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REVIEW OF INDONESIA'S PETROLEUM EXPLORATION 2000 - 2015: WHERE FROM

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ABSTRACT

Fifteen years of exploration activity from 2000 to 2015 in Indonesia were reviewed. These "where from" activities provide lessons, both in cases of success and failure, for us to plan on "where to" go for future exploration.

Investment in petroleum exploration in Indonesia showed high performance during this period as can be seen by a significant increase of contract area licensing, including both conventional and unconventional hydrocarbon contracts. The number of contracts increased from 110 areas in 2003 to 312 areas in 2015. However, this has been followed by a decline since 2012 due to global lower oil price.

Indonesia was the leader in the number of 2D and 3D seismic surveys in Southeast Asia during the period. In addition, 974 exploration wells were drilled from 2002 to 2015. There was a total of 676 New Field Wildcats (NFW), with 310 wells discovering hydrocarbons, resulting in NFW technical success ratio of 46 %. New technical resources in place from 2000 to 2015 discoveries was 18,500 MMBOE.

Significant discoveries during 2000-2015 in Western Indonesia can be grouped into these play concepts: (1) Paleogene deeper/syn-rift sections of Sumatra, West Java, West Natuna Basins, (2) pre-Cenozoic fractured basement of South Sumatra, West Java, East Java Basins, (3) Oligo-Miocene carbonate build ups of East Java and Upper Kutai Basins, (4) Mio-Pliocene deep-water turbidites of North Makassar and Tarakan Basins, and (5) Mio-Pliocene growth-faults of delta progradation of Tarakan Basin. Significant discoveries during 2000-2015 in Eastern Indonesia can be grouped into these play concepts: (6) Australian Jurassic passive margin sediments, and (7) carbonates-reefal build up or fractured carbonates (Miocene and Jurassic).

During 2002-2015, there were 388 dry wells, located in various places and play concepts, including: exploration immature areas of Western Indonesia (forearc basins of Sumatra and Java, intra-cratonic basins of Sundaland, Bogor Trough), West Sulawesi offshore, Mesozoic and Paleozoic Australian province, and Neogene Pacific province. These "failure" cases have provided lessons for better future exploration.

INTRODUCTION

Oil and gas have played an important role in the development of Indonesia. When the development of Indonesia was very intensive during 1970's to early 1990's, oil and gas became the main financial contributor since this sector accounted for more than two thirds of government revenues in 1970's to around half of the revenue in early 1990's.

However, when the oil production of Indonesia declined since mid-1990's up to the present time, the government revenue from oil and gas has played a less significant role for the development. The global lower oil price for the last two years has made the condition worse. APBN 2016 (2016's Indonesian Budget) put the government revenue from oil and gas sector at around 6 % only from total expected revenue.

Nevertheless, the oil and gas sector is not only concerned with government revenue, but also with energy supply for national development. Indonesia depends heavily on oil and gas for its energy supply. This will continue for many years to come since utilization of non-oil and gas as a source of energy has been delayed. Indonesia currently imports crude oils and fuels above its own production level to fulfill the domestic energy demand. Accordingly, the oil and gas sector will remain important for Indonesia. Issues related to oil and gas exploration and production will be always interesting and important.

The declining oil production since the mid-1990's and hence declining government revenue from oil and gas, is a matter that also concerns exploration activity. Most exploration has taken place in mature areas where oil and gas have been produced for several decades to over one hundred years.

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Exploration in these areas is still successful, but generally with smaller volumes being discovered. Exploration in immature or frontier areas has taken place in some cases, but usually the areas have not been systematically explored, making the true hydrocarbon potential unclear.

Exploration is always important, since when there is no exploration, it will eventually lead to reduced production, or no production. Indonesia still has broad areas to explore. The geology of Indonesia is complicated, with a variety of petroleum systems to develop. Considering that vast areas of Indonesia are still under-explored with new and interesting geology, therefore executing exploration programs is still very worthwhile. But firstly we need to review what has happened in oil and gas exploration in Indonesia since the early 2000's, learning lessons as the basis for further exploration. In this context, "where from" will determine "where to" exploration.

The paper reviews the issues related to oil and gas exploration, mainly its technical aspects, from the early of 2000's to 2015.

DATA & METHODS

Many papers and reports, both published and unpublished, form the main data for this study. They are reviewed to compile the exploration trends during 2000-2015. Several important issues of exploration during the period will be highlighted and made as sections in the Results and Discussion.

The discussion is presented at two levels: (1) executive summaries of exploration trends during the period of review to give a general overview; (2) deeper technical aspects of success or failure for some interesting play concepts to derive learnings from the exploration history.

RESULTS & DISCUSSIONS

Opening of an Era in 2000's: Discovery of Large Banyu Urip and Giant Abadi Fields

Discovery of the large Banyu Urip oil field in the Cenozoic East Java Basin (ExxonMobil Cepu, 2001) and the giant Abadi gas field in the Mesozoic Malita-Calder Basin in Indonesia's Timor Sea (Inpex Masela, 2000) are sweet openers to the new period of exploration in the 2000's.

The Banyu Urip field was discovered in the mature East Java Basin that has been producing for more than one hundred years. The Abadi gas field was discovered in a frontier basin of Eastern Indonesia. These two very significant discoveries demonstrate that both mature and frontier exploration in Indonesia is still very worthy in the period of 2000's.

The Banyu Urip field is a high relief Oligo-Miocene Kujung carbonate isolated platform onshore East Java. It rises almost 3000 feet from the surrounding carbonate platform. It is also the largest of several fields discovered in this carbonate build up trend within the Cepu Block and nearby areas including Mudi, Sukowati and Jambaran. The Banyu Urip field has been certified by ITB with more than one billion barrels of oil in place making it the largest onshore oil discovery in Indonesia in the last several decades (Musgrove and Sun, 2012). In December 2015, oil production from the Banyu Urip field has increased to more than 130,000 barrels oil per day (BOPD) following startup of the onshore central processing facility. Banyu Urip is expected to produce 450 million barrels of oil over the project's lifetime. Once full field production levels are safely reached, the project will represent approximately 20 percent (around 160,000 BOPD) of Indonesia's 2016 annual oil production target.

The Abadi field was discovered by Inpex in Masela Block in the Timor Sea close to territorial border between Indonesia and Australia at water depth between 400m and 800m. The Abadi field is Indonesia's first discovery in the Middle Jurassic Plover Formation. Geologically, the field comprises relatively undeformed Australian continental margin that extends into Indonesian waters. It lies on the eastern extremity of the Sahul Platform and occupies a large tilted fault block bounded to the east and south by the Malita-Calder Grabens. The accumulation contains a significant gas column, reservoired within shallow marine, highly mature, quartzose sandstone of the Middle Jurassic Plover Formation (Nagura et al., 2003). The field is estimated to contain 18 trillion cubic feet (TCF) of natural gas reserves. The field is now under re-evaluation for its development due to a change in approved plan of development from floating LNG to land LNG.

Discovery of the Banyu Urip and Abadi fields have boosted exploration with analogue plays in areas sharing similar geologic history. New contract areas in the East Java Basin were acquired by many operators in early 2000s targeting the Oligo-Miocene Kujung carbonates. Trends of possible development of Jurassic sandstones like in the Abadi field have become the reason for operators in Eastern Indonesia to acquire new contract areas targeting similar play concepts.

Impact of New Law on Oil and Gas to Era 2000's

Opening the 2000's era, in addition to significant discoveries at Banyu Urip and Abadi, there was also reformation on legal aspects of the petroleum industry in Indonesia. These legal aspects presented in 2001 under the Oil and Gas Law (Law No. 22 Year 2001). The executive bodies, known as BPMIGAS (SKK Migas since early 2013) and BPHMIGAS were created to address petroleum upstream and downstream activities, respectively.

Exploration and production activities were conducted based on a fiscal contractual system that relies mainly on production sharing contracts (PSCs) between government and contractors, which may include foreign and domestic companies, as well as the government-owned oil company (Pertamina). The new Oil and Gas Law creates a statutory framework for a fundamental restructuring of the oil and gas regime. The key features of this restructuring are the termination of Pertamina as the executive body in upstream oil and gas and the liberalization of the domestic oil and gas markets.

Upstream activities based on the new Oil and Gas Law are performed through production-sharing contracts or other forms of cooperation contract. The new Oil and Gas Law allows for the adoption of new forms of cooperation contract other than the production-sharing form only.

Immediate effect of the application of the new Oil and Gas Law was the significant addition of new contract areas in Indonesia since early 2000's. Pursuant to the new Oil and Gas Law, regular tender procedure, including: the preparation of bid information for new contract working area, invitation to bid, supervision of the regular tender process, and appointment of the winning bidder become the main task of General Directorate of Oil and Gas, Ministry of Energy and Mineral Resources. Later, since 2006 based on Minister Regulation of No. 40 Year 2006, the investors may propose their own preferred area/s through direct tender/direct offer mechanism. In the process of the direct tender, the investor should conduct joint study with the appointed universities. The mechanism of tender with direct offer/direct tender has added contract areas very significantly during the period of 2006-2014. This mechanism has also attracted more local companies to invest in the petroleum industry.

Exploration Trends 2000-2015

Before we discuss technical aspects of exploration that resulted in successes and failures, the exploration trends occurring during this period are highlighted.

One of the Government's effort is to increase oil and gas reserves and production by adding new contract areas through the signing of Production Sharing Contracts (PSC). During the period of 2003 up to 2015, after the application of new Oil and Gas Law 22/2001, the addition of new contract areas was very significant, much more compared to periods before 2000's (Figure 1). The number of contract areas in 2003 was 110, increasing to 312 areas in 2015. This addition also included the contract areas for unconventional hydrocarbons (coal bed methane-CBM since 2008 and shale gas since 2013). Most addition of the contract areas during the period were exploration areas (59 areas in 2003, increasing to 228 areas in 2015 including unconventional hydrocarbons, 286 % addition during eighteen years). The addition of exploitation areas during the same period were far lower than that of exploration; 51 areas in 2003 to 84 areas in 2015 (65 % addition during eighteen years). The last status of all contract areas at the end of 2015 is as follows: 84 areas of exploitation consist of 66 areas of production and 18 areas of development; 228 areas of exploration consist of 168 active areas (118 conventional and 50 unconventional areas) and 60 areas under termination process. The current status of contract areas and their distribution in Indonesia (June 2016) is shown on Figure 2.

Indonesia is still leading in contract areas in Southeast Asia but there is a declining trend in the number of new contracts since 2011. A clear increase in acreage holdings by independents and local companies is noted. Direct tender is generally more successful than regular tender. There have been no CBM awards in Indonesia since 2013, which is related to issues of productivity, land access, and rig availability.

As for seismic surveys, Indonesia still leads in the number of surveys in Southeast Asia. In general, around 25 to 30 2-D seismic surveys were carried out annually from 2001-2015. A trend of decline occurred from 2002 to 2006, then increased from 2006 to 2008 and remained high until 2014, but dropped rapidly in 2015 to only nine 2-D seismic surveys conducted during the year, reflecting global lower oil price. For 3-D seismic surveys, Indonesia is also driving the regional trend in Southeast Asia. Generally, 10 to 15 3-D seismic surveys were carried out annually from 2001 to 2010, and increased significantly to around 50 3-D seismic surveys in the last five years from 2011 to 2015.

Indonesia's contribution to regional Southeast Asia exploration drilling is clearly declining as can be seen from a number of wells drilled from 2001 to 2015. The number declined from 115 wells (NFW and appraisal wells) in 2001 to only 48 wells in 2015. This represents a drop from 48% to 25 % of Indonesia's well count in regional Southeast Asia. Regionally, the number of wells in Southeast Asia has also declined since 2011. CBM drilling somewhat softened the decline. Figure 3 shows this variation.

Technical success ratio of exploration wells (NFW and appraisal) ranges from 39 to 73%, averaging 59%, or 46% for NFW wells only. High technical success usually occurs in mature areas. Frontier plays have not been successful in generating commercial finds. Oil and gas discovered resources are both declining. It is a similar trend regionally in Southeast Asia. The number of discoveries is also in decline. Gas discoveries have been more dominant. This trend is possibly due to exploration maturity, with small to mid-size prospects being drilled (less risky) and low success rates in high impact prospects. The key successful plays include carbonates, turbidites, and deeper sections of the basin.

Significant Exploration Discoveries 2000-2015

Almost one thousand exploration wells (974 wells) were drilled from 2002 to 2015, consisting of 617 onshore and 357 offshore wells. From this number of wells, 586 wells found hydrocarbons (NFW and appraisal wells) and 388 wells were dry. During the period, there were 676 NFW, 310 wells of which discovered hydrocarbons based on well tests, resulting in a NFW success ratio of 46 % (technical success ratio). Discovered resources in place in Indonesia between 2000 and 2015 amount to 18,500 MMBOE (technical resources). Figure 3 and Figure 4 illustrate these trends.

Significant discoveries in terms of play types and/or volumetrics during 2000-2015 both in mature, growing, and frontier areas, among others are listed as follows.

Western Indonesia: BSN (Andaman Aceh), Matang (Aceh), Benggala (Aceh), Parit Minyak, Jorang Deep, Kokoh, Lampu Deep, Tilan Deep (Central Sumatra), Akatara-Selong, Pematang Lantih-appraisal (Jambi), NE Betara Base, Panen-Berkah (Jambi), Suban Barat, Karang Makmur (Jambi), Pulau Gading East (Jambi), Cantik, Ario Damar, Ridho, Piretrium, Semparuti (South Sumatra); Adik Anoa/Anoa Deep-Lama (West Natuna), Dara-appraisal (North Sokang, East Natuna); Akasia Besar, Pondok Tengah, Melandong (West Java), Karang Enggal-Karang Baru, Pondok Makmur-Pondok Berkah (West Java), Pondok Mulia, Jati Asri (West Java), SP (offshore West Java) ; Banyu Urip (Cepu), Tiung Biru, North Kedung Tuban (Cepu), Kedung Keris, Jambaran (Cepu), Sumber (East Java), Bukit Tua, Bukit Tua South (North Madura), KE series (West Madura), Sidayu appraisal, Ujung Pangkah West, Lengo-appraisal (East Java), Jeruk (Madura Straits), Maleo, MAC, MAX (Madura Straits); Kerendan West (Kutai), Piraiba (Barito), Kinanti (Pasir, South Kalimantan), Sadewa (East Kalimantan), Ruby (Makassar Straits), Ranggas (North Makassar), Jangkrik, NE Jangkrik (North Makassar), Gehem (North Makassar), Merakes (North Makassar), South Sesulu (North Makassar), Pidawan-Bajul Besar/Sembakung, Mujaer-Bunyu (Tarakan), Bedug-South Kecapi (Tarakan), Badik-West Badik (Tarakan), Aster (Tarakan).

Eastern Indonesia: Abadi (Timor Sea); Asap, Merah, Kido, Kido Steenkool, Roabiba appraisal (Bintuni); Koi (Salawati); Lofin (Seram); Senoro appraisal, Donggi, Penyu shallow (Banggai).

Significant Discovery Play Concepts 2000-2015

Significant discoveries during 2000-2015 in Western Indonesia can be grouped into these play concepts: (1) Paleogene deeper sections/syn-rift sections of Sumatra, West Java, West Natuna Basins, (2) pre-Cenozoic fractured basement South Sumatra, West Java, East Java Basins, (3) Oligo-Miocene carbonate build ups of East Java and Upper Kutai Basins, (4) Mio-Pliocene deep-water turbidites of North Makassar and Tarakan Basins, and (5) Mio-Pliocene growth-faults of delta progradation of Tarakan Basin.

Significant discoveries during 2000-2015 in Eastern Indonesia can be grouped into these play concepts: (6) Australian Jurassic passive margin sediments, and (7) carbonates-reefal build up or fractured carbonates (Miocene and Jurassic).

Discoveries in Western Indonesia can be classified to petroleum system types (PSTs) proposed by Doust and Sumner (2007), including: Early Syn-rift Lacustrine PST, Late Syn-rift Transgressive Deltaic PST, Early Post-rift Marine PST, Late Post-rift Regressive Deltaic PST. Additional and related to these are: Pre-rift Basement, and Late Post-rift Marine Turbidites (Figure 5).

Nayoan et al. (1991), modified by Satyana et al. (2008) recognized five major pre-Tertiary/pre-

Cenozoic exploration plays or exploration fairways regionally in Eastern Indonesia. Three of which are related to Australian continental margins. The other two are respectively collision and subduction-related. They are: Paleozoic Pericratonic Graben, Mesozoic Marginal Rift Graben, Fold and Thrust Belt of Papua, Microcontinental Collision, and Passive Margin-Island Arc Collision.

(1) Paleogene Deeper Sections / Syn-rift Sections of Sumatra, West Java, West Natuna Basins (Early Syn-rift Lacustrine and Late Syn-rift Transgressive Deltaic PSTs)

The Paleogene sections, deposited as late syn-rift and mainly post-rift sequences mostly inverted in the late Neogene forming inverted faulted anticlinal traps in Sumatra, Natuna, Java, and Kalimantan basins (such as: Minas, Duri, Talang Akar, Belida, Tanjung fields) have been explored since early days of exploration in Western Indonesia due to their shallow positions by structural inversion. Deeper Paleogene sections of syn-rift sequences however, remained unexplored until the late of 1990s.

Courteney (1996) predicted that the key to the future exploration potential of Western Indonesia lay within these deep sedimentary sections that exist within rifts in every basin of Western Indonesia. The sediments are interpreted as Middle Eocene or older, to Early Oligocene, and contain the effective source rocks together with reservoirs and seals. Potential traps will tend to be inversion structures (such as Jatibarang Field, Northwest Java), or stratigraphic/ structural traps on the hanging walls of the rifts. Courteney (1996) estimated potential resources in place of the deeper Paleogene sections of Western Indonesia are greater than 6.6 billion barrels of oil equivalent (unrisked).

Doust and Sumner (2007) classified these targets of deeper Paleogene sections of syn-rift sequences as Early syn-rift lacustrine petroleum system type (PST). This is strongly oil prone due to the widespread development of organic-rich lacustrine source rocks, and regionally is common in basins in Thailand, Vietnam and western Indonesia. The related oils are characteristically light (40° API), waxy and low in sulfur. Most of the oils are derived from lacustrine and fluvio-lacustrine source rocks rich in algal organic material (Type I/II), while minor amounts of gas are contributed by Type III coals and coaly shale source rocks that occur in small marginal lake swamp facies. Reservoirs comprise fluvio-lacustrine clastics (including lacustrine turbidites), lacustrine carbonates and volcaniclastics of limited quality and areal extent. These reservoirs are interbedded with laterally discontinuous non-marine shale seals that allow charge to leak into the overlying late syn-rift transgressive delta sequence. Charging of fractured basement occurs locally where the lacustrine source rocks lap onto or are juxtaposed against basement horsts.

Numerous discoveries during 2000-2015 of this type occurred in deep Paleogene sections of syn-rift and late syn-rift sequences of sedimentary basins in Sumatra, West Java, and West Natuna. They are, among others: Matang, Benggala (North Sumatra), Tilan Deep, Jorang Deep, Parit Minyak, Kokoh (Central Sumatra), Akatara, Selong, Panen, Panen Utara, Berkah, Karang Makmur (South Sumatra), Melandong, Pondok Tengah, Pondok Mulia, Karang Baru, Karang Enggal (West Java), Adik Anoa (West Natuna).

(2) Pre-Cenozoic Fractured Basement South Sumatra, West Java, East Java Basins (Pre-rift Basement)

Basement rocks are important hydrocarbon reservoirs in various areas of the world. In Indonesia historically, several fields produced oils from basement reservoirs (Kluang and Teras fields in South Sumatra, Tanjung field in South Kalimantan), but hydrocarbon exploration into the basement was started in 1976 when Beruk Northeast-1 well drilled the pre-Tertiary basement to explore the oil in Central Sumatra Basin and tested oil (Koning and Darmono, 1984). However, intensive exploration into the basement occurred in late 1990s when Gulf Resources explored South Sumatra’s basement in Suban structure. The Suban field was discovered in 1998 with the drilling of Suban-2 which encountered high deliverability gas in fractured pre-Cenozoic andesite and overlying sandstone of the lower Talang Akar Formation (Pujasmadi et al., 2002).

Currently, since the discovery of giant Suban gas field in Jambi (5 TCF; Koning, 2015), South Sumatra Basin, this play-type has been targeted in basins of Sumatra and Java. Several exploration efforts during 2000-2015 resulted in some significant discoveries. Fractures in the basement are believed to have formed by: (1) contraction joints within pre-Cenozoic igneous rocks during cooling of the rocks, (2) fractures and faults formed during multiple stages of tectonic readjustment, and (3) fractures formed during uplift (uploading) and surface weathering. The degree of fracturing varies with the age and kind of rocks. Older and brittle rocks contain more faults and fractures than those of younger and ductile rocks.

As for the charging, the basement horst block should be flanked or encircled by grabens containing mature source rocks. Generated hydrocarbons will migrate onlap to the fractured basement in the horst blocks.

To date in Indonesia, hydrocarbon production from basement rocks has been minimal but major gas discoveries in South Sumatra including the giant Suban gas field have triggered basement exploration in Indonesia during the period of 2000-2015. Some discoveries in the pre-Cenozoic basement following the success of Suban field are: Suban Barat, Karang Makmur, Kenanga (South Sumatra), Pondok Makmur (West Java), KE 29-1 (East Java).

Koning (2015) provide best practices working with basement, as follows.

1) Highly focused 3D seismic such as CBM (Controlled Beam Migration) is needed to define the fracture systems in basement.

2) Exploration wells should not just “tag” into the top of basement. Rather they should be drilled 100 – 200 meters into the basement in order to fully evaluate it.

3) Exploration wells should also be drilled highly deviated rather than vertical in order to optimally intersect the dominant fracture systems.

4) Extensive core coverage is necessary to provide critically important information on the lithologies and reservoir parameters. Some of the cores should also be radiometrically age dated in order for the geologists to understand the complexities of the basement reservoirs they are dealing with.

5) Development wells must be sufficiently deep to fully drain the reservoir. For example wells in the La Paz field, Venezuela which produces from basement were typically drilled 500 meters into the basement.

6) Production wells should be drilled near-perpendicular to the dominant fracture system.

(3) Oligo-Miocene Carbonate Build Ups of East Java and Upper Kutai Basins (Early Post-rift Marine PST)

Discovery of the large Banyu Urip oil field in East Java Basin (ExxonMobil Cepu, 2001) triggered enhanced exploration efforts in the entire East Java Basin. The Government of Indonesia (GOI) offered many contract areas in the basin with the main objective of exploring similar plays as Banyu Urip. Many operators picked up the contract areas exploring the targets both offshore and onshore.

Banyu Urip field is a high relief Oligo-Miocene Kujung carbonate isolated platform in onshore East Java. It rises almost 3000 feet from the surrounding carbonate platform. The Kujung carbonate had been a target of exploration since early 1970’s in offshore East Java Sea when the PSC system was just offered by the GOI in the late 1960s. Exploration efforts until the mid-1980’s were rewarded with discoveries of fields like Poleng, Camar, KE5 and KE2 fields. After these discoveries, the offshore exploration activities decreased. Exploration efforts in East Java Basin shifted its focus to onshore area targeting Neogene siliciclastic objectives. But in 1994, a significant discovery occurred in onshore Cepu area when the Mudi field was discovered. The field has an Early Miocene carbonate reservoir.

Intensive exploration for Oligo-Miocene carbonates of the East Java Basin took place in the late of 1990’s and early 2000’s, mainly in offshore area. During the period, significant discoveries of Ujung Pangkah and Bukit Tua fields took place (later it was known by absolute age dating that the Bukit Tua reservoir is mainly Early Oligocene CD carbonates). Numerous hydrocarbon discoveries also occurred in the Early Miocene patch reefs of the West Madura offshore area. These discoveries peaked with the discovery of Banyu Urip field in onshore Cepu. Discovery of Banyu Urip then triggered other discoveries in the onshore Cepu area.

Satyana and Darwis (2001), Satyana (2002), and Satyana and Djumlati (2003) have provided information on the petroleum geology of hydrocarbon discoveries in the Oligo-Miocene carbonates of East Java Basin.

Some discoveries of this play type during the period of 2000-2015 are: Banyu Urip, Tiung Biru, Jambaran, Kedung Tuban, Kedung Keris, Sukowati (onshore East Java); Sidayu, Bukit Tua, numerous KE series, Jeruk, Lengo (offshore).

It is also important to mention here the discovery of gas and condensate within Early Miocene Berai reefal build up of West Kerendan in the Upper Kutai Basin. High delivery of gas at a rate of 51 MMCFGPD and condensate at 230 barrel per day were tested from West Kerendan. The first discovery of gas and condensate in this area took place in the mid-1980's when the Kerendan field was discovered by Union Oil. Efforts to discover additional hydrocarbons with a similar play type in the area have been largely successful, until Salamander drilled the West Kerendan structure in 2013 and tested gas and condensate. Reefal build ups here are scarce, growing on isolated basement highs off the Barito Platform at the southern part of Upper Kutai Basin in the Bongan Deep.

(4) Mio-Pliocene Deep-Water Turbidites of North Makassar and Tarakan Basins (Late Post-rift Marine Turbidites)

In the late of 1980's the concept of a deep-water play came into being, that is, transportation and redeposition of deltaic material into deep water areas. The play was aided by concepts of seismic stratigraphy and sequence stratigraphy. During low stands of sea level, the deltaic deposits are eroded, transported to deeper areas and deposited in slope and basin floor settings. Packages of redeposited deltaic reservoirs and source rock materials can generate and trap petroleum. The concepts were successful in the discovery of petroleum in many deep water areas, like in the Gulf of Mexico, the Niger in West Africa, Campos Basin of Brazilian, and the North Sea. This was extended to Indonesia in the early 1990's and by the late-1990's discoveries of oil and gas fields in deep water areas of the North Makassar Basin took place (West Seno, Merah Besar, Gendalo, Gada, Gula fields) (Figure 6).

The trend of discoveries continued during the period of 2000-2015 with discovery of Ranggas, Gehem, Jangkrik, Northeast Jangkrik, Merakes, and SIS-A South Sesulu taking place. A similar discovery of Mio-Pliocene deep-water turbidites also occurred in the Tarakan Basin, namely the Aster field.

(5) Mio-Pliocene Growth-Faults of Delta Progradation of Tarakan Basin (Late Post-rift Regressive Deltaic PST)

Growth faulting characterizes the structural style of the Tarakan Basin (Figure 6). The origin of growth faulting relates to delta progradation from an uplifted provenance in the western part of the basin to subsided deposition eastwards. Growth faulting develops to accommodate gravity tectonics of sediment progradation. Roll over structures develop on downthrown fault blocks commonly becoming hydrocarbon traps associated with growth faulting. This process also occurs for oil and gas fields in the Tarakan Basin, where roll over structures are the result of growth faulting. The Tarakan examples are: Sembakung, Bangkudulis in the onshore area, and all fields on the Tarakan and Bunyu Islands.

The trend of discoveries in the Tarakan Basin during 2000-2015 occur in this play type in both onshore and offshore areas. Typical discoveries are: Pidawan, Bajul Besar in onshore Sembakung area, Mujaer in Bunyu Island, and Bedug-South Kecapi, Badik-West Badik in the offshore area.

(6) Australian Jurassic Passive Margin Sediments (Mesozoic Marginal Rift Graben)

The Mesozoic (and Late Paleozoic) sedimentary rocks were firstly considered to be hydrocarbon prospective in Eastern Indonesia based on numerous fields in the NW shelf area of Australia and onshore West-Central Papua New Guinea, The reservoirs are Permian to Cretaceous sandstones and/or carbonates. The Jurassic is the most prolific reservoir and source from these sequences. Tectonically, these sediments were deposited in rifted basins formed along the Australian continental passive margin which extends into Eastern Indonesia area (Figure 7).

In Indonesia, the Jurassic source rocks and reservoirs are proven to be prospective and productive by discoveries of large to giant gas fields in offshore Berau Bay and Bintuni Basin (Bird's Head of Papua) presently known as the Tangguh field complex (Vorwata, Wiriagar Deep, Roabiba, Ofaweri, Wos, Ubadari) with total reserve potential estimated at 24 TCFG / 4 BBOE (Casarta et al., 2004) and Abadi field in offshore Masela area, Timor Sea (total reserve potential estimated at 18 TCFG).

Casarta et al. (2004) provided the analysis of the petroleum geology of the Tangguh field complex. Middle Jurassic shallow marine to deltaic sandstones form the main reservoirs of the Tangguh field complex. The Late Jurassic and Cretaceous marine shales are described as being the primary sealing lithology for the Middle Jurassic reservoirs. Permian and Early to Middle Jurassic coals/shales are described as the primary source rocks. The trapping structures were formed by the Miocene to present-day compressional inversion. The hydrocarbons are modeled to have been generated at approximately 5 to 3 Ma, migrating up dip through Jurassic sandstone carrier beds charging the available traps. Hydrocarbon generation continued from 3 Ma to the present day in optimum thermal maturity zones rimming the northern, western, and southern margins of the Bintuni Basin.

Abadi field geologically, comprises relatively undeformed Australian continental margin that extends into Indonesian waters. It lies on the eastern extremity of the Sahul Platform and occupies a large tilted fault block bounded to the east and south by the Calder-Malita Grabens (Nagura et al., 2003). The accumulation contains a significant gas column, reservoired within shallow marine, highly mature, quartzose sandstone of the Middle Jurassic Plover Formation. Close analogues are to be found in the giant Greater Sunrise and Bayu- Undan fields. The source for the Abadi gas is postulated to be laterally equivalent marine shales deposited contemporaneous with the Plover Formation.

Thermal maturity studies indicate such source rocks should be mature for gas in the Calder-Malita Grabens, Masela Deep, and directly down-dip from the Abadi field towards the Timor Trough. The Abadi structure is a paleo high that has been reactivated and modified by subsequent rifting both in the latest Jurassic/earliest Cretaceous and in the Neogene. Early Cretaceous shales of the Echuca Shoals Formation, providing the primary side-seal and top seal.

Discoveries of fields in the Tangguh field complex and Abadi field has triggered exploration efforts targeting Jurassic sections in Eastern Indonesia for the last fifteen years from 2000-2015. Exploration has taken place along the passive margin of Australia, from south of Tanimbar Island to the Semai area northeast of Seram Island, and to the south Central Range of Papua. Most of the exploration efforts were however failures due to the absence of good quality reservoirs (for example, the wells drilled in the Semai area and Sindoro-1 in SE Palung Aru area to the east of Abadi).

Successful exploration wells targeting a Jurassic reservoir analogue to the Tangguh field complex occurred in the Kasuri working area. Intensive exploration conducted by Genting since 2010 has been rewarded with some significant discoveries, including: Asap, Merah, and Kido fields. The discovery play type is similar with the Tangguh complex.

(7) Carbonates-Reefal Build Ups or Fractured Carbonates - Miocene and Jurassic (Microcontinental Collision, and Passive Margin-Island Arc Collision).

Discovery of hydrocarbons during 2001-2015 has occurred in the Banggai Basin of Central Sulawesi at Donggi, Maleo Raja, Sukamaju, Cendana Pura, Grupa, and Penyu structures, as well as Senoro appraisal. There has also been a significant discovery at the Lofin structure, Seram Island. The results show the prospectivity of microcontinental collision and island arc-passive margin collision areas in Eastern Indonesia (Figure 7). The collision involved Miocene reefal and platform carbonates at Banggai, and Jurassic fractured carbonates at Seram Island.

The prospectivity of microcontinental collisional areas in Eastern Indonesia was first proven by discoveries of gas at Mantawa-1 (Union Texas, 1984), in the Banggai Basin. Further gas discoveries were at Matindok and Minahaki in 1984, and an oil discovery at Tiaka in 1985. The prospectivity of microcontinental collision at Seram was first proven by an oil discovery at Oseil structure (ARCO/Kufpec, 1993).

The Banggai microcontinental block is thought to be originally located east or southeast of its current position. It drifted westward or northwestward towards the eastern margin of Sundaland and collided at Sulawesi in the Neogene. The collisional process resulted in considerable folding, thrusting and imbrications of the sedimentary section deposited during the pre-rifting, rifting, and drifting stage of the microcontinent, and obduction of ophiolitic mass located in the center between Sulawesi and the Banggai microcontinent. The collision formed the Banggai foreland basin, with Miocene calcareous source rocks underthrusted and driven to depths of the oil and gas windows. Hydrocarbons were generated and migrated up dip charging Miocene reefal build ups or collisional-deformed carbonate platform. Overlying the complicated collisional terrains lies the suspended basin where molassic Pliocene-Pleistocene clastics and carbonates were deposites. A gas discovery of Penyu shallow in 2014 occur in the molassic deposits.

In Seram, a collision involving the northern Australian continental margin and outer Banda Arc (Timor-Tanimbar-Kei-Seram) which began in mid-Tertiary time, resulted in the formation of a deformation belt between the passive margin of Australia and the outer Banda Arc stretching from Timor to Tanimbar, to Kei and Seram. The collision consists of imbricated slices of Mesozoic and Cenozoic rocks. Imbricated Mesozoic sedimentary rocks formed duplex structures and provided traps for hydrocarbon accumulation. Triassic and Jurassic rocks, providing the source and reservoir for Seram, respectively. Overlying the collisional terrains lies the suspended basin where molassic Pliocene-Pleistocene clastics and carbonates were deposited, forming fields such as the Bula field on Seram Island.

Significant Exploration "Failures" 2000-2015: Lessons Learned

Exploration drilling provides geological, geochemical, and geophysical data that can be used for building and / or confirming models of the petroleum system and play concept. When a well does not find hydrocarbons it tells us that certain elements or processes of the petroleum system are not working. Refinement or total correction of the elements and processes of the petroleum system using new data is required. Evaluation after drilling will result in two alternatives: (1) continued exploration with lower risk because the petroleum system model is refined or corrected, or (2) terminate exploration because the area is too risky and the area cannot be de-risked further using the drilling results.

Accordingly, "failures" in this case are not obvious since the exploration well can still provide useful information. The data acquired by dry wells are always beneficial for refining or correcting the petroleum system model. In frontier areas where there is no previous drilling, the risk of "failure" is higher. The first well drilled in the area cannot be burdened with a high probability of success, since if that were the case, it would mean that the area has already been de-risked. The well in a frontier area should properly test the play concept and petroleum system model, and collect as much data as possible. If the well finds hydrocarbons, it becomes a play-opener. If the well does not find hydrocarbons, the petroleum system model can be refined or corrected using new data acquired by the well. There are many fields in frontier areas were only discovered after drilling several dry wells.

During the period of 2000-2015, the technical success ratio of exploration wells (new field wildcat and appraisal) ranges from 39% to 73% (average 59%). In the "failure" case, 27% to 61% (average 41%) of the wells were dry. Almost one thousand exploration wells (974 wells) were drilled from 2002 to 2015, consisting of 586 wells which found hydrocarbons (new field wildcat or appraisal wells) and 388 wells which were dry.

High technical success usually occurs in mature areas (near-field success). Immature and frontier exploration areas have not yet been successful in generating commercial finds, which is reasonable since the areas are less understood due to lack of data and exploration activities.

In the next section, the areas discussed are as follows: (1) Exploration immature areas of Western Indonesia; (2) West Sulawesi offshore exploration; (3) Mesozoic Australian province exploration; (4) Lower Paleozoic Australian province exploration; and (5) Neogene Pacific province exploration. Significant exploration wells representing these areas can be seen on Figure 8.

(1) Exploration Immature Areas of Western Indonesia

Immature areas of Western Indonesia discussed here are: forearc basins of Sumatra and Java, intra-cratonic basin of Sundaland, Bogor Trough, and intra-arc areas of Sumatra. During the period of 2000-2015 several exploration wells were drilled in these areas.

Rendang-1 well (Total, 2014) was drilled in Mentawai forearc area targeting a Late Miocene carbonate build up. The well failed to find hydrocarbons due to poor reservoir quality and lack of charging. To the south, in the offshore Banten area M3 Company drilled the Cula-1 well in early 2016 targeting Eocene sandstones in the Ujung Kulon Block. The well penetrated the objective but failed to encounter hydrocarbons. Source immaturity is considered as the primary reason. In the onshore forearc basin of Banyumas, Central Java, the Jati-1 well was drilled by Lundin in 2005. The well did not reach the main target of Paleogene sandstones due to mechanical trouble related to overpressure. The TD of well is in the Middle Miocene Penosogan Formation after deepening. One DST tested small amount of gas and condensate from the Penosogan sandstones. The gas-condensate was geochemically analyzed and is thought to be sourced by Paleogene shales. The forearc basins of Sumatra and Java needs more exploration to examine their true potential. Source immaturity could be a main risk.

Intra-cratonic basins of Sundaland, in this case represented by exploration in the Biliton Basin, Java Sea and in the Palangkaraya Block, Central Kalimantan, have been explored. Two exploration wells were drilled by APD-Mitra Biliton, Batara Ismaya-1 (2007) and Batara Indra North-1 (2008). The two wells encountered good to excellent sandstones of the Talang Akar and Banuwati Formations, but with no shows. There appears to be no mature source rocks deposited in the nearby low area (depocenter presently at around 2.0 seconds seismic TWT). The exploration results in the Biliton Basin may disprove the hydrocarbon potential of other shallow intra-cratonic rifts in Sundaland. The intra-cratonic area of Sundaland in Central Kalimantan (in this case called the West Barito High, Kleibacker et al., 2015) was tested by drilling Nangka-1 well (Petcon Borneo-ConocoPhillips Palangkaraya, 2015). The well is a twin to an old Dutch well reported to have tested oil. Nangka-1 well encountered the Tanjung sands but with no hydrocarbons. Water was acquired on a sampling test. Long distance hydrocarbon migration (around 150-200 km) from the Barito Basin kitchen was prognosed for this prospect area. However, the prognosis does not work, it may have problem with long distance hydrocarbon migration or the kitchen itself.

Attention is also needed for exploration in northern part of the Bogor Trough of West Java. The area has been explored since the late 1990's and early 2000's by JOB Pertamina-Saga in the Greka Jatiluhur block but with no significant exploration activities. The area was then operated under a PSC by Bumi Parahyangan Ranhill and continued by Pan Orient Energy Citarum. Several exploration wells were drilled, including: Pasundan-1 (2007), Cataka-1 (2012, 2013), Jatayu-1 (2012) and Geulis-1 (2012). All of the wells targeted Late Miocene carbonate reefal build ups of the Parigi Formation along the northern slope of the Bogor Trough. No hydrocarbons were discovered. Some of the wells had mechanical troubles, and failed to reach the target, or no reservoir was encountered. The hydrocarbon prospectivity of the Bogor Trough is less well understood. However, the first Indonesia's exploration well drilled in the Bogor Trough at the northwest foot of Mount Ciremai in the Majalengka area, was located nearby surface oil seeps. The wells of Maja/Cibodas produced oil for a length of time. The oils were investigated geochemically and shown to be of a similar type with Jatibarang oil. The Bogor Trough is considered to contain source and reservoir debris from the Northwest Java Platform.

The intra-arc Ombilin Basin of Sumatra needs to update here because there was new exploration drilling in 2014-2015 (Sinamar-2). This well was drilled after twenty years of inactivity since the last well, South Sinamar-1, drilled by Apache Singkarak in 1994. The intra-arc Ombilin Basin was operated first by Caltex Singkarak (1981-1986). Caltex drilled one well Sinamar-1 (1983), testing gas at 13 MMCFPD and condensate at 300 BPD from two sandstone intervals of the Eocene to Oligocene Sawahtambang Formation. The area was then operated by Apache Singkarak from 1991-1994 who drilled South Sinamar-1 without testing. The well was indicated with hydrocarbon shows based on cuttings and log data. Since 2008, the area was operated by Radiant Bukit Barisan with the block name SW Bukit Barisan. Radiant appraised the Sinamar discovery by drilling Sinamar-2 in 2014. Four tests at Sawahtambang sandstones flowed gas at 0.34 MMCFPD only when the well was re-tested in 2005, it flowed around 3 MMCFGPD. Radiant plans to continue exploration in this area.

(2) West Sulawesi Offshore Exploration

West Sulawesi Offshore covers the eastern part of the Makassar Straits. Its western counterpart is called the Mahakam Offshore which has been explored since the late of 1960s. Many large to giant oil and gas fields have been discovered until the 1980's in the shelfal area. The deep water continuation of the basin started to be explored in the mid-1990's, where significant and large oil and gas fields have been discovered in the late 1990's and early 2000's.

Onshore West Sulawesi has been explored since 1980's promoted by the occurrence of numerous onshore oil and gas seeps. However, exploration has not been continuous or intensive, and was halted for long periods of time. No discovery has been made in this area after several wells were drilled. The offshore sector remained unexplored until 2006, after which the West Sulawesi Offshore was explored significantly (Figure 9). Several speculative seismic surveys were acquired and the Government of Indonesia offered numerous contract areas. The area attracted many contractors and they operated the PSCs from 2006 onward. They conducted exploration studies, acquired detailed 2D and 3D seismic data and other geophysical and geological data. Up to 2012, six operators (ExxonMobil Surumana, ExxonMobil Mandar, Marathon Pasangkayu, ConocoPhillips Kuma, Statoil Karama, and Talisman Sageri) drilled thirteen offshore exploration wells. One operator (Tately Budong-Budong) drilled two onshore wells in West Sulawesi. Satyana et al. (2012) and Satyana (2015) summarized the results of exploration and their implications on the current knowledge of the petroleum geology of the area. The location of wells can be seen on Figure 8.

The first well in the area, Rangkong-1, was drilled by ExxonMobil Surumana in 2009. The well targeted Eocene-Oligocene carbonate but did not encounter the main reservoir objective. Instead a pre-Eocene fractured volcanic with no hydrocarbon indications was found. Exxon did fluid inclusion studies of the volcanics and found traces of oil, dated as Quaternary generation - a delayed generation, maturity problem. Exxon moved to another block in the area, the Mandar Block, and drilled three wells: Sultan-1 (2009), Kris-1 (2010), and Kris-1 ST (2010). Sultan-1 found some gas during the logging runs, which was mostly biogenic in nature. Kris-1 and Kris-1 ST were dry holes due to tight reservoir and absence of reservoir, respectively.

Marathon drilled their first well in the Pasangkayu Block, Bravo-1 (2010) and then continued with Romeo-1 (2010, mechanical trouble), Romeo-B1 (2010, mechanical trouble), and Romeo-C1. The Bravo-1 and Romeo-C1 wells did not find hydrocarbons despite the presence of good quality Eocene-Oligocene carbonates. The wells encountered thick carbonate reservoirs, with 20-25% porosity. Pressures and fluid samples confirmed the primary objectives were wet. Preliminary analysis indicated that charging is the most likely failure mechanism, however, source presence and migration pathway issues cannot be ruled out. Limited or no source potential rocks were deposited within the low area prognosed as the kitchen to the west of Romeo. Whereas, the prognosed kitchen of Bravo may suffer from a lack of maturity due to thin overburden and inversion.

Statoil Karama drilled three wells in the deep water area targeting Neogene objectives deformed in faulted anticlines. The wells are called: Gatotkaca-1 (2012), Anoman-1 (2012), and Antasena-1 (2012). All of the wells were dry. The objectives showed poor reservoir qualities and no hydrocarbons were found. The wells were prognosed to penetrate faulted anticlines of inverted structures and charged by hydrocarbons generated and migrated from Paleogene sources. However, seismic sections show obviously that the structures of prognosed wells are thin-skinned structures and not inverted structures. The compressive deformation was only in the Neogene section, and did not involve the Palegene section. The presence of a decollement or detachment surface beneath the faulted anticlines is clear. Consequently, there was no hydrocarbon charging to the anticlines from the Paleogene source rocks. This was due to an absence of fault connection from Paleogene to Neogene, and the presence of a decollement surface which serves as a seal to block migrated hydrocarbons, if any, from the Paleogene entering the Neogene section. For this system to work, the Neogene section should contain their own source rocks. However, no significant source potential is found in the Neogene. Only poor Neogene reservoirs were found due to diagenetic changes of volcano-clastic sediments to clay rich sediments. In the Neogene, West Sulawesi onshore was dominated by volcanics and therefore the offshore area also received volcano-clastic deposits.

In the West Sulawesi onshore area, Tately Budong-Budong drilled two wells, LG-1 (2011) and KD-1 (2011) in the Lariang and Karama basins, respectively. The two basins are known to be rich in numerous oil and gas seeps. The source of oils and gas has been geochemically investigated and they originate from Eocene sources. The area was explored in 1970's and 1980's by Gulf and BP, and several wells were drilled with Miocene and Eocene sandstones as the targets. No discovery resulted from the previous wells, and the wells did not reach the Eocene objective due to high deformation. LG-1 found similar problem with the earlier wells. However, the KD-1 well did reach the Eocene section, but no reservoir rock was found. The Miocene target in KD-1 well had oil shows, but failed to produce hydrocarbons on MDT sampling.

Talisman Sageri drilled Lempuk-1 well in late 2011 in the South Makassar Basin. The well targeted a carbonate build up prognosed as Eocene in age. The location of the structure was in good position to be charged by hydrocarbons generated from a nearby low area considered to be the kitchen. The well penetrated good carbonate reservoir quality. However, only hydrocarbon shows were found. A breach of seal is considered as the main reason for an accumulation failure. However, the presence of bituminous hydrocarbons in some carbonate layers show low maturity or delayed generation from the adjacent kitchen area.

ConocoPhillips Kuma drilled the Kaluku-1 well targeting a structure prognosed as an Oligo-Miocene carbonate build up, beneath the offshore Neogene thin-skinned fold-thrust belt. When it was drilled, the target reservoir was found to be absent. Instead, a thick over-pressured shale was encountered. In fact, the "build up" structure was shown to be a seismic artifact due to pull-up of a high velocity seismic interval corresponding to a fold and thrust section. The well was then deepened, targeting the underlying Eocene package. When the Eocene section was penetrated at two depths, the well bled waxy oil over the shale shaker. The presence of oil in the Eocene was confirmed by MDT sampling. The Eocene sandstones have good to excellent reservoir qualities (average porosities 30 % and permeability 450-500 mD) despite having 10,000 to 11,000 feet of overburden thickness. Based on the analyses, the oils migrated from a nearby kitchen containing a shallow lacustrine source facies with 0.57-0.67% Ro maturity (Satyana, 2015). See Figure 9 for a schematic explanation.

Exploration activities from 2006 to 2012 in West Sulawesi Offshore provided us with lessons for further exploration in this area. The wells targeted Eocene-Oligocene carbonate build ups or Neogene siliciclastics. These targets are absent or almost devoid of hydrocarbons. The Kaluku-1 well proves that the Eocene sandstone is hydrocarbon-bearing in the deep offshore basin. The reason for so many dry wells here is not breached structures due to imperfect sealing as many operators considered, but rather the geochemical risks related to: no source in some low areas (low area is not necessarily a kitchen), delayed generation in certain kitchens (insufficient maturity), and blocking of hydrocarbon migration from Paleogene source rocks to Neogene structures due to thin-skinned tectonism. Satyana (2015) detailed the implications of exploration activities in the area, providing lessons for further exploration.

The Kuma Block oil discovery in Kaluku-1 well is very significant for the prospectivity of Paleogene objectives in the Makassar Straits (Figure 9). It is the first discovery of petroleum in an Eocene sandstone, horst block rift structure, in the Makassar Straits. The sandstones displayed excellent reservoir character with porosities as high as 30% and averaging 27%, despite a thick overburden of 10,000 to 11,000 ft. The oils are interpreted to have been derived from a source rock facies deposited in shallow lacustrine setting within the graben (syn-rift sequence). The source rock contained some terrestrial material shed from the horst block. The oils came from early generation with calculated Ro of 0.57-0.67%.

Petrophysical and geochemical analyses of Eocene sandstones and shales (detailed in Satyana, 2015) show good to excellent qualities. This will positively affect the regional prospectivity of Eocene objectives in the area. Shales deposited on horst blocks usually will have low organic preservation because of oxic conditions. However, geochemical analysis showed that the shales in Kaluku-1 have good to excellent quality. Even better quality source rocks will likely occur in graben areas, within the deep lacustrine system which remains unexplored. A source area such as this is considered to develop east of the Kaluku-1 discovery, where a thicker section is involved in thin-skinned tectonics. The thicker section will cause the onset of hydrocarbon generation to occur earlier, thereby providing more hydrocarbon charge volumes. Thicker sandstone reservoirs may also exist to the east of Kaluku-1, due to increased accommodation space for sand deposition. The Kaluku-1 discovery warrants further exploration in this area, focusing on the deep Eocene sandstone objective (Eocene horst block and syn-rift play).

(3) Mesozoic Australian Province Exploration

The discovery of the Tangguh gas field complex in the Bintuni Basin (Bird's Head, Papua), and the Abadi gas field (Timor Sea) in Jurassic sandstones of the Australian continental margin, triggered the search for additional hydrocarbons within a similar play. However, only exploration in the Kasuri Block to the south of the Tangguh field complex has proven to be a success, with several gas discoveries similar to those of the Tangguh complex (Asap, Merah, Kido gas discoveries).

In the early 2000's, exploration following the success of the Tangguh gas project was marked by drilling of three wells targeting Jurassic sandstones: Makiri-1, Aimau River Deep-1 (JOB Semirak), and Siganoi-1 (JOB Malagot). The three wells were dry, with only gas shows. Close to Siganoi-1 in an updip location, Total SW Bird's Head drilled the Anggrek Hitam-1 well in 2013, but again the well was dry. Continuation of the Jurassic reservoir fairway from the Tangguh field complex becomes the main issue.

Exploring for Mesozoic targets was also conducted by PetroChina Kepala Burung in the Salawati Basin. Based on seismic lines, the presence of pre-Cenozoic sediments are possible. Some existing wells completed in Miocene Kais carbonates geochemically show the contribution of hydrocarbons considered to be generated and migrated from pre-Cenozoic sources. Several wells were drilled in the Salawati Basin to explore for a Mesozoic target. Three such wells drilled during the 2000's are: Walio Deep (Walio-311), Jaya Deep-1, and Klabaru-1. However, none of the wells discovered hydrocarbons within the target section. The Mesozoic potential of Salawati Basin needs to be evaluated systematically to know its true potential.

Following the Abadi gas field success, one well was drilled by CNOOC in Southeast Palung Aru Block, called Sindoro-1 (2011). The well did not encounter a good and thick enough Jurassic reservoir equivalent to the Plover sandstone of Abadi. The reason for the absence of thick reservoir was that the well was located outside the main fairway of Jurassic deposition along the Mesozoic rifted graben of the Australian continental margin.

The Mesozoic rifted graben continues to the Semai Area to the southwest of the Bird's Head and southeast of Seram Island. New speculative seismic lines were acquired in this area followed by the offering of five contract areas, Semai I to Semai V, since 2008. The working areas were immediately picked up by companies. The first deep well drilled in Semai area was Lengkuas-1 (Murphy Semai II, 2010). This well became the deepest well in Indonesia, with TD at 21,320 ft in the Late Triassic. The well targeted Jurassic and Paleocene sandstones and Miocene carbonate objectives. The well penetrated the Miocene carbonate with no shows. The Late Jurassic shaley sandstones were recorded with gas peaks, and thin tight Early Jurassic sandstones were also found. No Paleocene sandstones were encountered. The second well, Serai-1 was drilled in 2014. The well encountered 58 ft of Early Jurassic sandstone with 9.6% porosity, but water-bearing. The third well, Bawang Putih-1 (2014) encountered Jurassic sandstones but they were very tight with some alteration into metasandstones. Murphy totally relinquished the Semai II area. Another deep well drilled in the Semai area targeting Jurassic sandstones was Andalan-1 drilled by Hess Semai V. The well penetrated the Jurassic and Triassic section, with 30-60 ft of Jurassic sandstones which were tight and water-bearing. Based on these four wells, it appears that the main risk for exploring the Semai area relates to the presence of good Jurassic sandstone reservoir and source. Original sand deposition in this area is considered at the far distal end compared to those in the Tangguh and Abadi fields. The distal area will also have increased risk of organic matter presence and preservation due to a more oxic environment. The sandstones in Lengkuas also deteriorate due to overburden thickness in excess of 17,000 ft. A consideration that the Jurassic sandstones in the Semai area were deposited as turbidites coeval with exposed sandstone provenances updip during lowstand sea levels duirng Jurassic times could be an alternative model for further evaluation.

Australian Mesozoic exploration was also conducted in the Buton area, an Australian microcontinent which collided with SE Sulawesi in Miocene times. After fifteen years without exploration (since 1992), Buton Island was again explored by two companies, Japex Buton (2007-2013) and Putindo Bintech Buton I (2008-present). Exploration studies, geological and geophysical surveys were conducted before two wells were drilled. Japex drilled Benteng-1 (2012), which targeted Cretaceous Tobelo carbonates. The well did not reach the target due to severe deformation issues that could not be resolved. The well was abandoned with some oil shows extracted from fractured carbonate of Miocene Tondo Formation. Putindo drilled EK-1 in 2012-2013, targeting Miocene Tondo carbonates/sandstones (Satyana et al., 2013). The well did not encounter significant hydrocarbons, with swabbed water and oil shows. Putindo is drilling a core hole called LBL-1 to study the stratigraphy of its working area.

Presence of asphalt deposits shows that a working petroleum system exists in the Buton area. However, six exploration wells (dry, some with oil shows) drilled on Buton Island from 1970 to 2013 show that locating oil accumulation is not easy. Most failures have related to complicated structures that could not be imaged with existing seismic lines. Three wells did not reach the main objectives due to the targets being deformed and too deep beyond prognosis. Two wells were drilled in unsealed structures due to erosion. Future exploration should locate simple structures with intact seals. Improvement of seismic data is required to have better seismic imaging.

(4) Lower Paleozoic Australian Province Exploration

For the first time in Indonesia, the Lower Paleozoic objectives from the Devonian to the Cambrian became the target of exploration. This occurred during 2006 to 2012 when ConocoPhillips acquired two blocks in the shallow Arafura Sea to the west of Papua namely Amborip VI (2006) and Arafura Sea (2011). ConocoPhillips based the exploration in this area on Paleozoic petroleum system developing in onshore Australia to the Arafura Sea. Bradshaw et al. (1997) showed that Lower Paleozoic Larapintine Supersystem is proven in onshore Australia to the Arafura Sea. Cambrian Larapintine occurs in the Arafura Basin. Ordovician Larapintine occurs in central onshore Australia and in the Canning Basin. Late Devonian Larapintine and Early Carboniferous Larapintine occurs in the Canning Basin and in the Petrel Sub-basin, Bonaparte Basin.

In the Australian territory immediately south of the Amborip area across the Arafura platform, a number of wells were drilled in what is called the Goulburn Graben in the southern part of the Arafura basin. One well, Arafura-1 (Petrofina, 1983) encountered in excess of 400 m of live oil shows in Devonian sandstones and Ordovician dolomites as well as possible source rocks in the Devonian and Cambrian. The wells in the Goulburn Graben provide supporting evidence for the presence of a Paleozoic petroleum system in the Indonesian part of the Arafura basin (Miharwatiman et al., 2013).

ConocoPhillips drilled Aru-1 well (2011) in Amborip VI and Mutiara Putih-1 (2011) in the Arafura Sea Block (Figure 8). Miharwatiman et al. (2013) reported the prognosis and results of these wells. The primary reservoir objective of Aru-1 was Devonian clastics, while the Mutiara Putih-1 primary target was Permo-Carboniferous clastics. The two wells were drilled on large four-way dip anticlines on each block. The Aru-1 post-drill results showed that the Tertiary and Cretaceous sections were encountered as anticipated, however the predicted Silurian-Devonian was missing. Below the base Cretaceous unconformity, Late to Mid Ordovician sediments were encountered, consisting of massive dolomite, dolomitic sandstones and shales with no reservoir potential and no hydrocarbon indications. The Mutiara Putih-1 well confirmed that the Paleozoic Permian was present, however the Carboniferous through Devonian section was absent in the Arafura Sea Block. The well penetrated a thin Tertiary section unconformably overlying the Permian objective, and directly into Ordovician intervals below. The Permian section includes intervals of clean sandstones with some fluorescence in cuttings and some dead oil occurs as pore-filling and pore-lining materials.

The well results showed that maximum burial and the amount of uplift was greater than originally anticipated. Both wells, the Aru-1 and Mutiara Putih-1 reached TD in the Mid (?) - Late Ordovician section. The entire Silurian, Devonian and Carboniferous were absent. It is estimated that the Aru structure had experienced approximately 15,000ft uplift and erosion, and the lower Paleozoic petroleum system was not preserved. Understanding the burial history of Paleozoic (older) basins is critical to the source and more importantly the "preservation" of reservoir and the hydrocarbons (Miharwatiman et al., 2013).

(5) Neogene Pacific Province Exploration

The Pacific Province is defined, in this case, as the area to the north of the Sorong Fault, and the area to the north of the Central Ranges of Papua. The area includes: Halmahera, Kofiau, Cenderawasih Bay, and the northern part of Papua. Geologically, the area has no affinity with Australian geology. Most of the Pacific Province contain Neogene sediments that shed from a surrounding uplifted provenance which was rapidly buried. Some carbonate build ups may have developed.

McAdoo and Haebig (1999) provided the petroleum geology of Northern Papua basins. The bains contain over 25,000 feet of Tertiary-aged clastic and carbonate sediments in several localized depocenters or sub-basins, most notably the Waropen, Teer River and Waipoga "deeps" and an intermontane sub-basin known as the Meervlakte. Rapid subsidence has created asymmetric basin fills dominated by turbidites. Potential reservoir distribution across the depocenters appears to be problematical with good quality turbidite reservoirs being concentrated near depocenter margins. Large reef complexes are evident. There is evidence of ample terrigenous-derived kerogens to serve as a potential petroleum source. An apparent low thermal gradient of 1.67°F per 100 ft. in the basin extends source maturity to considerable depth.

The first documented report of a hydrocarbon occurrence on the northern Papua coast dates from 1916 when an exploration survey discovered a large live oil seep along the Teer River. The Teer River Seep occurs in alluvium as a shallow pool 10 feet wide and consisting of a perpetually fed flow of light, orange-brown oil of 38 deg API gravity. Gas is observed to bubble through the oil pool. Gas analysis indicates it contains mostly methane with some heavier hydrocarbons. Since the 1950's, 12 petroleum exploration wells, have been drilled including one stratigraphic test. The drilling resulted in four dry holes, two gas discoveries (Niengo-1 and R-1), and four wells were abandoned before reaching target depth due to encountering severe overpressure.

After decades without exploration drilling in this region, a new exploration well was drilled by Niko Resources and partners in the Cenderawasih block, called Elang-1 (2013) (Figure 8). The well targeted Oligo-Miocene a carbonate build up of the Darante Formation. Locally, throughout history of the North Papua Basin, carbonate deposition was widespread although likely confined to highs and shelf breaks during periods of low clastic influx. Unfortunately, the well encountered tight reservoir.

Niko Resources explored another area in this province, namely the Kofiau area between Misool and Halmahera Islands. The area is crossed by the Sorong Fault Zone. To the south of the fault is a continental portion of the Bird's Head occupied by Misool Island. To the north is the Kofiau area where very thick Pliocene Klasaman sediments were rapidly deposited partly as turbidites. Niko showed that the area contained many oil and gas seeps based on multibeam and sea bed coring. Two exploration wells were drilled, Ajek-1 (2012) and Elit-1 (2013).

Ajek-1 encountered thin reservoir sandstones within a mostly shaley section. The objectives at Elit-1 were penetrated, with sandstones containing sub-commercial hydrocarbons.

South Halmahera Basin has been explored by Statoil Halmahera since 2011. New 2D seismic lines were acquired by speculative surveys between 2007 and 2010. No exploration well has been drilled in the Halmahera area. The main objective of the Halmahera Basin is similar to the producing Miocene Kais reefs in the Salawati Basin. New seismic lines indicate the presence of these objectives in South Halmahera Basin. However the tectonic setting of the two basins is different. Halmahera basin has Pacific affinity whereas the Salawati Basin has Australian affinity. This should be taken into account when exploration continues in the South Halmahera Basin.

CONCLUSIONS

1. To provide the lessons for future exploration in Indonesia, fifteen years of exploration activity, from period of 2000 to 2015, were reviewed. These "where from" activities provide lessons, both in cases of success and failure, for us to plan on "where to" go for future exploration.

2. Opening the era of 2000's, the petroleum industry in Indonesia was marked by the application of a new Oil and Gas Law (Law No. 22 Year 2001). The Law dismisses the role of Pertamina as the governmental executive body in the oil and gas business, replaced by BPMIGAS (later SKK Migas), and the Directorate of Oil and Gas-Ministry of Energy and Mineral Resources as a regulatory body.

3. Investment in petroleum exploration in Indonesia showed high performance during this period as can be seen by a significant increase of contract area licensing, including both conventional and unconventional hydrocarbon contracts. The number of contracts increased from 110 areas in 2003 to 312 areas in 2015. However, this has been followed by a decline since 2012 due to global lower oil price.

4. Indonesia was the leader in the number of 2D and 3D seismic surveys in Southeast Asia during the period. In general, around 25 to 30 2-D seismic surveys were carried out annually from 2001-2015. This dropped rapidly in 2015. As for 3D seismic surveys, mostly around 10 to 15 3D seismic surveys were carried out annually from 2001 to 2010, and increased significantly in the last five years from 2011 to 2015.

5. Almost one thousand exploration wells (974) were drilled from 2002 to 2015, consisting of 617 onshore- and 357 offshore wells. From the number of wells, 676 wells are NFWs of which 310 wells discovered hydrocarbons, resulting in NFW technical success ratio of 46 %. New technical resources from 2000 to 2015 amount to 18,500 MMBOE in place.

6. Significant discoveries during 2000-2015 in Western Indonesia can be grouped into these play concepts: (1) Paleogene deeper sections/syn-rift sections of Sumatra, West Java, West Natuna Basins, (2) pre-Cenozoic fractured basement of South Sumatra, West Java, East Java Basins, (3) Oligo-Miocene carbonate build ups of East Java and Upper Kutai Basins, (4) Mio-Pliocene deep-water turbidites of North Makassar and Tarakan Basins, and (5) Mio-Pliocene growth-faults of delta progradation of Tarakan Basin. Significant discoveries during 2000-2015 in Eastern Indonesia can be grouped into these play concepts: (6) Australian Jurassic passive margin sediments, and (7) carbonates-reefal build ups or fractured carbonates (Miocene and Jurassic).

7. During 2002-2015, 388 wells were dry. The wells were located in various places and drilled using various play concepts, including: (1) exploration immature areas of Western Indonesia (forearc basins of Sumatra and Java, intra-cratonic basins of Sundaland, Bogor Trough), (2) West Sulawesi Offshore, (3) Mesozoic and (4) Lower Paleozoic Australian provinces, and (5) Neogene Pacific province. These "failure" cases have provided lessons for better future exploration.

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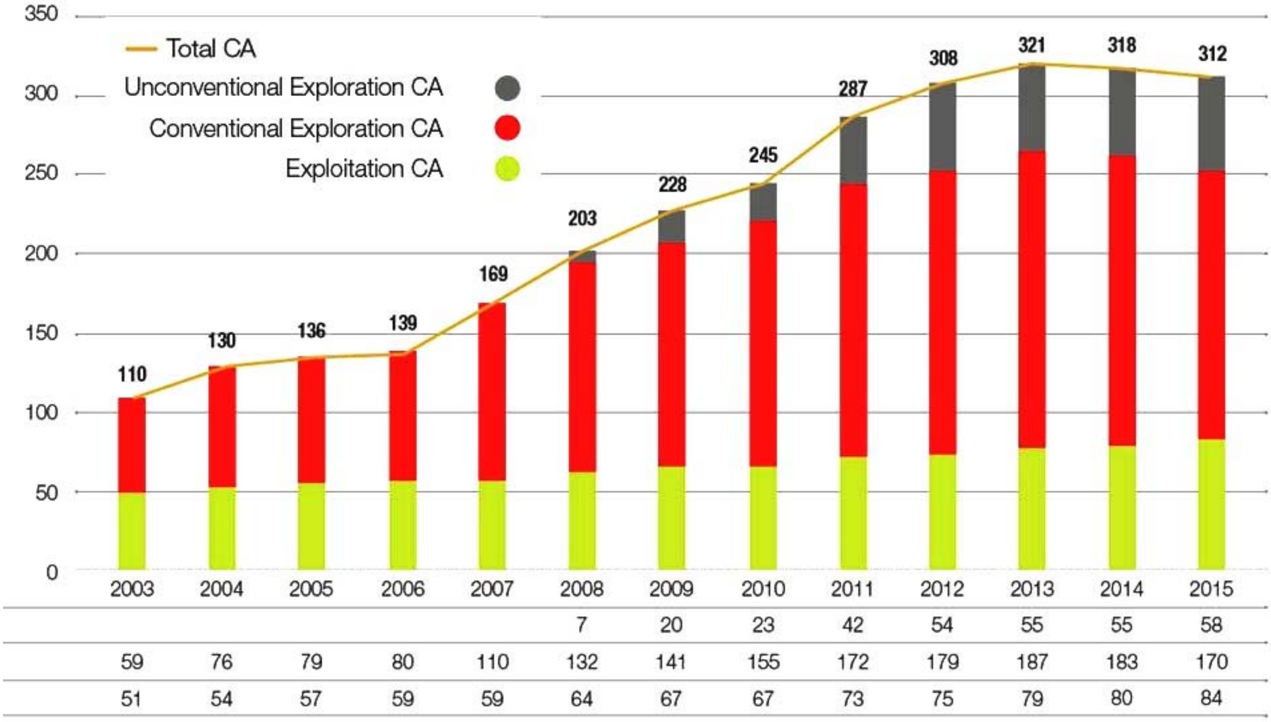
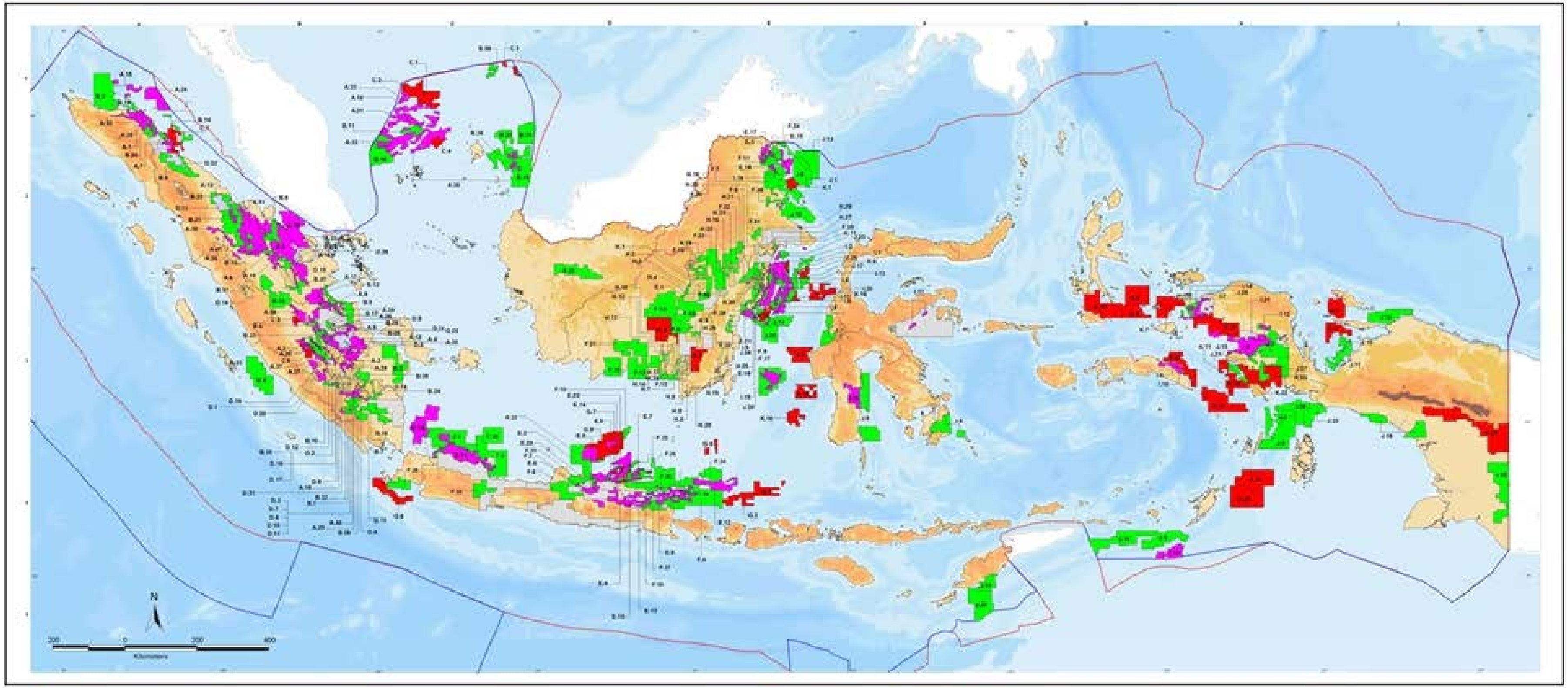


Figure 1 - During the period of 2003 up to 2015, after the application of the new Oil and Gas Law 22/2001, the addition of new contract areas (CA) was very significant. This addition also included the contract areas for unconventional hydrocarbons (coal bed methane-CBM since 2008 and shale gas since 2013). Note that most of the addition of contract areas during the period were for exploration areas. The addition of exploitation areas during the period were far lower than that of exploration.

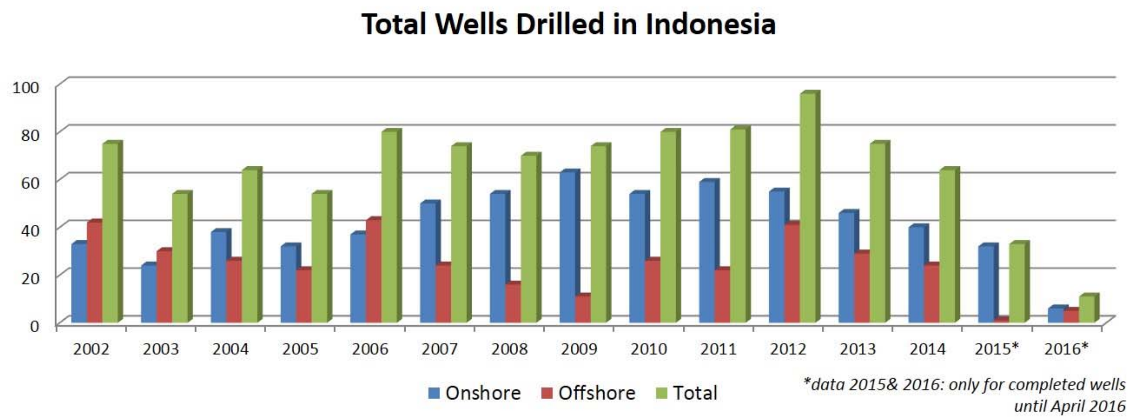
Distribution of Contract Areas in Indonesia (June, 2016)



Legend: *CA – contract area*

- Exploitation CA
- Exploration CA (conventional)
- Exploration CA (CBM)
- CA on termination process (CBM)
- Exploration CA (shale gas)
- CA on termination process (conventional)

Figure 2 - The current status (June 2016) of the contract area distribution in Indonesia. Currently there are 85 exploitation areas, 113 conventional exploration areas, 45 CBM exploration areas, 5 shale gas exploration areas, 6 CBM areas for termination, and 38 conventional areas for termination



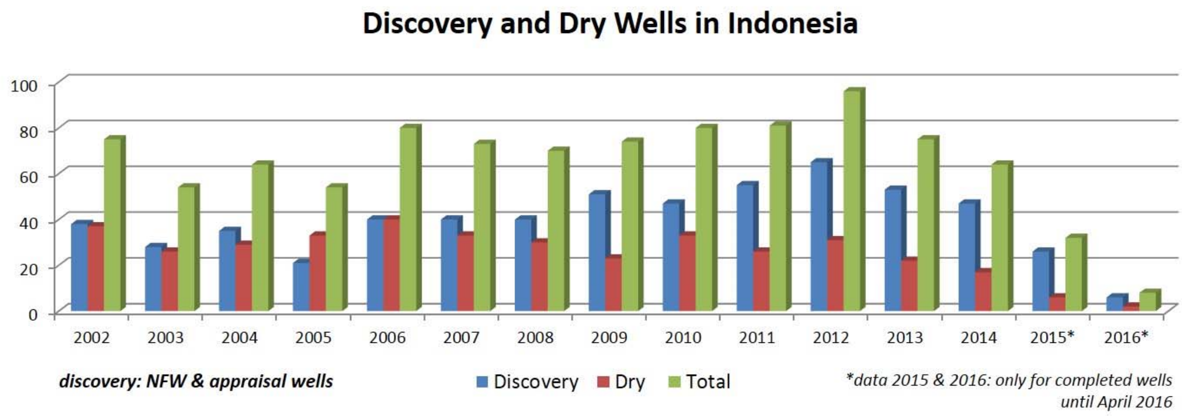
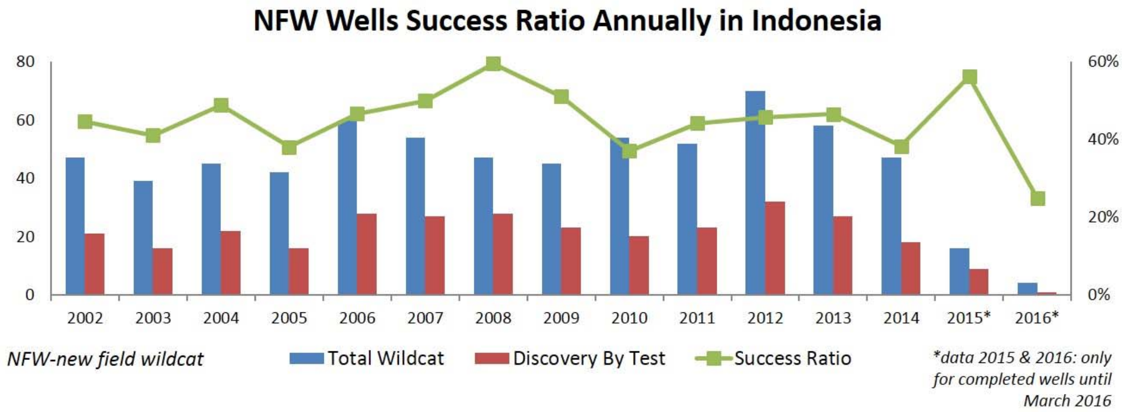


Figure 3 - Above –Total exploration wells drilled in Indonesia 2002-April 2016 located onshore and offshore. Below – Discovery (NFW and appraisal wells, oil and/or gas) and dry wells in Indonesia in the same period.



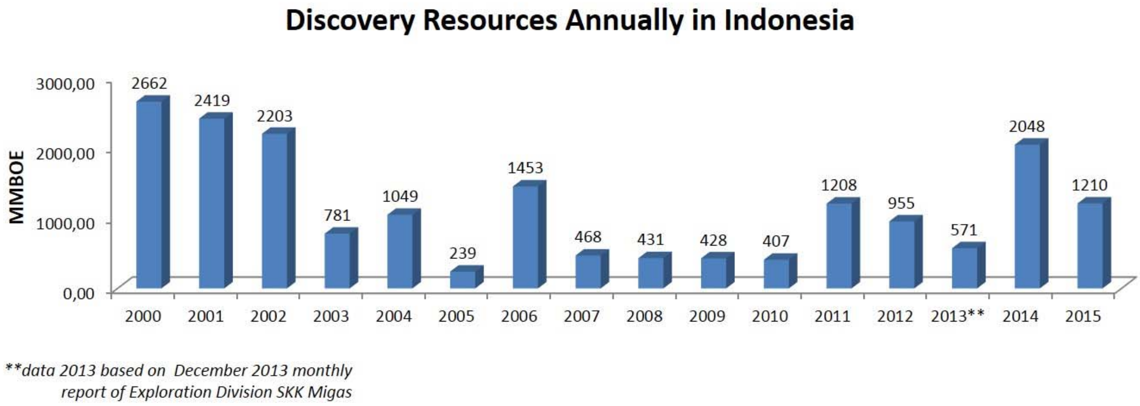


Figure 4 - Above – Success ratio of NFW wells in Indonesia, period 2002-April 2016. Below – New resources discovered in Indonesia, period 2000-2005. Total equals 18.5 billion barrels oil equivalent

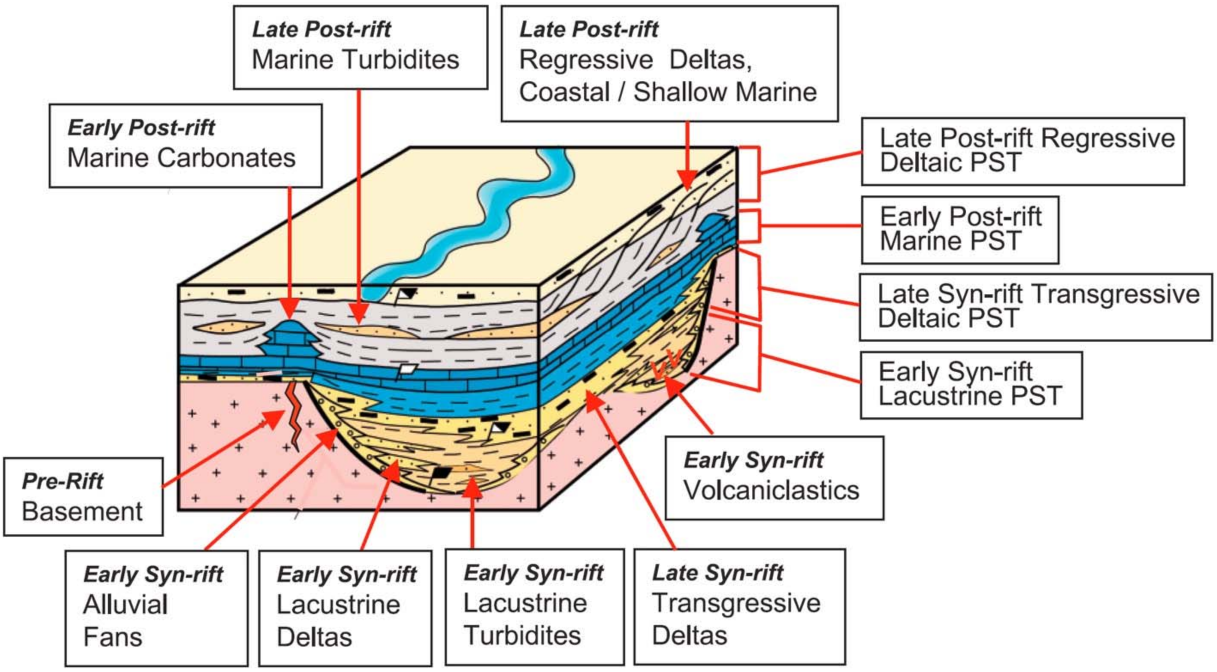


Figure 5 - Hydrocarbon discoveries in Western Indonesia during 2000-2015 occurred in reservoir plays belonging to the four petroleum system types (PSTs) for Southeast Asian Tertiary rift basins proposed by Doust and Sumner (2007). The discoveries can be grouped into these play concepts: (1) Paleogene deeper / syn-rift sections of Sumatra, West Java, West Natuna -*early syn-rift lacustrine and late syn-rift transgressive deltaic PSTs*, (2) pre-Cenozoic fractured basement of South Sumatra, West Java, East Java Basins –*pre-rift basement PST*, (3) Oligo-Miocene carbonate build ups of East Java and Upper Kutai Basins –*early post-rift marine PST*, (4) Mio-Pliocene deep-water turbidites of North Makassar and Tarakan Basins –*late post-rift marine turbidites*, and (5) Mio-Pliocene growth-faults of delta progradation of Tarakan Basin –*late post-rift regressive deltaic PST*.

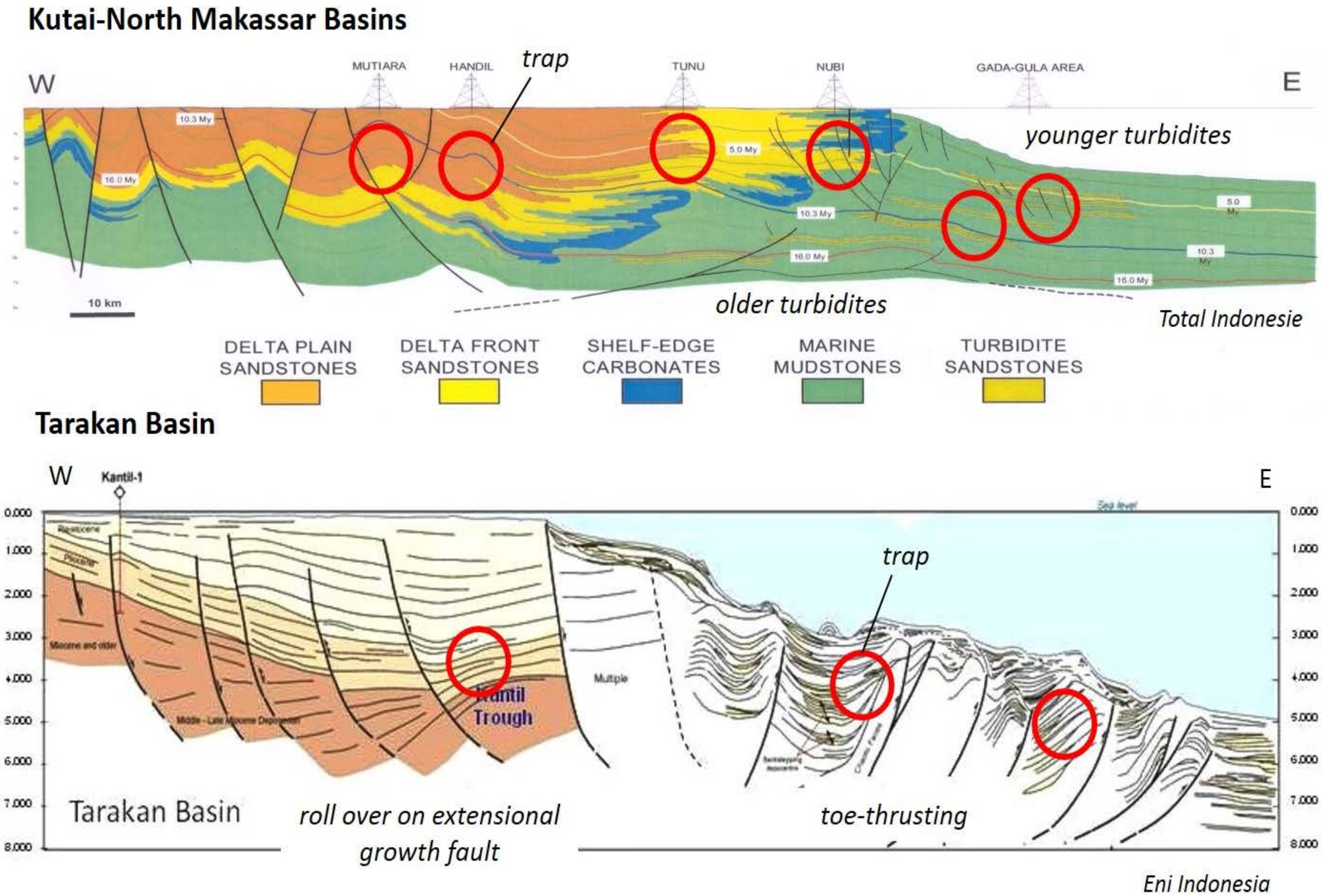


Figure 6 - Cross sections showing play types of discoveries from 2000-2015 in the Kutai Basin-North Makassar –Mio-Pliocene deep-water turbidites (above) and in the Tarakan Basin - Mio-Pliocene growth-faults of delta progradation (below).

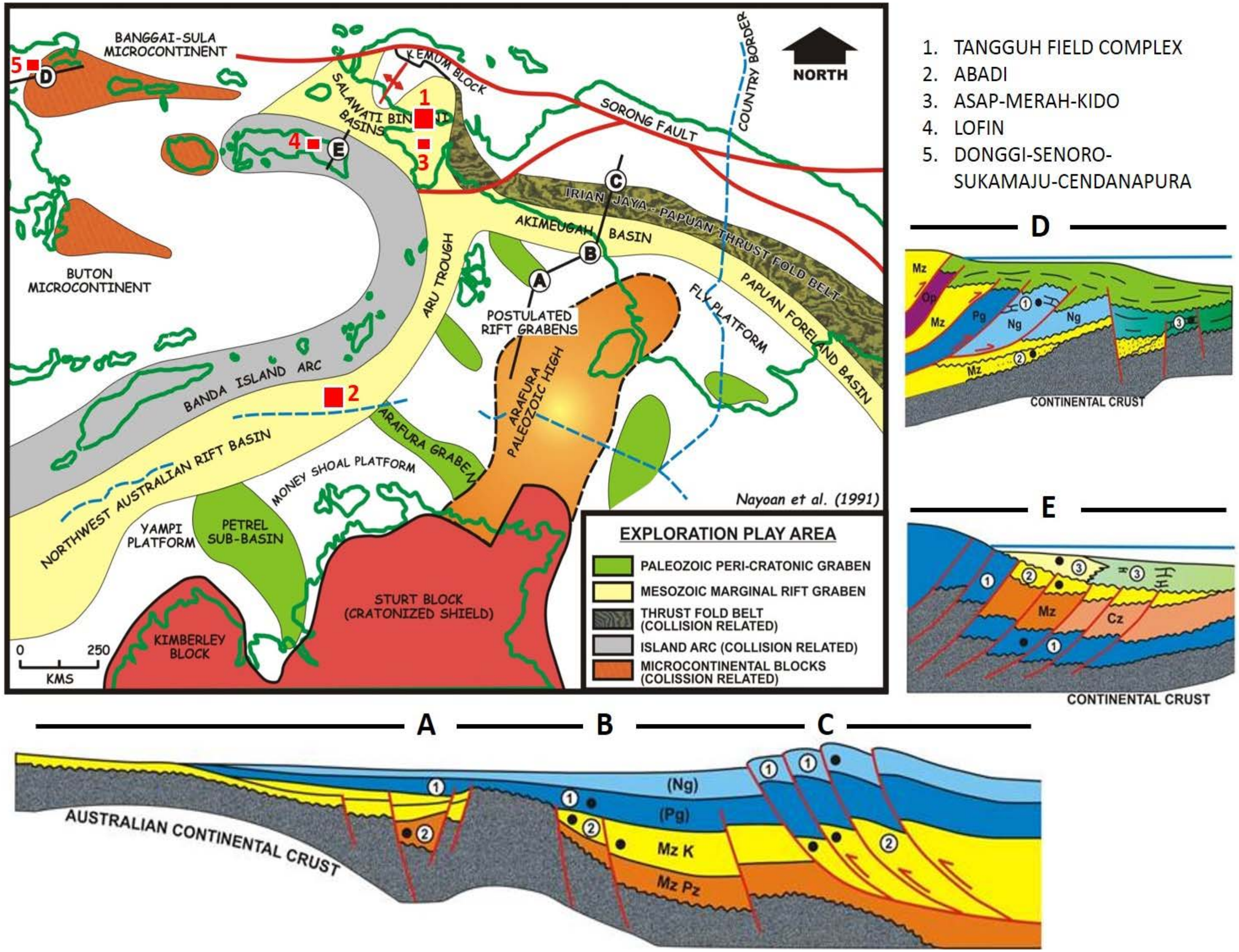


Figure 7 - Significant gas discoveries in Eastern Indonesia (numbers 1 to 5) in 2000-2015. The discoveries are plotted on the play types map of Eastern Indonesia (modified after Nayoan et al., 1991).

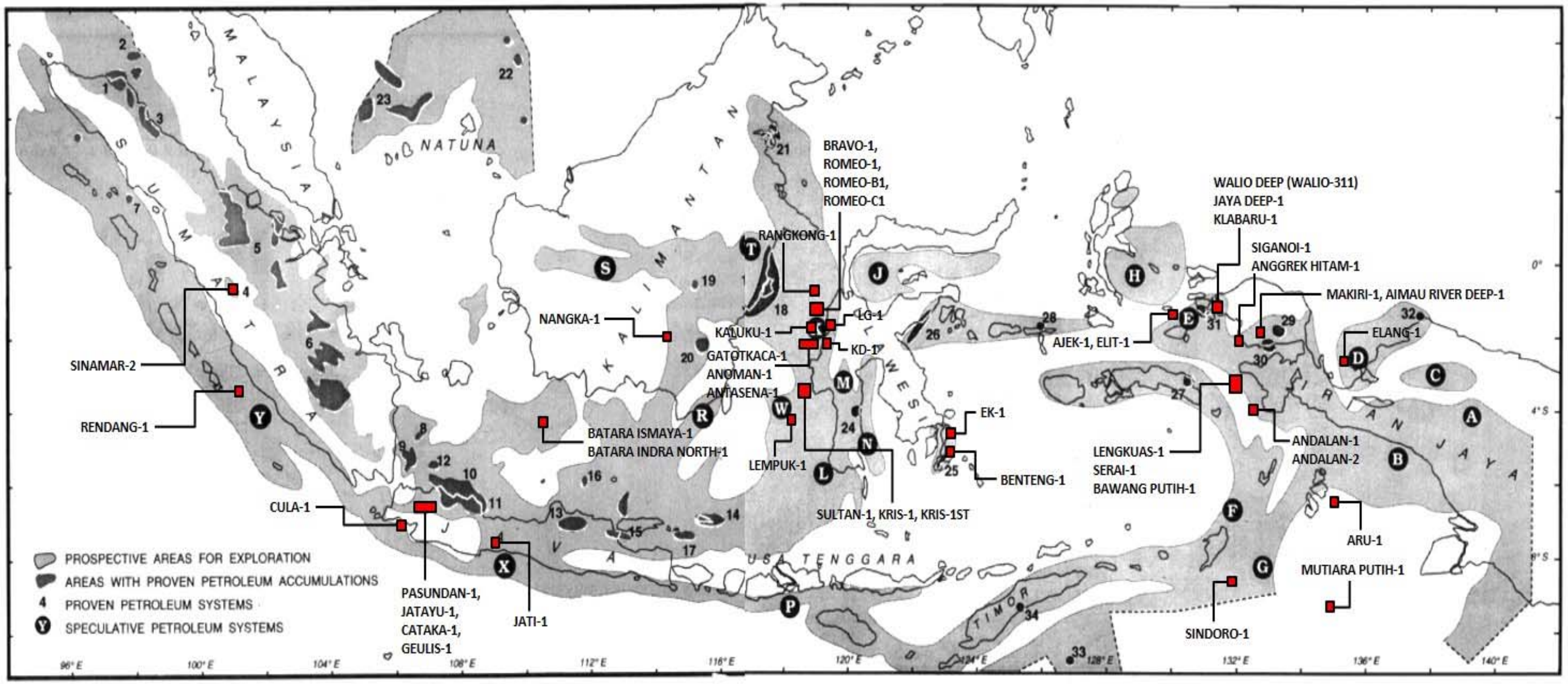


Figure 8 - Significant exploration wells in Indonesia during 2000-2015, especially in immature and frontier areas. All of the wells are dry, except: Sinamar-2 – Ombilin Basin (tested small amount of gas at Oligocene Sawahtambang sands), Jati-1 –Banyumas (tested small amount of gas and condensate at Mid-Miocene Penosogan sands, sourced by Eocene coaly shales), Kaluku-1 –West Sulawesi Offshore (sampled shallow lacustrine oils in Eocene sands), Sultan-1 (sampled small amount of gas, partly biogenic in Eoc-Oligocene carbonates), Benteng-1 –Buton (tested small amount of gas and condensate in Miocene Tondo carbonates). The wells are grouped into exploration trends of: Western Indonesia Immature (forearc Sumatra and Java, Bogor Trough West Java and intra-arc Sumatra, intracratonic Sundaland), West Sulawesi Offshore, Mesozoic Australian Province of Outer Banda Arc and Collision, Lower Paleozoic Australian Province of Arafura Sea, and Neogene Pacific Province of North Papua and North of Sorong Fault. The basemap shows hydrocarbon proven and prospective areas (basemap from Howes and Tisnawijaya, 1995).

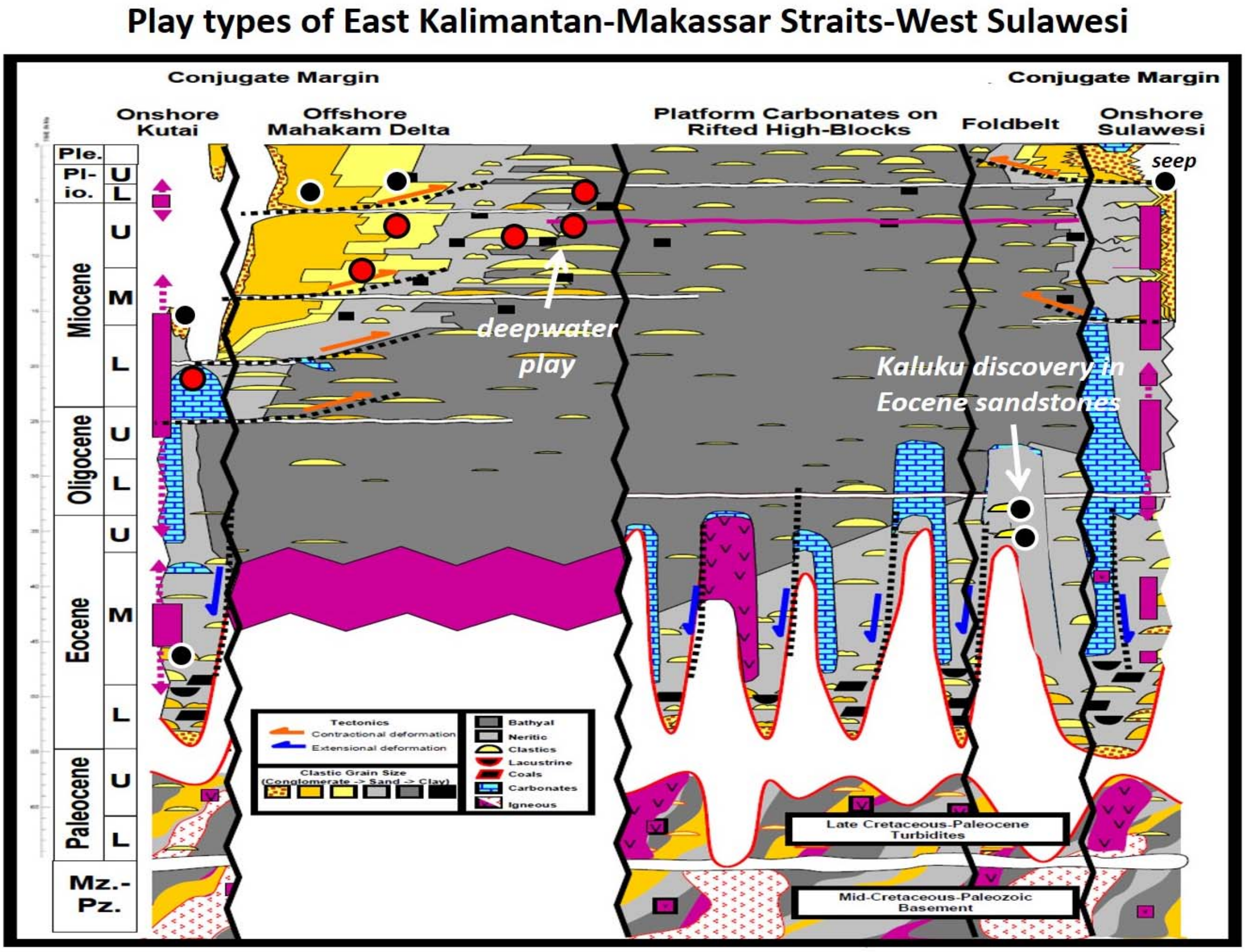


Figure 9 - North Makassar chronostratigraphic section, petroleum occurrences, and plays from Kutai Basin, western and eastern parts of the Makassar Straits, and onshore western Sulawesi. Petroleum in Mahakam Delta and its deep-water facies are very prolific, all in Miocene and Pliocene sections. Play type of Eocene section is proven only in West Sulawesi Offshore in rifted basement where the Kaluku discovery occurred on horst block, with active source in graben. All objectives in West Sulawesi Offshore younger than Eocene for carbonates and sandstones were dry. In onshore western Sulawesi, numerous oil and gas seeps occur, sourced by Eocene coaly shales (modified after Bacheller III et al., 2011).