appropriate exploration strategy. Petroleum system analysis, area of priority, objectives of exploration drilling, or selection of wildcat well location can be better evaluated and to be morelikely successful based on confirmed tectonic models. Therefore, confirmed tectonic models, in this case using biomarker methods, are important.

Implications for Future Exploration

Regional petroleum geochemistry of oil families and their sources, genetic gas types and their sources, and some current geochemical issues in Indonesian sedimentary basins have been discussed. As mentioned, including geochemistry in prospect maturation improve notably exploration efficiency. Knowing precisely what the proven source is in a basin, it can help building right systematic exploration strategy of the basin.

Most of the Western Indonesian basins have been intensively explored (Satyana, 2016c), and most of the oil families and genetic gas types have been established in those basins, with a reasonable understanding of active source rocks at the orogin of those petroleum products. However, identification of new oil family is important because it shows the presence of new generating source rocks unidentified so far. The possible presence of Mesozoic oil in the East Java Basin is an example of this. It may support the opportunity to explore the entrapments of this Mesozoic oils. The presence of the Paleogene sources in Java Island generating oils that become the oil seeps among the volcanic covers show that the sources are proven and making the sub-volcanic petroleum system to be active and prospective for further exploration.

In Eastern Indonesian basins, some areas have been explored intensively for some targets such as Miocene carbonates in the Salawati and Banggai Basins or Jurassic sandstones in the Bintuni Basin and Jurassic carbonates in Seram Island (Satyana, 2016c). Some geochemical aspects of these basins/areas have been well known. However, beyond these areas or targets, the exploration efforts in Eastern Indonesia have not been intensive, therefore resulting in a relative lack of data, including for petroleum geochemistry. Nevertheless, some fields or discoveries, as well as the presence of oil and/or gas seeps, in Timor, Tanimbar, Arafura Sea, Lengguru-Central Ranges of Papua, North Papua, and South Papua, geochemically show the presence of actively generating source rocks. These phenomena are good to chase for exploration prospectivity. Source rock is the most important element of petroleum system because petroleum come from source rock – when there is no source rocks there is no petroleum although there are excellent reservoir and trap. Accordingly, the presence of oil / gas fields / discoveries / seeps in an area is very important since it reveals the presence of actively generating source rock. Petroleum geochemistry is a critical element in characterizing oil/gas and related sources. Other elements and processes of the petroleum system should obvioulsy be evaluated following this assessment until some prospects and play concepts are matured and proposed for drilling.

Satyana (2017, this convention) proposed regional play types for future exploration of Indonesia, some of which are based on studies of petroleum geochemistry discussed above. Detailed petroleum geology of each play type can be found in this publication.

CONCLUSIONS

1. Studies on regional petroleum geochemistry of Indonesian basins have been conducted over the past thirty years. This review integrates the results from those previous publications, and provides an update to include recent progresses.

2. As previous studies show, with additional data, oil families and their source rocks in Western Indonesia basins can still be categorized into three broad families: lacustrine, fluvio-deltaic and marginal-shallow marine. Basins with main lacustrine oils are Central Sumatra, Sunda-Asri, partly West Natuna, and West Sulawesi Offshore/North Makassar Straits. Basins with main fluvio-deltaic oils are South Sumatra, West Java, East Java, Barito, Kutai, and Tarakan. Basins with marginal-shallow marine oils are North Sumatra and West Sulawesi Onshore. The proven source rocks for these basins/areas are Paleogene shales, coaly shales, and marginal-shallow marine shales and carbonates. The proven source rocks of Kutai and Tarakan basins are Neogene coaly shales and coals. Most of the oils from Eastern Indonesia basins/areas are marginal-shallow marine (Salawati, Banggai, Buton, Seram, Bintuni, Timor); sourced by Neogene shales, marls, carbonates (Salawati, Banggai) or Jurassic marine shales (Bintuni), Triassic-Jurassic marine shales (Timor, Buton) or Triassic-Jurassic carbonates (Seram, Timor).

3. Based on molecular composition and isotope data, both thermogenic and biogenic (bacterial) gas types can be recognized in Indonesia. Mixing between the two types is also commonly observed. Thermogenic gases predominate in most gas provinces in Indonesia and can be found in the basins of Sumatra, Natuna, Java, Kalimantan, Makassar Straits, Sulawesi, Papua, and Timor-Arafura. The gases were resulted from both primary gas generation from gas-prone kerogen and from secondary gas generation through oil cracking. The biogenic gases are found mainly in the fore-arc basins west of Sumatra, in the East Java Basin, and in the foredeep area of the Sorong Fault Zone in northern Papua. High concentrations of non-hydrocarbon CO2 mainly occur in North and South Sumatra, East Natuna, and onshore Java. Based on the “heavy” values for δ13CCO2, most CO2 occurrences have an inorganic origin by either thermal destruction of carbonates or volcanic degassing. H2S concentrations are moderate to high (500 to >10,000 ppm) in some gas fields in North Sumatra, South Sumatra, East Java, East Sulawesi and Salawati Basins. All occurrences of high H2S relate to thermo-chemical sulfate reduction of deep, hot carbonate sequences.

4. Some current petroleum geochemistry issues are observed, they include: Paleogene oil seeps in Java's volcanic areas, marine Mesozoic oil in East Java Basin, Cenozoic oil and Pre-Cenozoic gas of Banggai-Sula area, Neogene proven source rocks of Buton area, Neogene oil seep of Northern Papua, and the application of molecular biomarkers for regional tectonic studies of Indonesia.

5. Geochemistry has significant contribution to exploration efficiency, because it shows genetic relationships between petroleum products and and their source(s). Geochemistry increases exploration efficiency by accounting for many of the variables that control the volumes of petroleum available for entrapment (charge), including source-rock quality and richness, thermal maturity, and the timing of generation-migration-accumulation relative to trap formation. Knowing precisely what the proven source is in a basin, it can help building right systematic exploration strategy of the basin.

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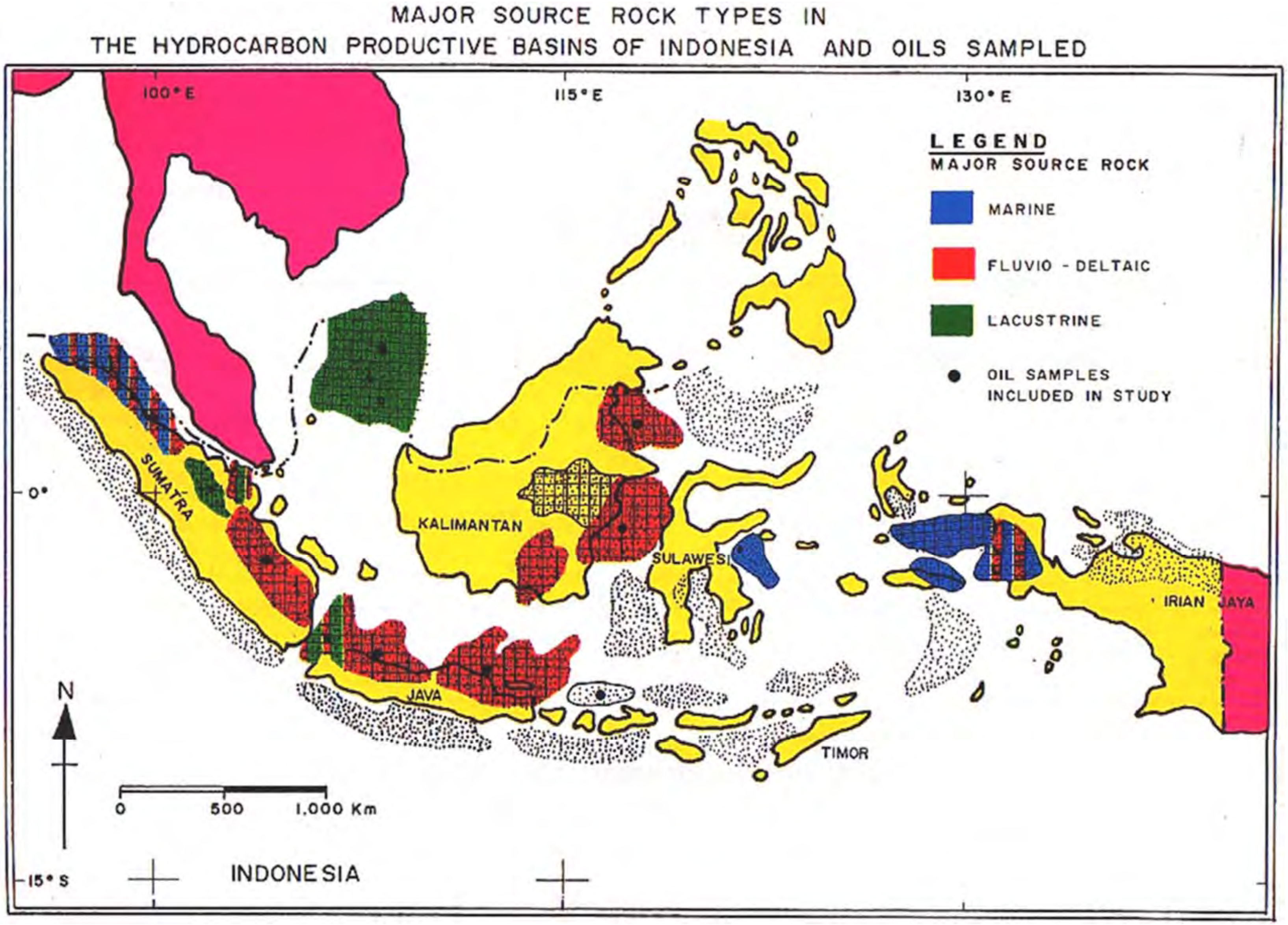


Figure 1 - Major source rock types in the hydrocarbon productive basins of Indonesia and oils sampled (Robinson, 1987).

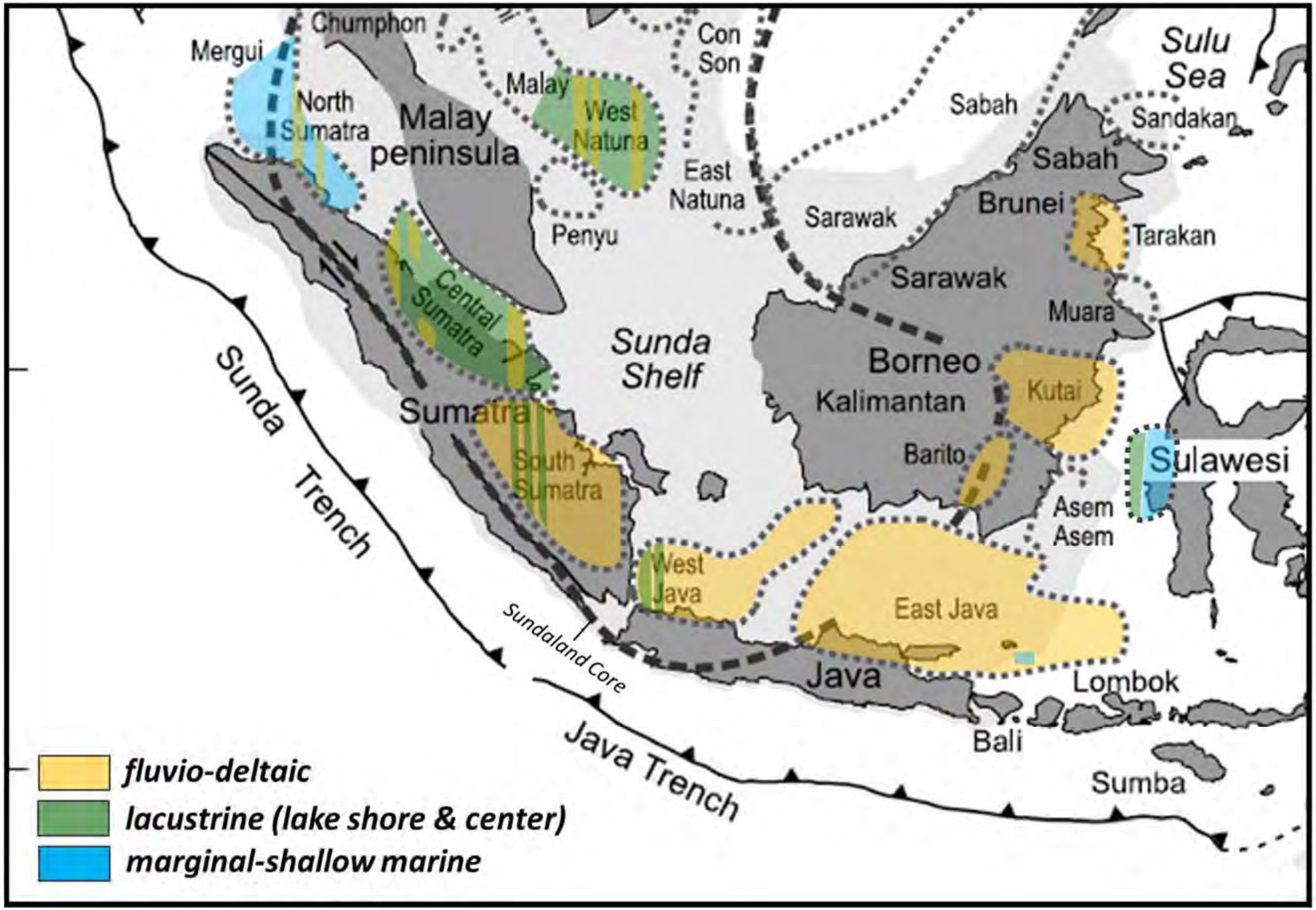
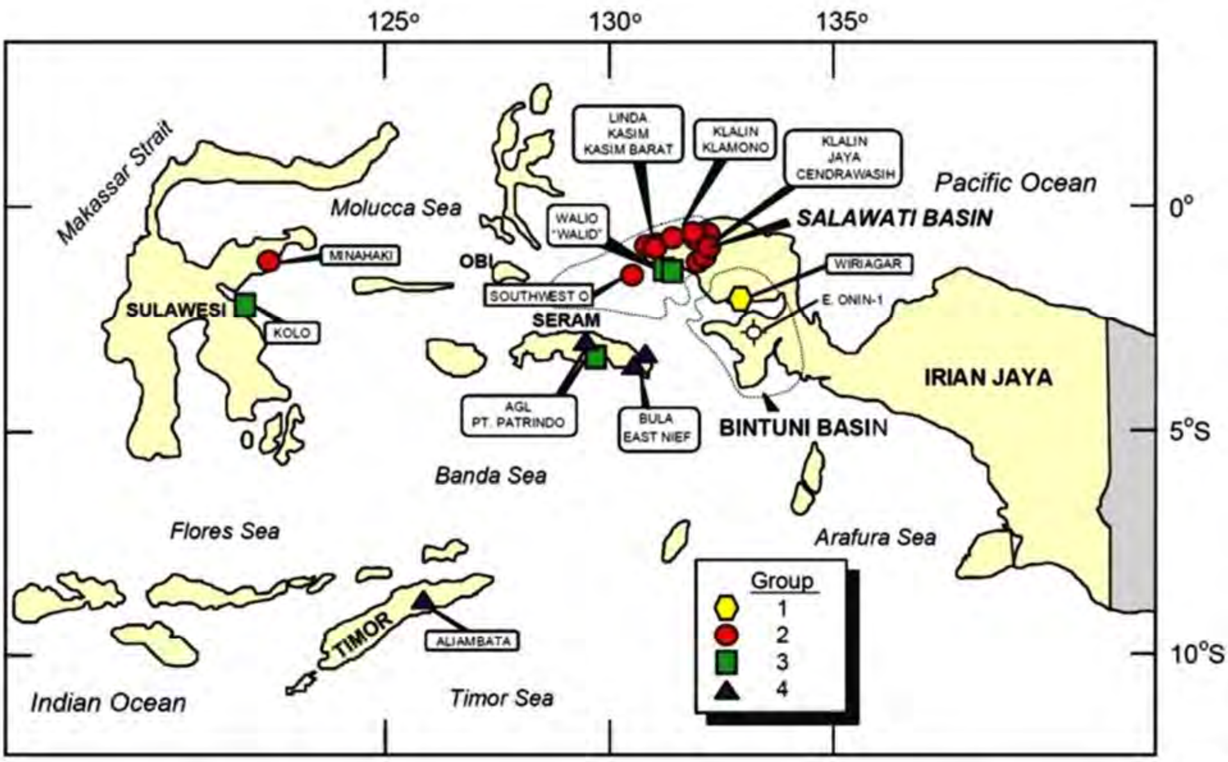


Figure 2 - Major source facies and oil families of Western Indonesian basins (modified after Satyana and Purwaningsih, 2013).



	Group I*	Group 2**	Group 3†	Group 4A††	Group 4B§
Measured Oil Properties§§					
Pr/Ph	2.6	1.2–2.4	1.1–2.2	0.5–0.8	1.6
Wt. % Sulfur	0.1	0–0.2	0–0.4	0.9–3.0	0.1
°API	39	32–37	27–33	15–24	25
$\delta^{13}C$ (‰)	−25.4	−18.9 to −22.7	−22.1 to −23.4	−28.6 to −28.8	−29.7
OL(OL + H)	0	0.49–0.73	0.24–0.48	0	0
24/(24 + 27)	0.38	0.25–0.39	0.27–0.35	0.22–0.29	0.15
Inferred Source-Rock Characteristics					
Age	Lower–Middle Jurassic	Miocene	Miocene	Triassic–Jurassic	Triassic–Jurassic
Lithology	Marine clay-rich clastic	Marine marlstone	Marine marlstone	Marine carbonate	Marine shale
Redox	Oxic	Suboxic	Suboxic	Anoxic	Suboxic
Kerogen	Type II/III	Type II/III	Type II/III	Type II	Type II/III

*Wiriagar oil.
**Matoa, Linda (3), Klamono, Klalin (3), Kasim, Kasim Barat, Cendrawasih (2), Jaya, Minahaki, Southwest O oils.
†Walio, "Walid," Oil A, Kolo, Point Patrindo oils.
††KS-90-16, AGL 13S5, Bula, E. Nief, Oil B oils.
§Aliambata oil.
§§Pr/Ph, wt.% sulfur, and API gravity values are for nonbiodegraded or mildly biodegraded samples. Ol/(Ol + H) = oleanane/(oleanane+hopane); 24/(24 + 27) = C_{26} (24-nordiacholestanes, 20S + 20R)/(24– + 27-nordiacholestanes (Holba et al., 1998).

Figure 3 – Above - Map of Eastern Indonesia showing sample locations in the Salawati and Bintuni basins (dotted basin outlines), the Bula area on Seram, eastern Sulawesi, and Timor. Symbols at sample locations show genetic relationships. Most Tertiary (groups 2 and 3) and Triassic–Jurassic (groups 1 and 4) oils occur north and south of 2°S latitude, respectively. Below – Summary of measured oil properties and inferred source rock characteristics (Peters et al., 1999).

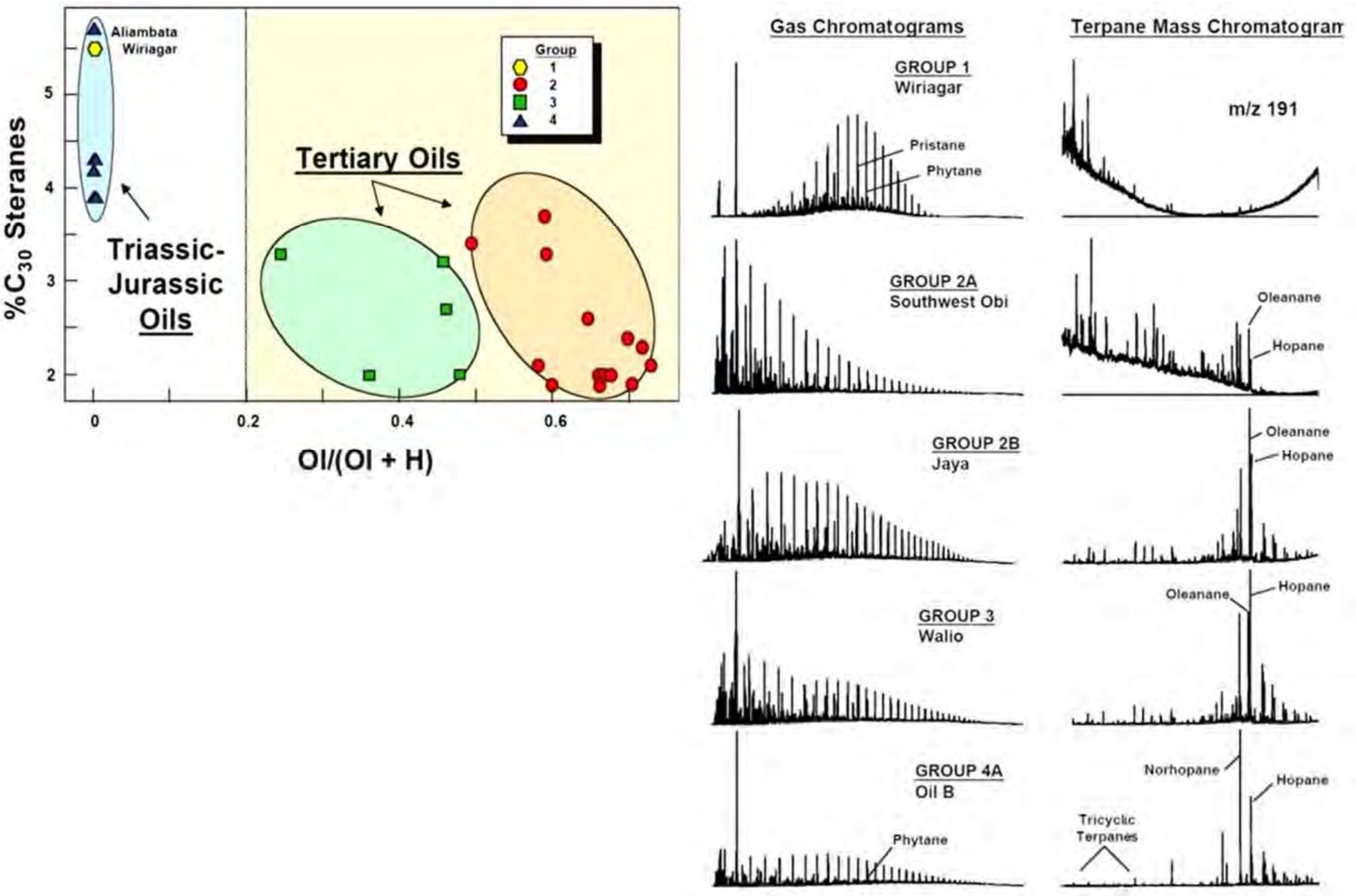


Figure 4 - Left – Plot of oleanane vs. C_{30} sterane (24-n-propylcholestane) ratios separates oil groups of Eastern Indonesia. Oleanane ratios for oils greater than 0.20 indicate Tertiary source rocks (groups 2 and 3), whereas the absence of oleanane is consistent with a Jurassic or older source (groups 1 and 4). C_{30} 24-n-propylcholestanes are diagnostic of marine source rock depositional conditions. The C_{30} sterane ratio generally increases with marine vs. terrigenous organic-matter input to the source rock. Left – Representative gas chromatograms (left) and terpane mass chromatograms (m/z 191) (right) for the oil samples (Peters et al., 1999).

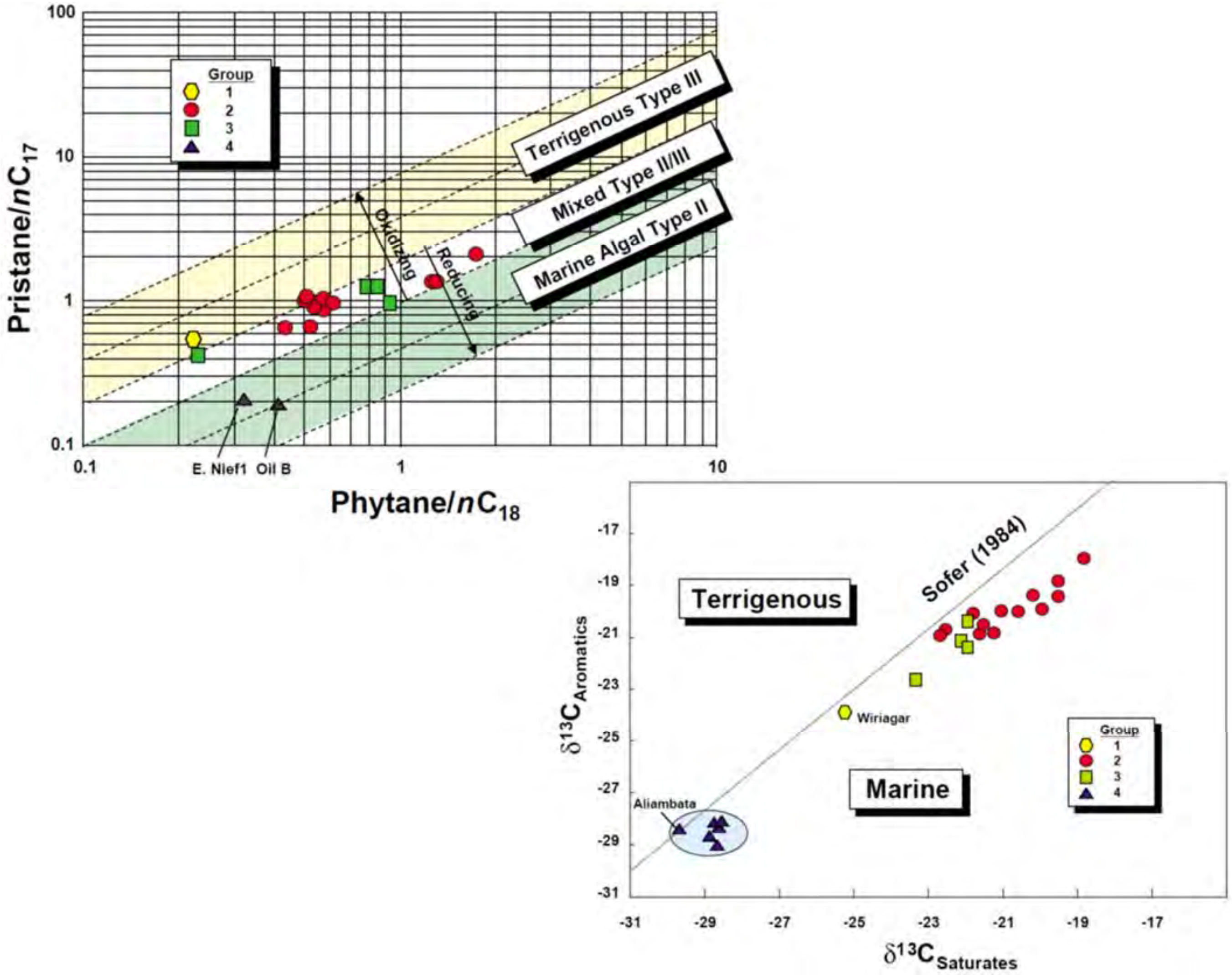


Figure 5 - Above – Plot of pristane/n-C_{17} vs. phytane/n-C_{18} from whole-oil chromatograms of Eastern Indonesian oils, can be used to infer oxicity and organic matter type in the source rock depositional environment. Below – Stable carbon isotope ratios for saturated vs. aromatic hydrocarbons differ between the Eastern Indonesian oil groups, can be used to infer the relative amounts of terrigenous vs. marine organic matter in their source rocks (Peters et al., 1999).

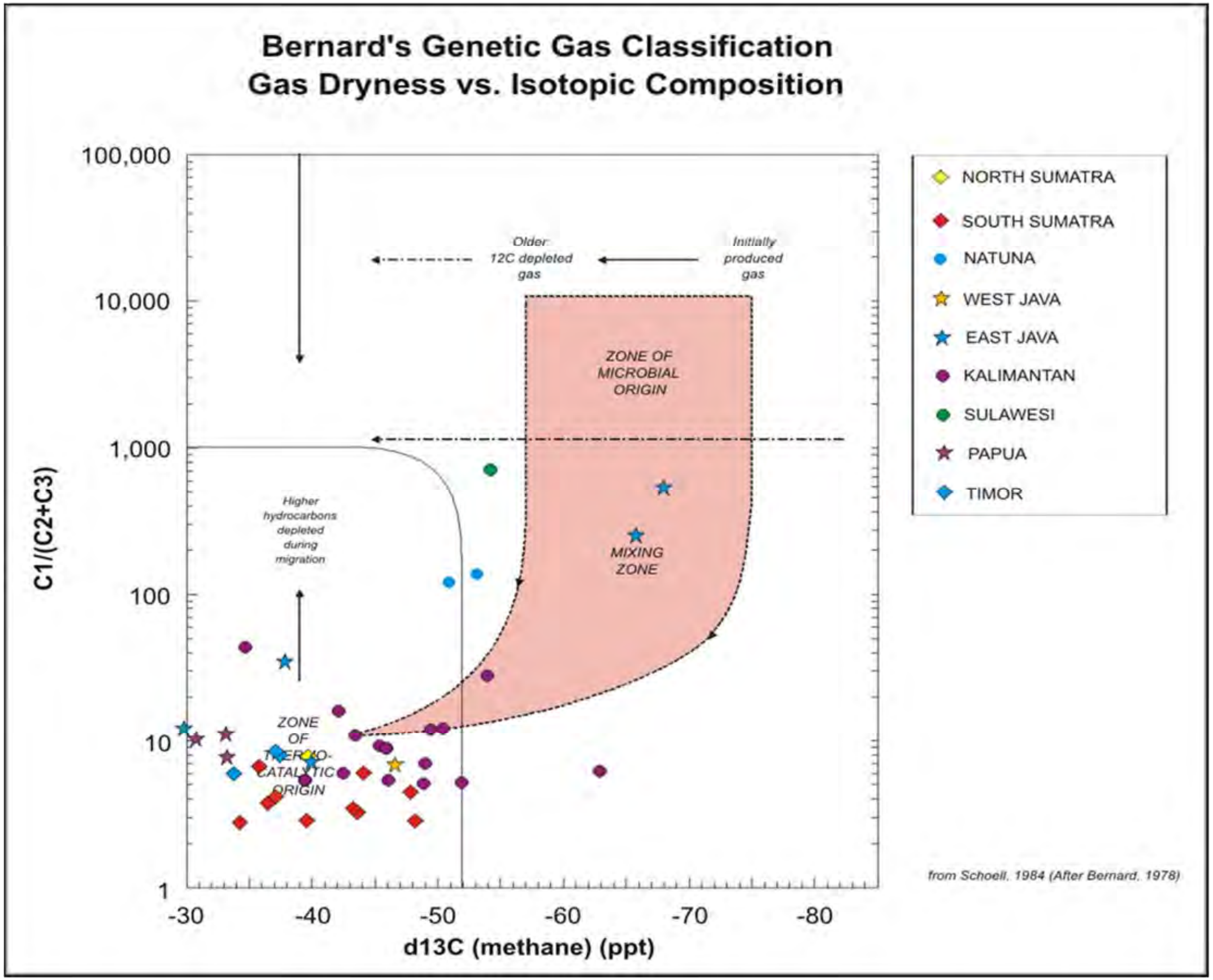


Figure 6 - Bernard's (1978) genetic gas classification for Indonesian gases, plotting between gas dryness and δ13C isotopic composition, showing most of the gases are thermogenic origin, some mixing with biogenic/microbial origin are observed (Satyana et al., 2007).

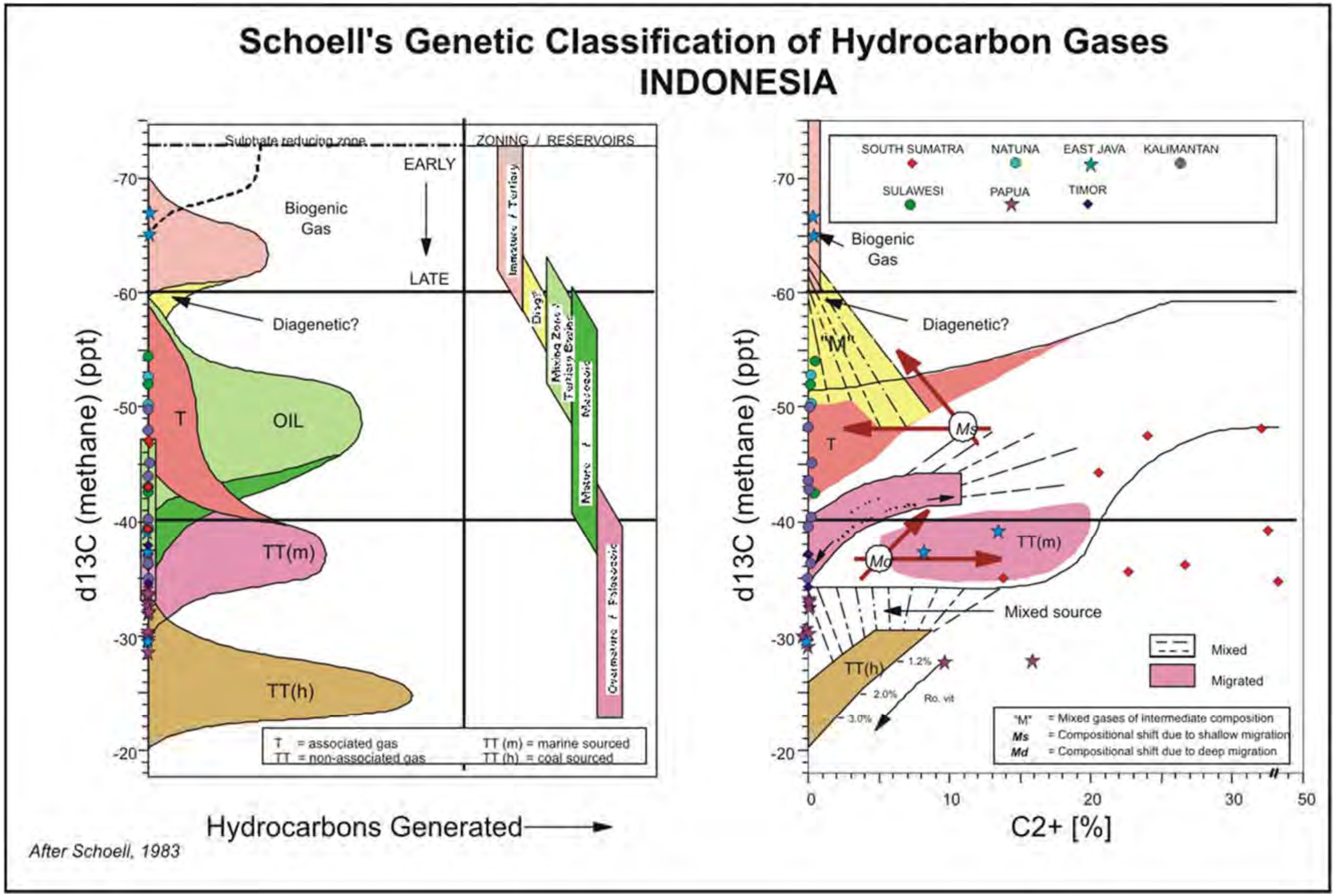


Figure 7 - Schoell's (1983) genetic gas classification for Indonesian gases, plotting between C_{2+} and δ13C isotopic composition, showing most of the gases are thermogenic origin, some mixing with biogenic/microbial origin, and biogenic gases are observed (Satyana et al., 2007).

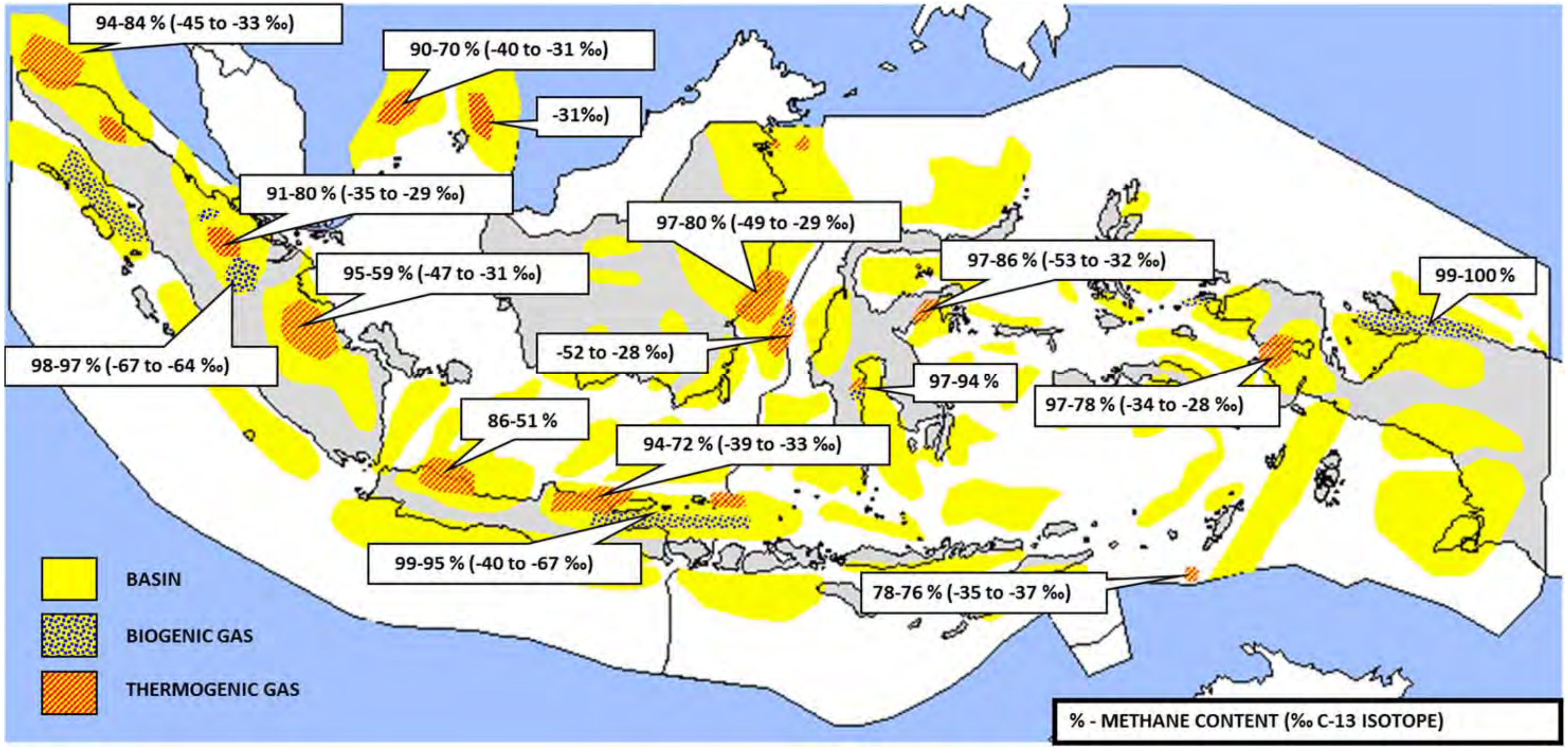


Figure 8 - Genetic gas types of Indonesia. Distribution of the gas accumulation is based on the existing gas fields. Thermogenic gases dominate the genetic type of gases and found in many basins. Significant biogenic (bacterial) gases of Indonesia distribute in three areas: forearc basin of Meulaboh-Sibolga-Mentawai west of Sumatra, Kendeng Deep-Madura Strait in East Java, and along the foredeep area of the Sorong Fault in northern Papua (Satyana et al., 2007).

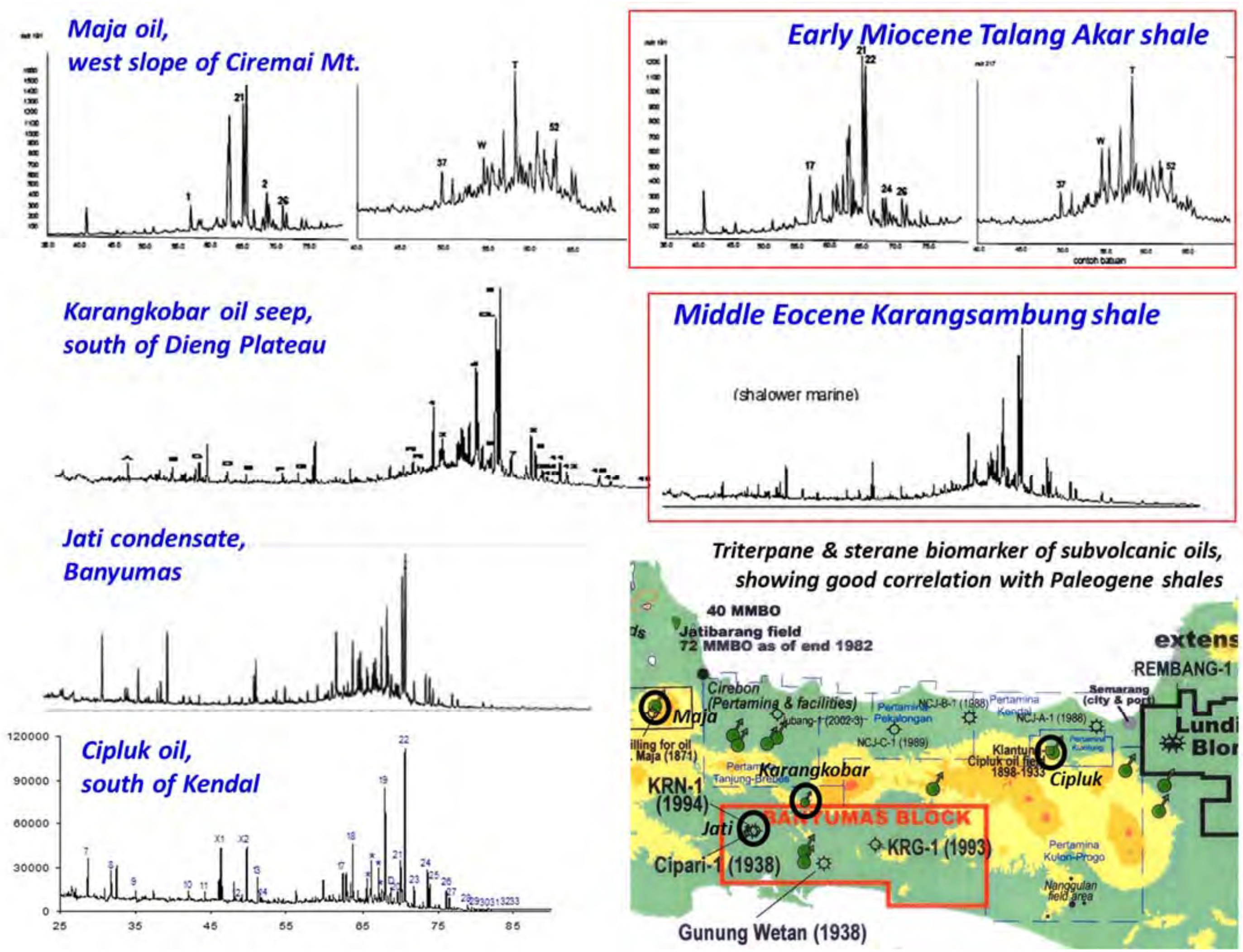


Figure 9 - Map showing the oil seep distribution in Majalengka-Banyumas and North Serayu areas, also locations of wells and field. The oil seeps are mostly located at the volcanic area. Biomarkers (triterpane and sterane) of some oil seeps/field/well: Maja, Karangkobar, Jati, Cipluk are shown, correlatable with biomarkers of Early Miocene Talang Akar shales and Middle Eocene Karangsambung shales, indicating that the oils are sourced by Paleogene shales (Satyana, 2015).

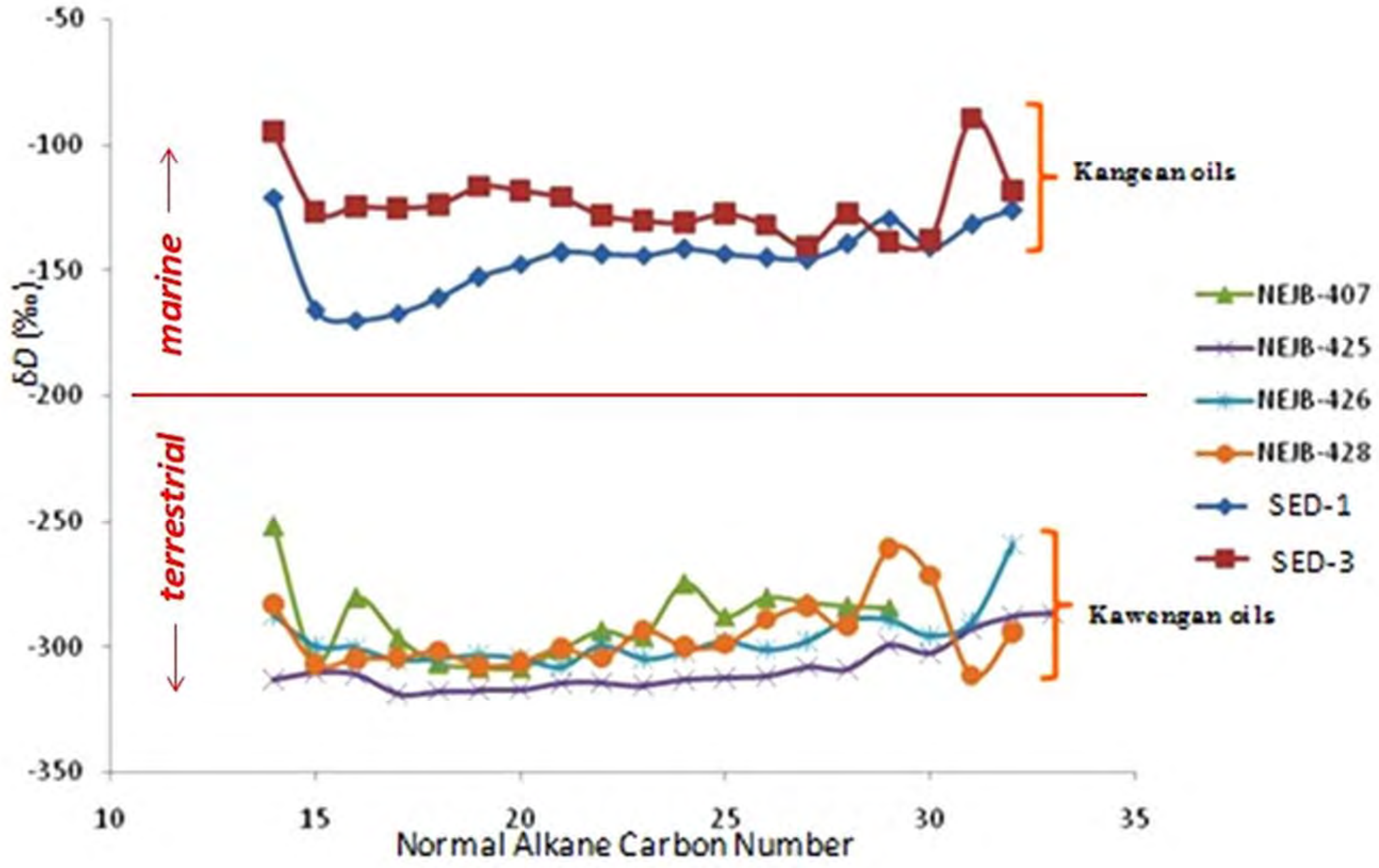


Figure 10 - Detailed δD (‰) profile difference on normal alkanes carbon number between Sepanjang/Kangean oil and East Java/Kawengan oil. Obvious difference immediately shows up, Sepanjang oil is marine (δD > -200 ‰), whereas Kawengan oil is terrestrial (δD < -200 ‰) (Musu and Sutanto, 2015).

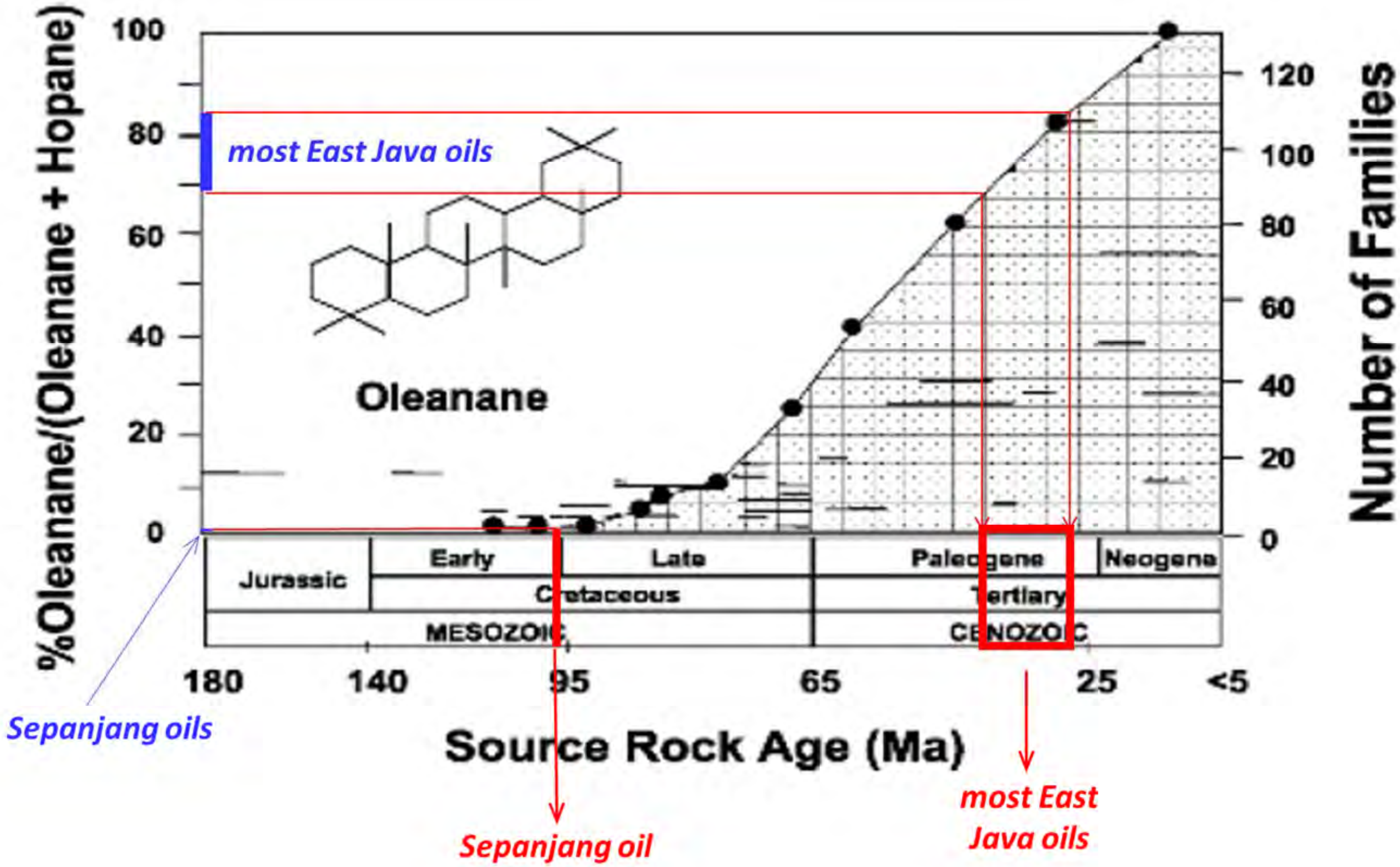


Figure 11 - Cross plot of oleanane index (oleanane/oleanane + hopane) of East Java oils and Sepanjang oil and source age. Oleanane index > 0.20 (> 20 %) indicates Tertiary source rocks (Moldowan et al., 1994). Most of East Java oils have oleanane index around 0.7-0.8, showing Paleogene source age. Very low oleanane index of Sepanjang oils (0.09) shows a contribution from Lower Cretaceous source rocks.

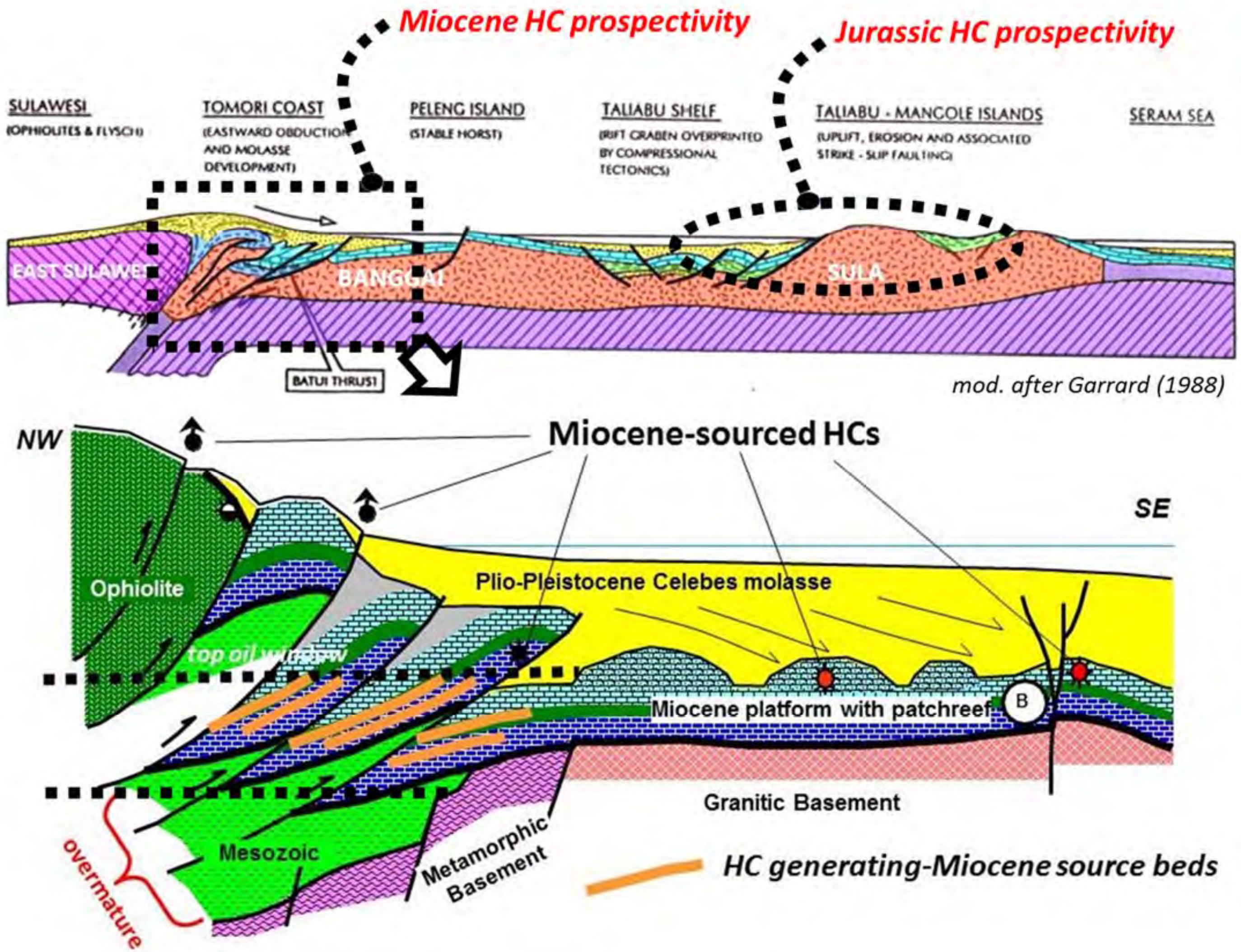


Figure 12 - Exploration implications based on the origins of oils and gases in the Banggai-Sula microcontinent (Satyana and Zaitun, 2016). Future exploration should target: (1) Miocene objectives in the Banggai Basin, since Mesozoic sources in the Banggai Basin could be overmature, and (2) Pre-Cenozoic (Jurassic) objectives in the offshore areas of North Taliabu-Mangole Shelf and Taliabu Shelf in Sula microcontinent.

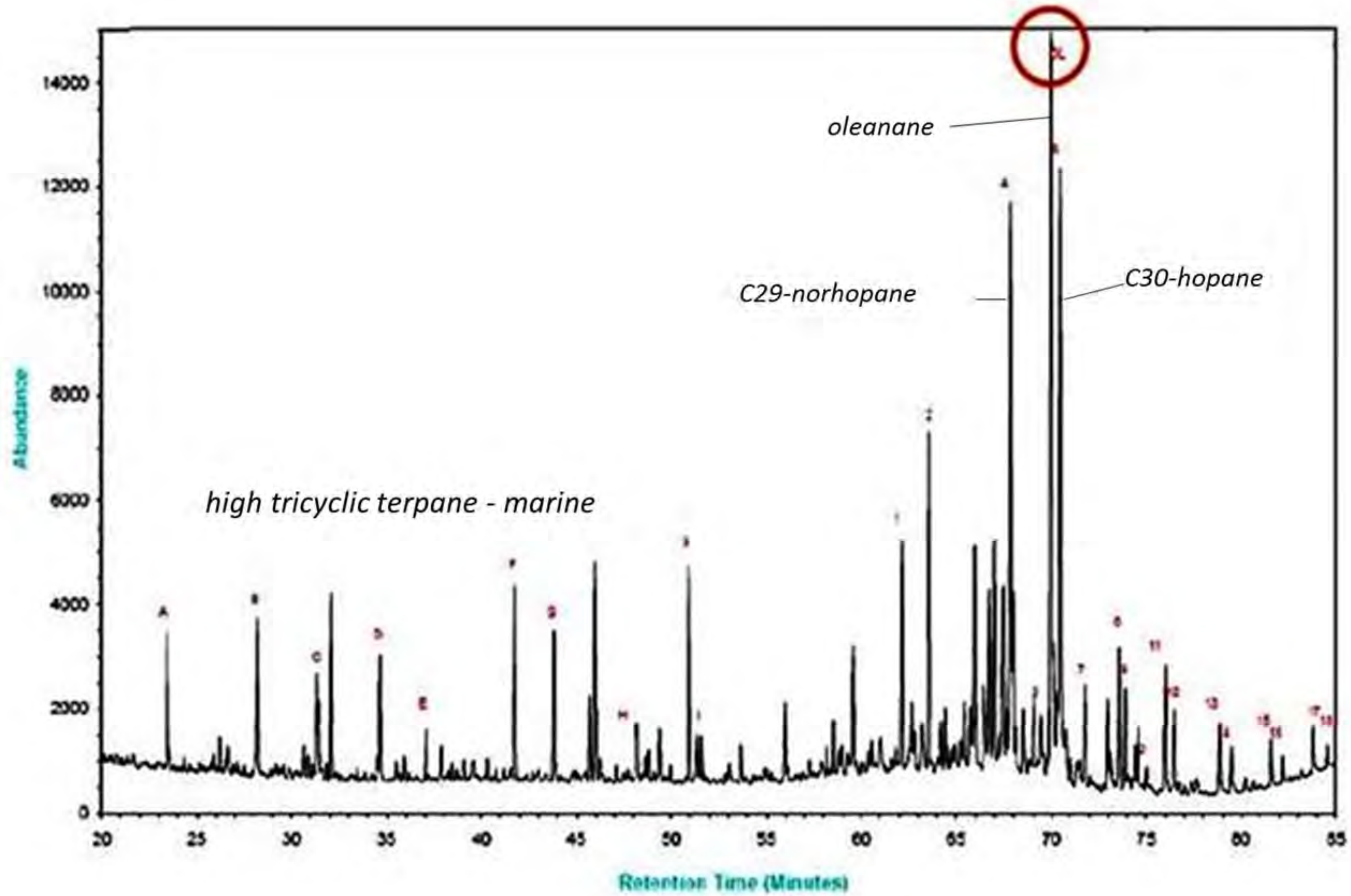


Figure 13 - Triterpane distribution of SWC extracted oil sample from Miocene Tondo limestone of Benteng-1 well, indicating source from Miocene marine shales, rich in oleanane (red circled) (Satyana et al., 2013).

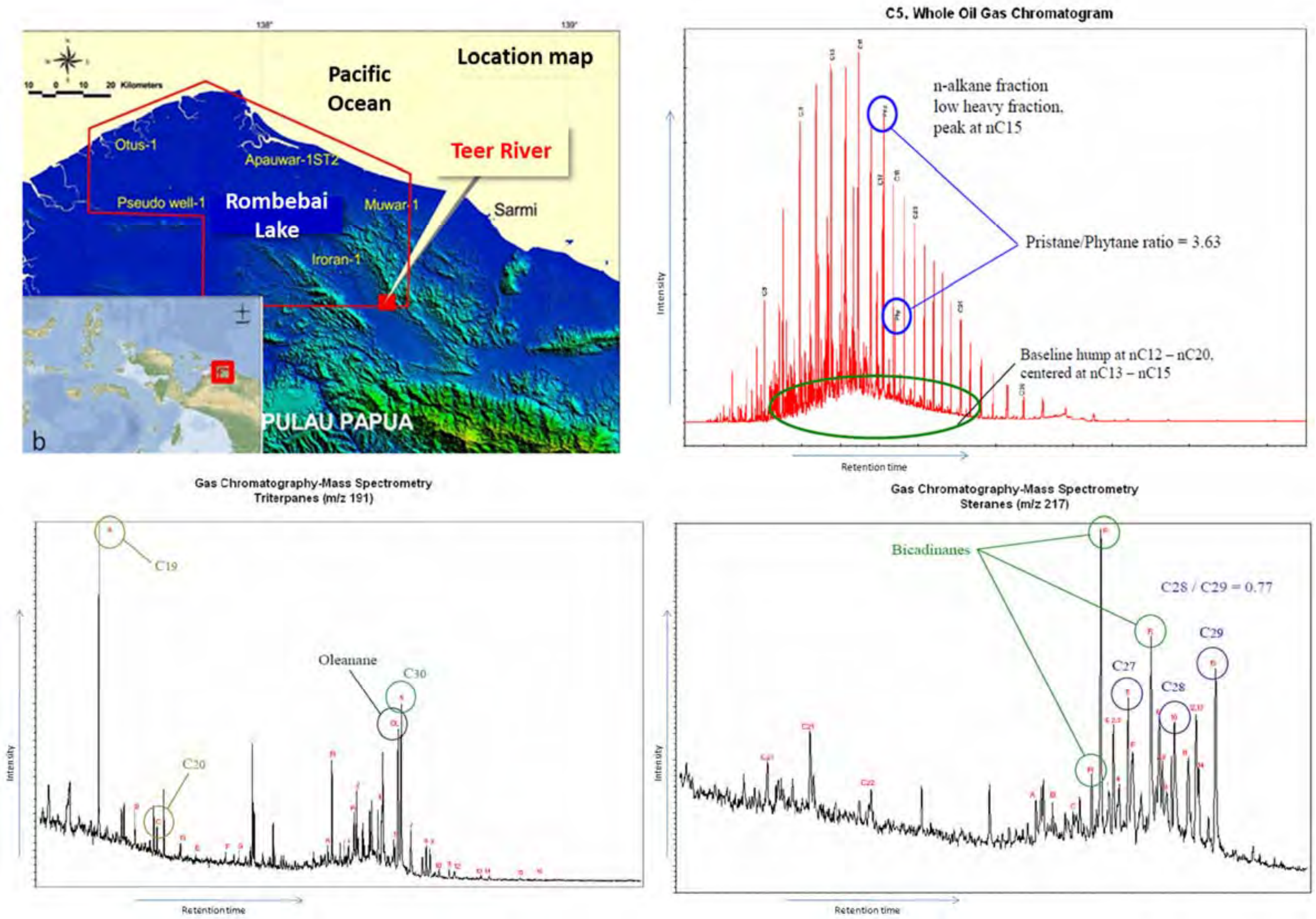


Figure 14 - Oil seep of Teer River, North Papua. Gas Chromatography of oil shows pristane/phytane of 3.63, indicating oxic condition of the source. Triterpane (m/z 191) of oil shows abundant oleanane peak of higher plant as an indication of terrestrial Tertiary organic materials. Sterane (m/z 217) of oil shows the occurrence of bicadinane as an indication of higher plant materials within Tertiary shales (Musu et al., 2015).