ORAL PRESENTATION

Day 2: 4th April 2019

Session 6: Indonesia Revisited #1 - Sumatra

Chairs: Andy Butler – SundaGas, Nico Bianchi – RISC

10:45	Extended Carbonate Play Revealed by High Quality New 3D data, Deep Water Offshore North Sumatra Basin	Alit Ascaria	REPSOL
11:10	Challenging the Existing Paradigm: A Case for Dual Petroleum System Operation in the Central Palembang Sub-Basin, South Sumatera Basin, Indonesia	Welly Ramadan	Mandala Energy
11:35	Uncover the Overlooked Gumai Play Potential at Jabung Betara Complex – Indonesia: A Best Case Study Of Gas While Drilling Classification In Finding the New Pays	I Gusti Agung Aditya Surya Wibawa	PetroChina International
12:00	Sumatra Deep Basin Gas and Meeting Indonesia's Growing Gas Demand	Jerry Sykora	Canadian International Energy

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ORAL PRESENTATION

Extended Carbonate Play Revealed by High Quality New 3D Data, Deep Water Offshore North Sumatra Basin

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INTRODUCTION

The key success for exploration plays in the North Sumatra basin are basement structural highs with carbonate build-ups encased with source rock and blanketed with good seal. This play type has been proven by the Arun gas discovery with 16 TCF gas and condensate. Hydrocarbons within the North Sumatra Basin are mainly produced from both clastic and carbonate reservoirs of Miocene age (i.e. the Peutu / Belumai / Baong and Keutapang Formations). The basin exploration is very mature in the shallow water and onshore, but not yet in the deeper offshore. New data is needed, and 3D seismic acquisition was conducted in 2017 in the offshore Andaman III block. At least four exploration plays are identified in Andaman III: Play 0, Late Eocene-Oligocene carbonate; Play 1, Oligocene clastic; Play 2, Miocene carbonate and Play 3, Mio-Pliocene thrust clastic (Figure 1). The objective of this paper is focused on Play 0 of the Late Eocene-Oligocene carbonate Tampur Formation and is compared to the Arun field of play 2.

The Arun gas discovery reservoir consists of stacked bioclastic carbonate shoals with foraminifera, red algae and scattered coral patch reefs. This Peutu Formation thickens from less than 50m to over 300m over Early Miocene highs and the closure is formed by the depositional topography blanketed by the Baong Shale. Early finds of Peutu fields followed in 1972 at Alur Siwah, South Lho Sukon-A and B, Paseh and offshore at NSB-A (Maliki and Sonowari, 1990; Clure, 2005). However, not all basement highs have carbonate buildups (Caughey and Wahyudi, 1993). Exploration failures include Miocene structures that were too high in their paleo environment and therefore bald, or not high enough and therefore covered by syn-rift siliciclastics. The Pergidatit Platform in the central part of the Tamiang Deep between the Alur Siwah and Langsa Platforms has only carbonate mudstones and apparently was too deep for carbonate sedimentation during the Early Miocene and was subsequently drowned by siliciclastics of the Belumai Formation. In contrast, the Ibu Horst, the northern extension of the Langsa Uplift was too high, and the Peutu Formation is very thin and locally eroded (Figure 2). Similarly, part of the Arun-Cunda High was uplifted and the Peutu Formation was partly eroded (Wilson, 2002) reducing its reservoir potential. A key factor for carbonate reservoir is thus the timing of uplift and the relation to relative sea level.

The late Eocene-Oligocene Play 0 in Andaman III shows a similar structural setting to other early Miocene build-ups according to basin restorations, with clear carbonate growth over structural highs (Figure 3).

TECTONIC AND DEPOSITIONAL HISTORY

The structural history of the North Sumatra Basin throughout the Tertiary period can generally be divided into the Paleogene and Neogene tectonic phases. Initial tectonic activity during the Paleogene began in the Late Eocene, when the North Sumatra Basin was subjected to crustal extension as a result of collision between the Indian Continent and the Eurasian Plate (Daly et al, 1987), resulting in the formation of pull-apart "rift" sub-basins with a dominant north-south structural orientation. This created the typical rift patterns of high horsts and low grabens during Late Eocene through Oligocene. The sediment supply was from the west, filling the grabens with siliciclastic sediments, known as the Meucampali Formation, which unconformably overlies the pre-Tertiary basement. Further east was a broad shelf carbonate platform of the Tampur Formation, whilst in the

Andaman III area the Tampur carbonates are formed on isolated highs alternated with the deep water shales (Figure 4). Collision and subduction decelerated in the Early Oligocene and the former extensional regime changed to compression, resulting in basin inversion that is expressed by a local uplift and local unconformity over Eocene sediments. During the Late Oligocene rift, fault reactivations occurred along pre-existing lines of weakness of Early Oligocene faults (Sosromihardjo,1988). This uplift placed the carbonates (the Tampur Formation) in structural high positions. In the meantime, the basin depocentres (grabens) provide loci for the younger, fluvio-continental siliciclastic deposition of the Parapat / Bruksah Formations. This was followed in the Late Oligocene by marine incursion and deposition of the Bampo shale, which in troughs shows very thick deposits of euxinic shale. The modified stratigraphy chart has been applied in western NSB based on surrounding wells and detailed seismic interpretation (Figure 5).

HIGH QUALITY NEW 3D

New 3D seismic was acquired In November 2017 within the Andaman III block, covering 3175 km^2 of full fold data. The new methodology (CLA, Continuous line acquisition) comprised a full fold of 134 nominal fold, 10 streamers, broadband, 2ms sample rate and the very small of bin size: 6.25 m x 18.75 m. In-house 3D-PSTM seismic processing with Innovative workflows and proprietary algorithms and software applications, were designed, tested and successfully implemented. Adding a geologically driven approach and a very close interaction with interpreters to this mix of experience, edge technology and innovation, made for effective timing and the result is high quality 3D seismic data.

CARBONATE RESERVOIR

The carbonate seismic facies for the interpreted carbonate succession in the Andaman III area is marked at the base by a high amplitude and continuous reflector that would separate the main target from an igneous / metamorphic basement (Figure 6). The inferred top carbonate is positioned at a reflector that varies in amplitude laterally (from high to low) and that is interpreted as a contact with the overlying seal which, at least near the uppermost part of the carbonate, shows onlap terminations with the latter. A clear thickness change is seen in the target in a north - south direction (thicker northward and thinner southward) coinciding with a topographic high. The seismic character within the inferred carbonate mound reveals higher reflectivity and parallel-to-basement or chaotic reflectors and thickening strata, whereas the deeper area (southward) exhibits much lower reflectivity and continuous parallel-to-basement reflectors. Within the target, large parts of the thicker section show faulted blocks and numerous small faults that may indicate intense fracturing. Based on the seismic patterns and the geological information, the depositional environment is a shallow-water carbonate ramp deposited on a structural high during the Eocene-Oligocene (Figure 7). The inner ramp facies are probably benthic foram bioclastic packstone interbedded with red algae bioclastic packstone in a high energy shoal setting, based on contemporaneous analogs, while the profundal facies are probably marls and shale. It is difficult to evaluate the diagenetic processes that could affect the carbonate reservoir quality with the current dataset (seismic and regional data). The picked seismic interval velocities in the main carbonate mound are approximately 3200 m/s, and the overburden shale approximately 2600 m/s. The velocity of the carbonate mound is similar to that from Miocene carbonate reservoirs (Peutu Fm) with 15-25% porosity within the same basin (Hinton, 1987). This suggests abundant pore space in the reservoir. The main analogues for this reservoir are the Arun field, NSO, and also the Malampaya gas field in North Palawan, Philippines.

The profundal facies can potentially act as source rock. This source rock has been observed and assumed in various locations in the area, for example: Glagah-1, Benggala-1, and indirect evidence at Peusangan C-1 and Langgun Timur-1. Basin modelling suggests that this potential source rock is mature at present day and capable of expelling hydrocarbons. Timing is favourable for the carbonate build-up prospect and migration routes are short from surrounding mature source rock (figure 8).

CONCLUSION

- Four exploration play types are identified in the Andaman III block with new 3D seismic data: Play 0, Late Eocene-Oligocene carbonate; Play 1, Oligocene clastic; Play 2, Miocene carbonate and Play 3, Mio-Pliocene thrust clastic.
- Based on the seismic patterns and the geological information, the depositional environment is a shallow-water carbonate ramp deposited on a structural high during the Eocene-Oligocene.

- The main exploration play in the Andaman III block is Late Eocene-Oligocene carbonate build-ups on basement highs surrounded by marine shale. The 3D seismic mapping shows a very robust structure of the carbonate build-up prospect, and the quality of the new 3D seismic is excellent, which has enabled detail geological interpretation.
- The identified carbonate play in the deeper water Andaman area will unlock the exploration potential in the western North Sumatra Basin.

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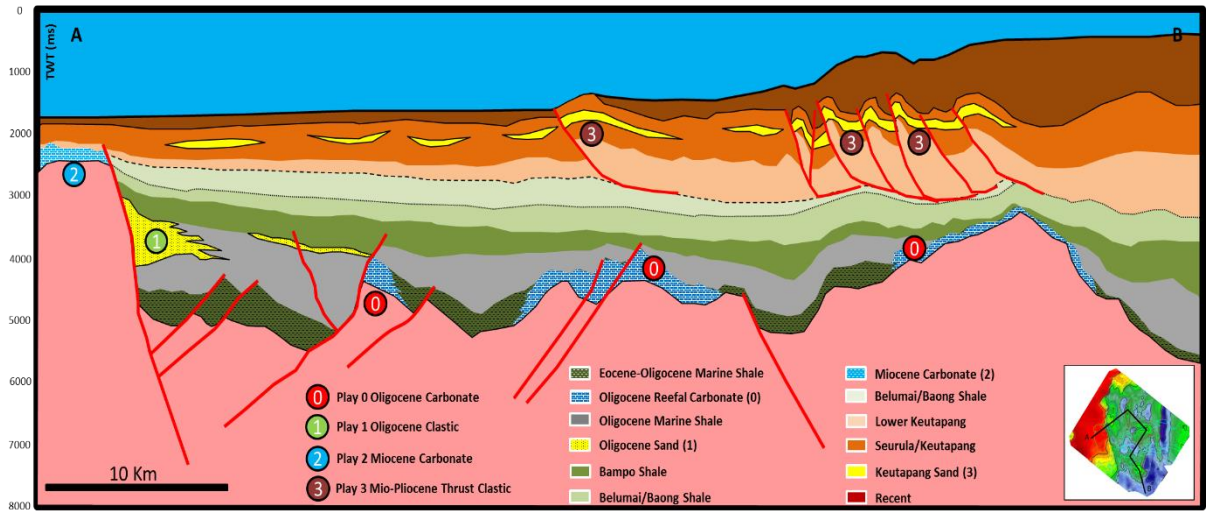

Figure 1. Play Cartoon of Andaman III block. Noted the play 0, Late Eocene-Oligocene carbonate on basement high and changing facies basinward into marine shale.

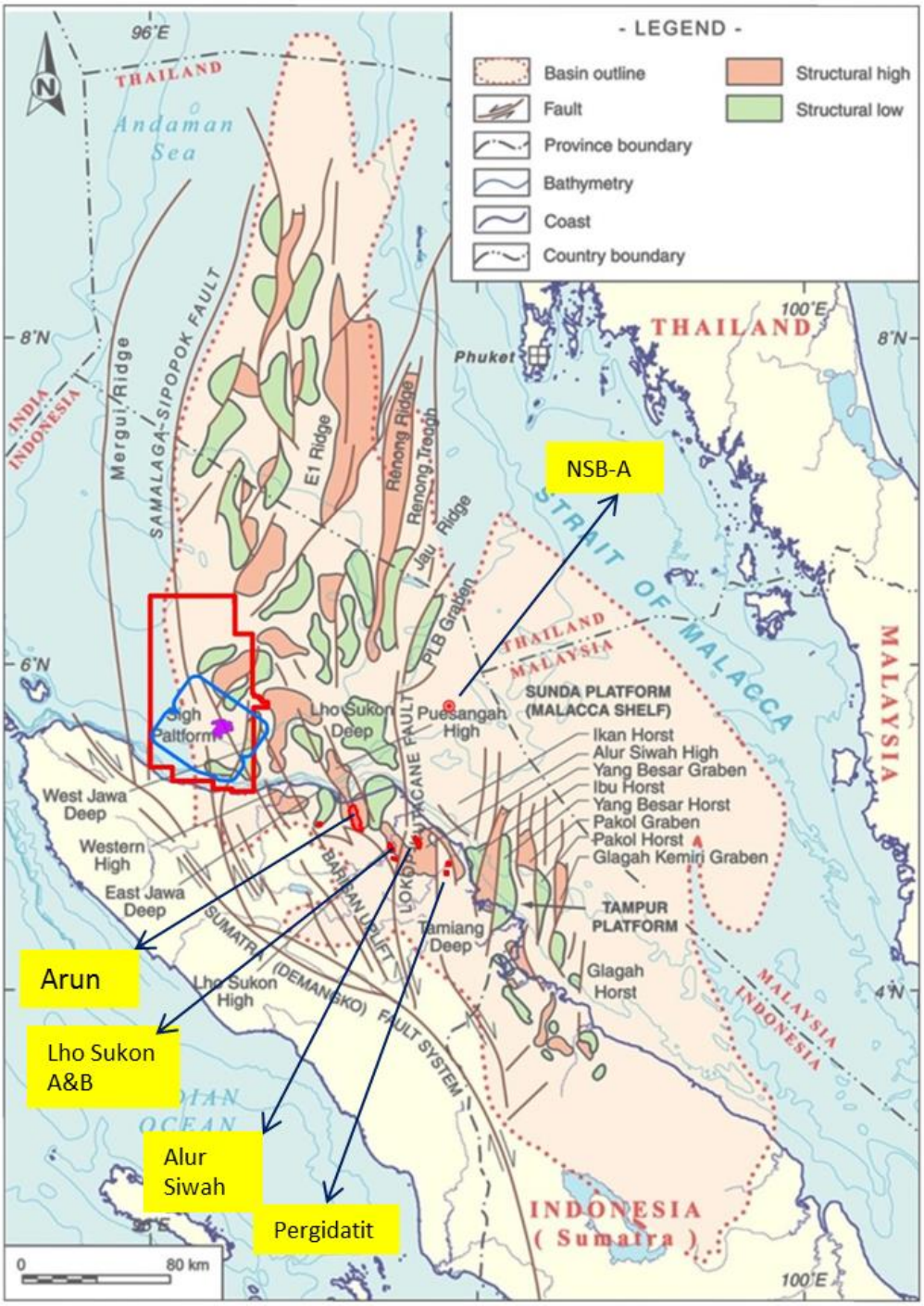

Figure 2. The tectonic map of North Sumatra Basins, shows the main structure controlling the development of highs and lows in this region. The main field at Arun developed on the basement high surrounded by the low proven to contain good source rock. The other highs also have carbonate build-ups with HC marked with yellow colour. Noted that the existing publications do not have a basement high in Andaman III area. The blue box is the new 3D seismic data covering the main prospect.

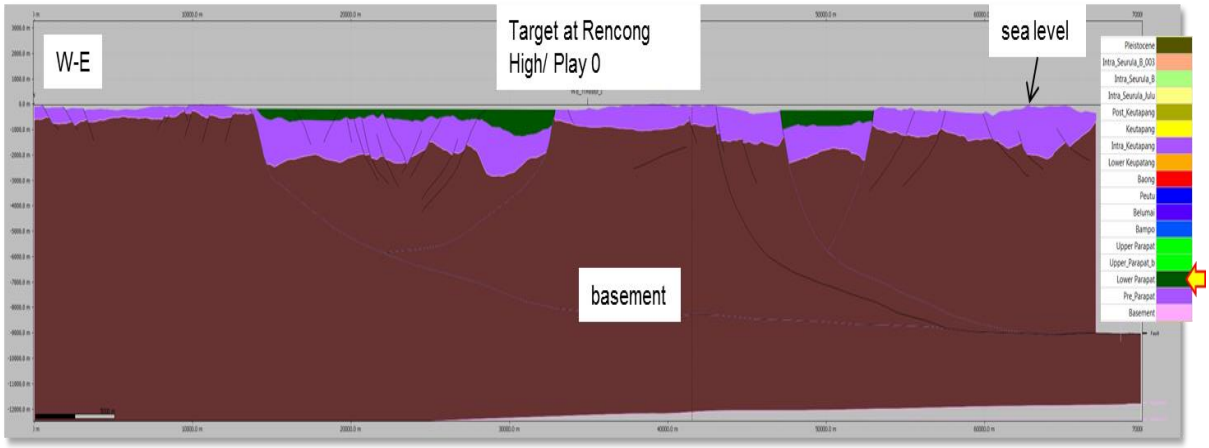

Figure 3. Basin restoration showing that Rencong high was a structural high at the time carbonate was developed.

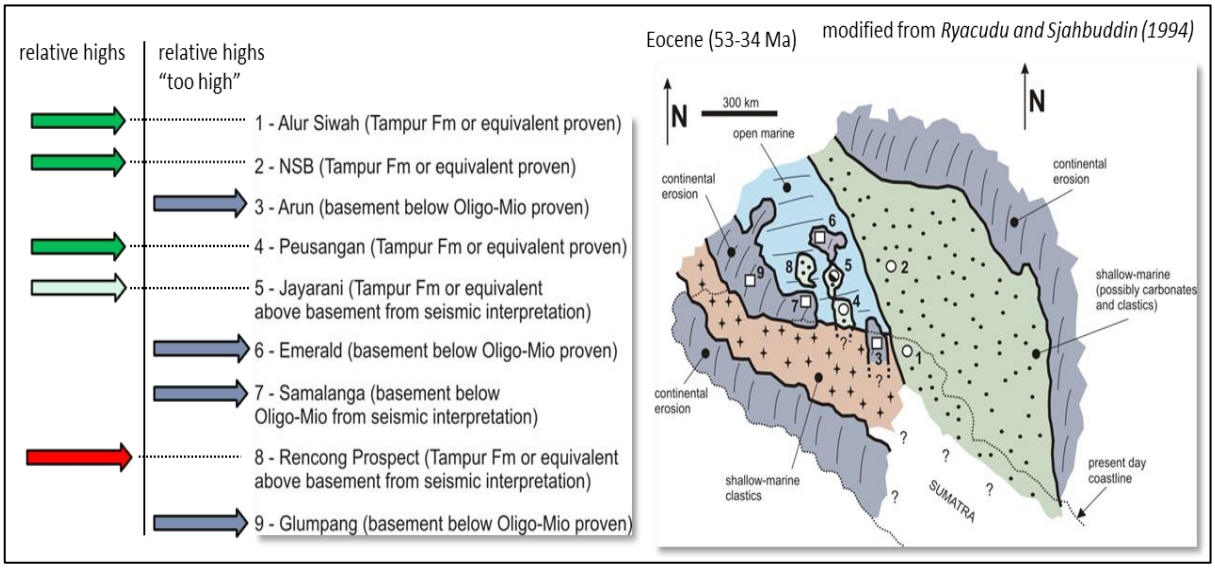

Figure 4. Cartoon showing the development of highs and lows in the North Sumatra basin during Late Eocene. This is showing that most of the basement highs have carbonate build-ups developed.

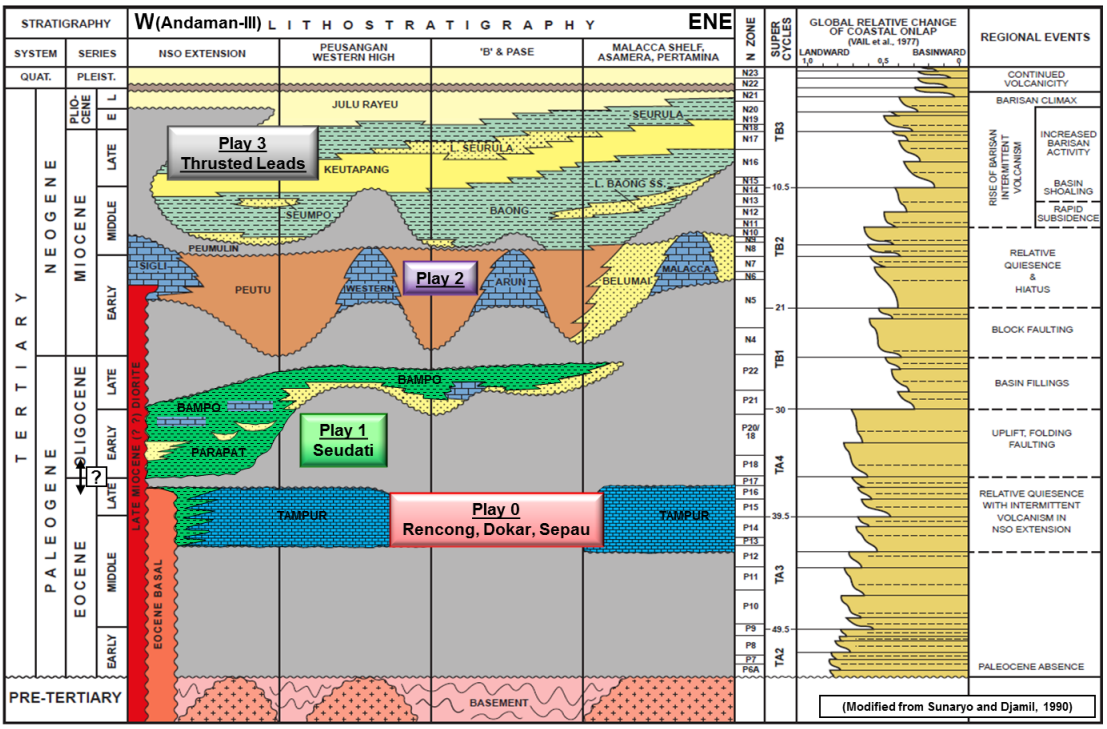

Figure 5. The modified stratigraphy for Western North Sumatra Basin. The main target for the Andaman area is Eocene Oligocene carbonate.

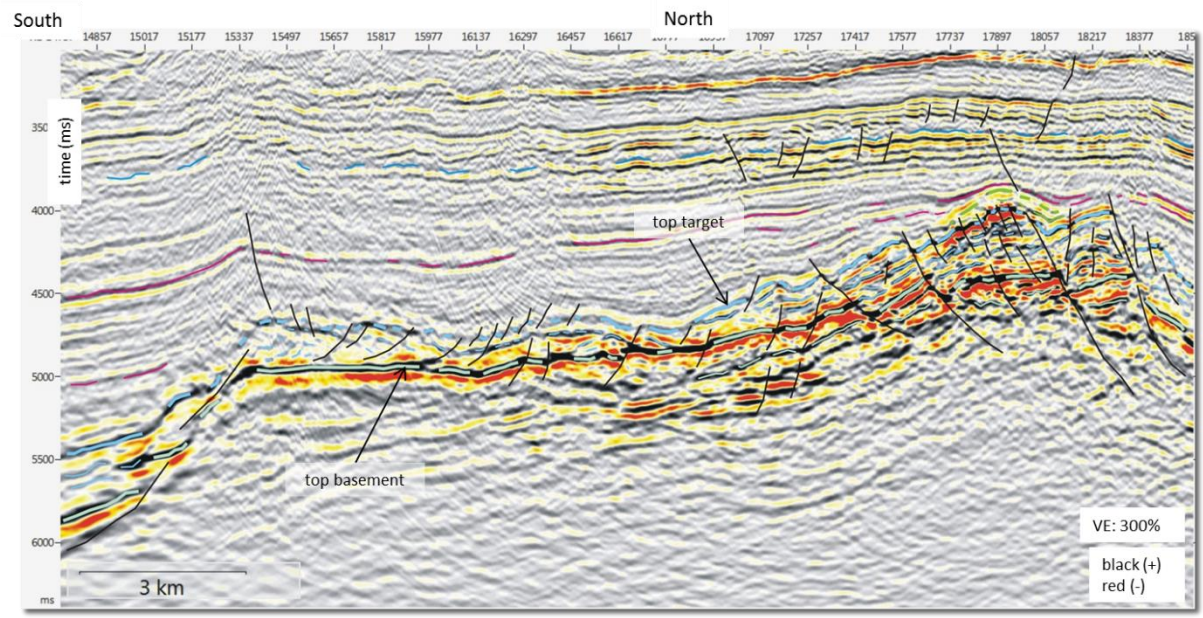

Figure 6. The carbonate seismic facies for the interpreted carbonate succession in the Andaman III area is marked at the base by a high amplitude and continuous reflector that would separate the main target from an igneous / metamorphic basement.

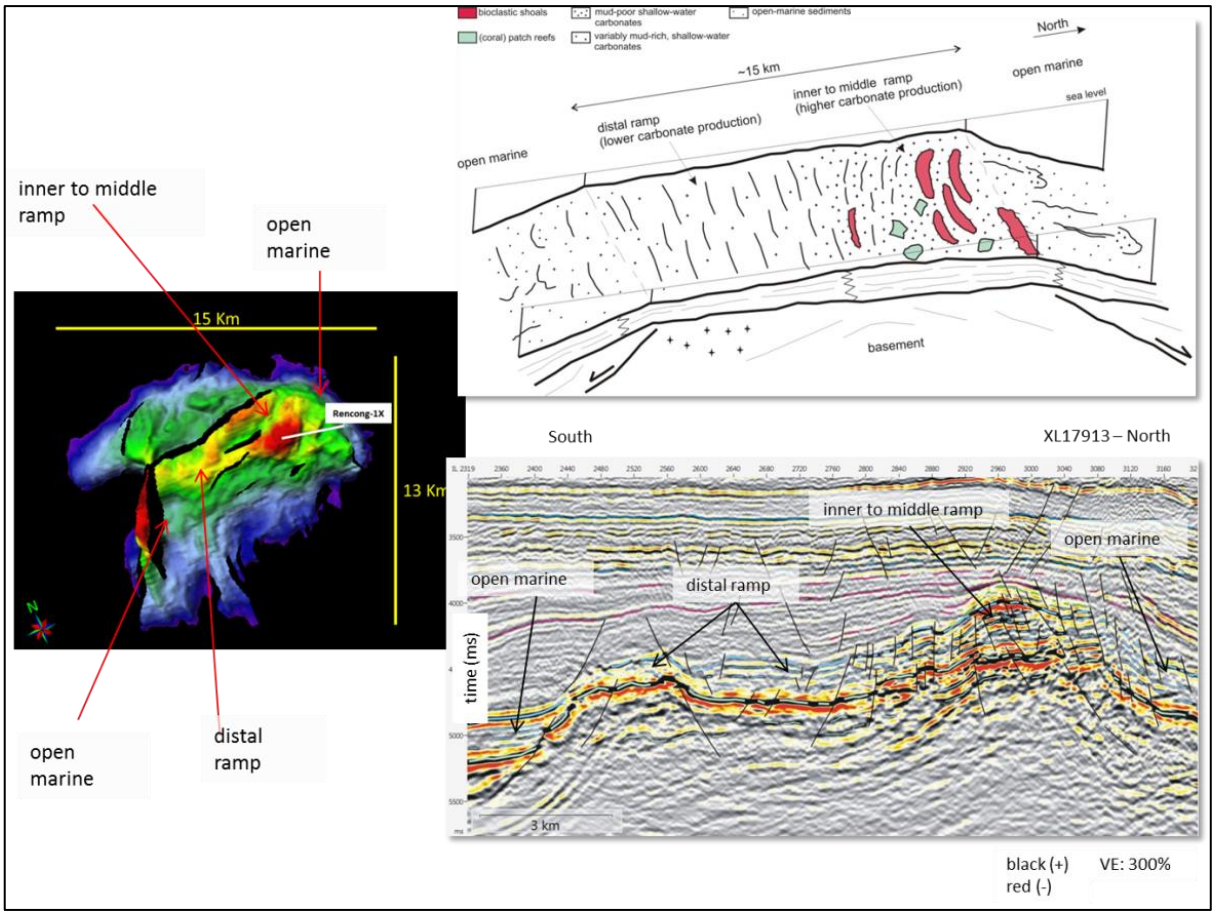

Figure 7. The Seismic pattern within carbonate build-ups shows the thicker section (northward) shows higher reflectivity and mostly parallel-to-basement reflectors, while the thinner area (southward) reveals much lower reflectivity and either parallel-to-basement reflectors or chaotic to transparent seismic responses. Based on the seismic patterns and the geological information, the depositional environment is a shallow-water carbonate ramp deposited on a structural high during the Eocene-Oligocene. The inner ramp facies are probably benthic foram bioclastic packstones interbedded with red algae bioclastic packstones in a high energy shoal setting based on contemporaneous analogs, while the profundal facies are probably marls and shale.

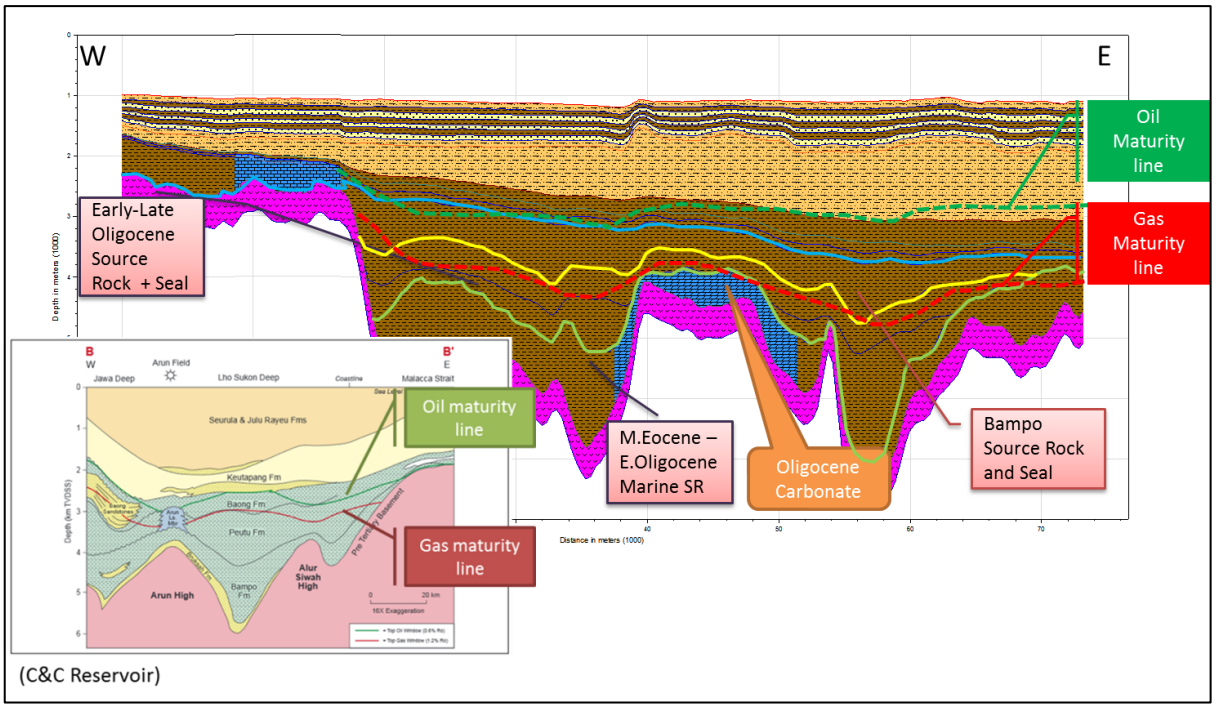

Figure 8. Late Eocene-Oligocene carbonate is surrounded by likely source rock (Arun like as analogue). No long-distance migration required to charge this prospect (Arun like analogue). The Rencong prospect has L. Eocene – E. Oligocene marine sequence, lagoonal facies equivalent to pre-rift (Belumai like as analogue in Arun) as source rock and Late Oligocene sequence plus Bampo as proven source and also seal. The carbonate prospect was exposed during Early Oligocene and in the most part is sealed by Late Oligocene and younger shale sequences.

SPEAKER BIOGRAPHY

Ngakan Alit Ascaria gained an MSc in Petroleum Geoscience at Imperial college, London in 1991 and completed a PhD on Carbonate Diagenesis in Active Fault Zones at University College, London in 1997. He has previously worked as an Exploration Geoscientist at BP Indonesia, Senior Exploration Geoscientist at Pertamina E&P and New Ventures Manager at Premier Oil, covering the Asia Pacific region.

Since 2010 has been Exploration Advisor at Repsol – Talisman Energy, where his current activities include Technical Advisor for exploration activity in onshore and offshore, Coordinator for fracture basement study in South Sumatra and Coordinator for Joint Study Agreements.

He has authored 11 published papers covering various subjects in geosciences and petroleum exploration and two of these "Carbonate play concept in Sopa and surrounding areas: an alternative model for hydrocarbon occurrence, Musi Platform, South Sumatera Basin" and "Integrated study of acoustic impedance modeling and seismic facies to understand reservoir distribution: Kamundan Blok, West Papua" were chosen as a best paper in 1999 and 2001.

In 1991-1997 he was awarded a scholarship from British Petroleum for MSc and PhD program and in a year 2000 he received a Geoscientist Award from Pertamina.

ORAL PRESENTATION

Challenging the Existing Paradigm: A Case for Dual Petroleum System Operation in the Central Palembang Sub-Basin, South Sumatera Basin, Indonesia

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A recent comprehensive evaluation of the Central Palembang sub-basin presents a compelling case for dual petroleum systems, each with different source-reservoir couplets and operating within separate hydraulic regimes at different stages of the basin's evolution. The conventional Oligocene Talang Akar (TAF) source rock charges deep fractured-basement (BSMT), TAF sandstones and Baturaja (BRF) carbonate reservoirs (deep system), whilst often overlooked Upper Gumai (UGUF) source rocks charge younger Middle and Late Miocene Air Benakat (ABF) and Gumai (GUF) sandstone reservoirs (shallow system). Both petroleum systems are isolated from one another by an effective overpressured sealing shale of Lower Gumai (LGUF) age.

Our study area is the Merangin III PSC, located in the Central Palembang sub-basin, and part of the South Sumatra Basin. Our evaluation incorporates seismic interpretation, pore pressure and source rock studies, fluid analysis, basin modelling and post-mortem well reviews. The basin model is calibrated by two adjacent offset pools which act as primary controls: the giant Suban gas field and the Tampi oil field (South East Siera and West Belani fields), lying to the north and north-east of Merangin III respectively.

Five proven hydrocarbon plays are recognised in the area, with deeper BSMT, TAF sandstone, BRF carbonate, being dominantly gas prone, and younger, shallower plays (GUF and ABF sandstone) predominantly oil prone.

Fluid isotope signatures of both deep and shallow reservoirs indicate similar genetic provenance from mixed organic matter (OM) input into a transitional / shallow marine environment. Fluid signatures are correlatable with both TAF shale and UGUF shale source rocks. The main hydrocarbon kitchen identified in the study area is the Belani Deep depocentre (BD Kitchen). Our analysis indicates that the BD Kitchen hosts mature TAF and UGUF source rocks and is therefore responsible for charging both the Suban and Tampi fields, at discrete episodes in the sub-basin's history.

Pore pressure analysis of two flank wells in the area (Bingin Telok-1 and Kemang H-1) reveals that overpressure is preserved in the LGUF interval. It is considered likely that overpressure was developed and retained across the Merangin III PSC area, beyond the BD kitchen, in response to rapid Miocene burial of significant thicknesses of LGUF shale-dominated facies deposited in upper bathyal conditions. Moreover, this overpressure has been locally preserved despite post-Miocene basin inversion. The presence of a confirmed pressure regression below the LGUF shale provides an excellent hydraulic flow barrier between the deep and the shallow systems and suggests that lateral migration dominates within Lower Miocene and older sediments, whereas vertical flux is predominant in the younger post-Gumai section.

Delivered petroleum volumes and phase prediction from basin modelling support the dual petroleum system concept: alternative scenarios relying exclusively on the default Talang Akar paralic source, fail to account for the observed oil and gas distributions. TAF shales mainly provided gas to the fractured BSMT, TAF sandstone and BRF carbonate below the laterally

extensive LGUF shale, prior to significant maturation of the overlying UGUF counterpart. These younger UGUF source rocks, inferred from our regional South Sumatera source rock database and supported by outcrop data from the Sarolangun area, are currently oil mature in the centre of the BD Kitchen; they are interpreted to have recently charged the shallow GUF and ABF plays, with Tampi being currently the best documented example.

SPEAKER BIOGRAPHY

Welly Ramadan graduated from the Maths and Natural Science Faculty at the University of Padjadjaran in Bandung in 2005, and since then has honed his geological skills with a small but diverse range of quality companies, including IOCs and local Indonesian Operators. Besides Mandala, these include Premier, Bukit and Paradigm, and this experience set has provided exposure to new ventures, exploration, development and production geology – in both on- and offshore assets. Welly's recent appointment as Subsurface Technical Advisor in Mandala's Jakarta office reflects his proficiency and capabilities across a broad spectrum of technical inputs, and as an independent thinker. He has particular interests in the petroleum systems of Indonesia and will address some aspects of the South Sumatra system today

ORAL PRESENTATION

Uncover the Overlooked Gumai Play Potential at Jabung Betara Complex, Indonesia: A Best Case Study of Gas While Drilling Classification in Finding the New Pays

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The Gumai Formation is the most prolific reservoir and the primary exploration target in the South Sumatra Basin. Marine conditions were established during the continuation of transgression sequence and led to open marine facies deposition in Early Miocene. Sandstone thickness and quality increased significantly in the Gumai section as marine conditions regressed regionally in the basin.

The development phase of Betara Complex area had only assumed hydrocarbon reservoirs at Lower Talang Akar Formation (LTAF) since 2001 before Gumai potential was ever proven. As part of a continuous exploration effort, PetroChina drilled the NEB Base-1 exploration well in 2013 penetrating over 3000ft MD (2000ft TVD) through basement target. Unexpectedly, a Drill Stem Test (DST) showed 4.45 MMSCFD of gas & condensate flow from Gumai Formation with 0% CO_2 content, opening an opportunity to develop new potential in the Betara Complex area. Following the success of NEB Base-1 testing, a study of Gas While Drilling (GWD) behaviour was conducted in all the existing wells to obtain new potential zones and improve integrated reservoir interpretation in the Gumai Formation. Data integration of mudlog and geophysical interpretation is required to tackle limitations of conventional wireline logs in the Gumai interval. Over the course of the study potential zones became apparent when GWD of more than 200 units was applied on Southwest to Northeast well-to-well correlation. The zones are correlatable with reservoir characterization encompassing petrophysical analysis and seismic attributes of the Lower, Intra and Upper Gumai Formation. Furthermore, blind well tests performed by applying correlation and integration amongst mudlogs, DST, and pulsed neutron reservoir monitoring measurement (cased-hole log) data has proven the reliability of the method and satisfies Gumai laminated shaly sand reservoir distribution in the Betara Complex.

All in all, the GWD classification method provides justification of reservoir potential and success ratio in order to uncover and de-risk the overlooked play potential.

Keywords: Gumai, Gas While Drilling, South Sumatra Basin

Speaker Biography

I Gusti Agung Aditya Surya Wibawa (Adit) has worked as Operations Geologist in Exploration Department, PetroChina International Jabung Limited Indonesia, since 2016. Adit received his bachelor degree from the Department of Geological Engineering, University of Diponegoro in 2015. His professional experience includes well logging, petrophysical analysis, and supervision of wellsiting for Jabung exploration and development wells.

ORAL PRESENTATION

Sumatra Deep Basin Gas and Meeting Indonesia's Growing Gas Demand

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Indonesia's energy demand has been increasing at 9% per annum and is projected to continue doing so for the next decade at least. Although gas is widely recognized as the preferred and cleaner energy source to fuel this growth, domestic production has been declining at 3% per annum, since the peak of 2 Tcf in 2010, and the GOI has been forced to throttle back domestic gas consumption in favour of readily available cheap coal in an attempt to balance national treasury benefits from LNG exports with domestic energy requirements. This trend will continue unless a material and readily available domestic gas source is developed. Such a resource likely exists within the deep basins of Sumatra.

In 2012, an IHS report estimated over 200 Tcf of unconventional deep gas resource in Sumatra. That potential is realistic, if not conservative. The 27 Bboe of conventional reserves discovered in Sumatra represent no more than 10% of total hydrocarbons generated; meaning no less than 300 Bboe have been generated within the Sumatran basins, with an estimated 70% of these hydrocarbons still in-situ. Whereas the technology to produce these tight reservoirs has existed for three decades (ground zero being the Jonah Field in Wyoming), the GOI has only recently incentivised industry investment in the unconventional business with much improved contract terms.

The material investment of money and skill that this play requires resides with the large international oil companies (IOCs), but the recent industry downturn, subsequent retrenching of oil and gas investment, and withdrawal of IOCs to the relative safety of continental United States has conspired to delay the development of the deep gas play in Indonesia. Still, the resource remains to be exploited, and increasing Indonesia gas demand, substantial improvement in domestic gas pricing, proven production technology and improved contract terms makes this play exceptionally commercially viable. With the recent resurgence in oil price, the IOCs are starting to cast around for the next play that will move their corporate needle. The Sumatran basins have been company-makers in the past and are poised to do so again.

SPEAKER BIOGRAPHY

Mr Sykora is a professional geologist and an oil and gas entrepreneur with 35 years of experience in onshore and offshore petroleum exploration and business development in North and South America, Russia, Australia, Africa, Arabia and South East Asia. He has previously held exploration, business development, senior country and regional management positions with Gulf Canada, Nexen and Talisman and has been an integral part of oil and gas discoveries and developments in Northern and Western Canada, Yemen, Nigeria, Vietnam, PNG, and Indonesia. As founder and CEO of Bukit Energy Inc. he organically grew Bukit Energy into the third largest land holder in Sumatra within three years of inception. Mr Sykora holds a MSc in Geology from Carleton University. He is a member of the Canadian Society of Petroleum Geologists and the Association of Professional Engineers and Geoscientists of Alberta and the South East Asian Petroleum Exploration Society.