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DEEPWATER DISCOVERIES IN TURBIDITE SANDS OF THE MAKASSAR STRAITS, EAST KALIMANTAN INDONESIA

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ABSTRACT

Advances in exploration and drilling technology led to discoveries in progressively deeper water on the Western Makassar Strait slope. Step one was recognition of Mio-Pliocene aged channel-shaped features outboard of the shelf-slope break, in water too deep for existing drilling rigs in the region. Step two was advancement of technology that allowed drilling of deep-water prospects, leading to discovery of oil and gas in slope-channel sands at Merah Besar and Seno. Additional upgrades extended drilling to over 3000 feet water depth, resulting in discoveries farther to the east (Gendalo, Ranggas). Further refinement led to drilling of the Gehem prospect in over 6000 feet of water to total depth over 15,000 feet, thus reaching Middle Miocene fan-sands containing a significant gas column. Substantial exploration potential remains in base-of-slope fan plays of the Middle Miocene. Engineering advances have extended drilling capabilities to water depths of over 7,500 feet. The exploration and drilling team has turned exploration plays into discoveries, and if this history is a guide, then future innovation will turn the Indonesia Deepwater Development project into reality.

INTRODUCTION

The onshore area of the Kutei basin has been a hydrocarbon province since 1897. Over the years, exploration progressed from west to the east (Figure 1); from the Sanga Sanga onshore trend, toward progressively more difficult operating conditions in the swamps of the Mahakam Delta and onto the shallow marine shelf, leading to the discovery of the offshore Attaka Field in 1970. Shelf exploration used jack-up rigs, but the 300-foot depth contour at the shelf-edge marked the limit of jack-up drilling.

Mobil Oil started deepwater exploration in Indonesia when they signed the Makassar Straits Production Sharing Contract in 1973; the western edge of the block was approximately at the 600 foot depth contour and the eastern edge was marked approximately by the 5000 foot contour. Mobil acquired various 2-D seismic surveys, and in 1994, they brought in the West Delta semisubmersible rig to drill their first deepwater well, Perentis-1, in 1245 feet water depth, which did discover oil and gas. Though Perentis-1 was sub-commercial, it proved the existence of a petroleum system outboard of the East Kalimantan shelf edge (Peters et al., 2000). To the north, regional studies on Unocal's East Kalimantan Production Sharing Contract (Lumadyo, 1999) indicated that during Miocene and Pliocene low-stands of sea-level, it was likely that deltaic sands would extend to the shelf edge and continue across the shelf-edge onto the slope (Figure 2). Unocal acquired their first deep-water 3D seismic survey in 1995 on the upper slope of the East Kalimantan PSC (Figure 3). The data showed Pleistocene bright-amplitude events (Figure 4) within channel-shaped features that looked like sand, and deeper amplitudes in the Pliocene section were interpreted as gas-bearing slope-channel sands (Brown et al., 1999), but water depths at potential locations exceeded 2000 feet, making them accessible only with a semisubmersible rig.

METHODS

A deepwater exploration program on the East Kalimantan PSC was going to be expensive, since the day-rate for a semisubmersible was much higher than for a jack-up. Prospects were identified, but could they be drilled? Unocal had been drilling jack-up wells on the shelf for years, and by the mid 1990's an attempt was made to balance drilling costs against geological and geophysical evaluation needs. Explorationists were asked to limit logging of unsuccessful wells in exchange for the chance to drill three wells for the price of two, and the "Saturation Exploration" or "SX" philosophy was born. The next step was to assemble a portfolio of prospects in such a way that failure of any one prospect would not condemn all the rest of the prospects on the list. This meant that a semisubmersible rig could be contracted on a long-term basis to drill a series of wells, one

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after the other. The set-list of locations allowed deployment of a pre-laid anchor system for mooring the rig at each location. Once the first well was completed, the rig disconnected from anchors and moved to the second location where a second set of anchors had already been placed, and immediately began to attach itself to the pre-laid mooring system. Another significant cost savings came from reliance on “MWD” (Measurement While Drilling) logs for a primary source of data for exploration wells. Generally, wireline logs are higher quality than MWD data, but in many cases, MWD logs are adequate to determine presence or absence of hydrocarbons. If it is clear that hydrocarbons are present, then a more thorough follow-up evaluation can be made with wireline logs. Increases in efficiency drove Unocal’s deepwater agenda in Indonesia. Explorationists found the prospects, but the drillers made the program possible.

RESULTS

The Merah Besar discovery

In 1996, Unocal assembled a portfolio of deep-water prospects and brought in the Sedco 602 semisubmersible to drill a series of wells using pre-laid mooring systems, in water depths ranging from about 1,400 to 1,800 feet. The Merah Besar prospect (Figure 3) was a faulted-anticline of approximately 40 square kilometers area that formed as a result of rollover along a listric-normal fault (Lumadyo, 1999). Merah Besar 1 well was spudded in November 1996 in 1,432 feet water, targeting a succession of bright-amplitude events in a channel-shaped feature. LWD logs and mud-log gas readings indicated gas within Pliocene and Upper Miocene channel sands on the upper slope of the Makassar Strait (Teague et al., 1999). This well also introduced the use of wireline formation-testing with the Schlumberger MDT (Modular Dynamic Formation Tester) tool (Brown et al., 1999). MDT pressure measurements and fluid pumps-outs confirmed 108 feet of net gas pay in the Merah Besar 1 discovery (Unocal press release, 1997).

Following Merah Besar-1, plans were made to take cores and perform DSTs in subsequent Merah Besar evaluation wells. This was just another extension of the SX philosophy: if hydrocarbons are indicated, then run wireline logs and MDT; if a discovery is made, appraise it with wells that will cut cores and perform drill-stem tests. Cores from Merah Besar 2 and 3 recovered sands with excellent porosity and permeability, and finally a series of DSTs at Merah Besar 5 flowed at a rate of 9,430 barrels oil per day and 7.4 MMcf gas per day from a zone at 11,120 feet (Unocal press release, March 1998). The Merah Besar structure extended across the boundary from the East Kalimantan PSC over to Mobil’s Makassar Straits PSC (Figure 3), and in a deal that earned Unocal a 50% interest in the Makassar Straits PSC, Unocal drilled the Merah Besar 6 well with Mobil on the Makassar Straits PSC; the well flowed at a rate of 24.8 million cubic feet of gas and 860 barrels of oil per day. Two other zones tested at 582 barrels oil per day in one zone, and 710 bo/d in a second zone (Unocal press-release, September 1997). These tests confirmed the excellent reservoir quality observed in cores, and the fluid types indicated by MDT pressure gradients.

A larger structure was identified on the Makassar Straits PSC to the northeast of Merah Besar, but the water depths exceeded 2,700 feet, beyond the capability of the Sedco 602 rig. This was the Seno Structure (Figure 3), which had a thicker section of amplitudes than Merah Besar. It was an attractive target, but was un-drillable with existing technology. It was time for the drillers to meet the challenge.

The West Seno Discovery

The Merah Besar wells were close to the edge of the 602 rig’s water-depth capability, but Seno was too deep. Unocal worked with the rig contractor, Transocean, on a series of adaptations to the mooring and riser systems that extended the rig’s water-depth capability up to 4,000 feet, deeper than any existing exploration prospects. Now it was up to the geologists and geophysicists to catch-up to the drilling team.

The first well drilled at Seno was West Seno-2, and not West Seno-1. Of course the first well intended to be drilled was West Seno-1, but for operational reasons, the target was shifted to West Seno-2. This highlights the important working relationship that Unocal had with BPMigas (now named SKK Migas), who had encouraged the efficiencies that Unocal was building into its exploration program. BPMigas did not hesitate to approve the last-minute well change with the result that no time was lost in re-doing paperwork. West Seno-2 was spudded on July 25, and completed on August 25, and the rig immediately spudded West Seno-1 on August 26, 1998. Both wells were completed within their scheduled time, only the order of drilling was changed. Alnes (2004) documented the important role of BPMigas in the Unocal deepwater exploration program.

West Seno-2 confirmed oil and gas in bright amplitudes in the Seno structure (Figure 5), encountering over 190 feet of oil sand (Redhead et al., 2000). A drill-stem test flowed at a rate of 10,069 barrels of 39-degree API gravity oil and 9.5 million cubic feet of gas (Unocal Press Release, August 1998). In contrast to Merah Besar, where the canyons were relatively narrow on the upper slope, Seno was at a mid-slope position and the channels appeared to be wider with greater lateral continuity of seismic reflectors. The discovery was immediately delineated by West Seno-1 which encountered over 370 feet of oil and gas sands in an adjacent downthrown fault block. Success at West Seno-2 and -1 justified an extensive evaluation program that included cores and additional DST's in appraisal wells. A total of 5 cores were cut over a combined interval of 765 feet in the West Seno-4 well, and recovered sands with porosities ranging from 22 to 32% and permeabilities ranging from 150 to 1500 mD (see Redhead et al., 2000 for details of tests and reservoir quality). Three separate drill-stem tests confirmed reservoir quality and deliverability of the sands. DST-1 flowed 8250 barrels oil per day and 8.76 million cubic feet of gas, DST-2 flowed 2373 bopd and 2.52 MMcf/d gas, and DST-3 flowed 8721 bopd and 7.3 MMcf/d gas.

A separate structure was identified about 15 km north of Seno, named the Bangka prospect. Bangka-1 was drilled in 3156 feet of water just after the Seno wells. The Bangka-1 discovery proved that the petroleum system of deepwater sands charged with oil and gas was widely distributed across the region.

West Seno - The First Deepwater Development in Indonesia

The West Seno Plan of Development was approved in September 1999, only 14 months after drilling the discovery well. A three-dimensional static geologic model was built based on well and seismic data, and formed the basis for volume and reserves assessment, well planning and design, and economics for the project (Inaray et al., 2004). Engineering innovation was crucial to the economics of the project. There were no other deepwater developments in Indonesia to serve as models. The final design for the development was a Tension Leg Platform (TLP), where the legs of the platform are actually production risers for the development wells. This was simply a continuation of the progression of technology from the first onshore development in 1897, to the swamps of the Mahakam delta, to the shallow shelf at Attaka, and finally to deep water at West Seno.

The West Seno TLP was set in 3,349 feet water depth and is linked to a nearby floating production unit where the produced oil and gas is processed and shipped through separate pipelines to the onshore Santan terminal on East Kalimantan. By December 2004, 28 development wells had been put on production. Ten of the development wells were horizontal wells that had approximately 1000 feet of reservoir sand open to production through wire-wrap screen completions. Eighteen of the development wells were high-angle deviated wells positioned to penetrate thick sequences of stacked channel sands (Heri et al., 2009). The original West Seno plan of development concept envisioned development drilling from a second TLP to be set later in the 2000's. However, engineers were able to devise an extended-reach drilling (ERD) plan that allowed exploitation of reservoir sands outside the reach of previous technology. The ERD project was launched in March 2012, and succeeded in providing sustained high production rate without the need to spend money on a second TLP (Hoang and Somantri, 2013).

Exploration East of Seno

The sands at Merah Besar and Seno are channel-sands that were deposited in slope-canyons. Each slope canyon is a topographic feature that may contain multiple anastomosing channel sands in the bottom of each canyon that ultimately feed into distributary-channels of base-of-slope fans. Figure 2 shows the recent sea bottom profile; slope canyons tend to be narrow on the upper slope and become broader on the lower slope, and ultimately feed sediment onto base-of-slope fans. The same processes were expected for the Miocene, and it was reasonable to expect base-of-slope fans lay east of Merah Besar and Seno. Figure 3 also shows that any wells drilled to explore for Miocene fans would be located at water depths considerably greater than the 3000-foot water depth at Seno. The Miocene fans probably extended east of the 5000 foot water-depth contour, and this would put them beyond the eastern boundary of the Makassar Straits PSC, into open acreage. Unocal approached Migas with a proposal to establish two new Production Sharing Contract Areas to the east of the Makassar Straits PSC. The Rapak PSC was signed on December 4, 1997, and the Ganal PSC was signed on February 24, 1998 (Figure 1). At the time of the signing of these PSC's in early 1998, the deepest well drilled so far 3,101 feet, so if these blocks were going to be explored, it would be necessary to make significant upgrades in drilling capability.

Unocal contracted the Sedco 601 rig in 1998 and made modifications to extend its drilling capability to over 6000 feet in order to drill prospects on Rapak and Ganal. The first effort on the Ganal PSC was acquisition of a regional 2 by 2 km grid of seismic data totaling 4,850 line kilometers, in early 1998. In accord with the SX philosophy, it was decided not to acquire a 3D survey until a functioning hydrocarbon system could be proven on the block (McKee and Dunham, 2004). The 2 x 2 km grid was adequate to identify several large anticlines, and define key surfaces of sequence-stratigraphic significance. Strike lines parallel to slope contours showed a series of several large slope canyons of Pliocene and Upper Miocene exceeding 2 km in width. Amplitude maps compiled from the 2D strike and dip lines (Figure 6) showed elongate bodies of bright negative amplitude extending from the southern Mahakam Delta, across the shelf through the Peciko field, and over the shelf edge onto the Ganal PSC. Mapping of Plio-Miocene horizons identified slope canyons that appeared to broaden in width down the slope. However, the farther down the Plio-Miocene slope from west to east, the deeper the water depth becomes.

The first target for the Ganal PSC was the Gep prospect, which was a Pliocene slope canyon that was cut by a normal fault that had undergone minor inversion, thus providing the up-dip trap for the interpreted channel sands (Figure 7). The Gep-1 well penetrated a nearly 400 foot thick sequence of shale with very thin gas sands before finally penetrating a nearly 100 foot thick massive sand with excellent reservoir quality, but with gas present only in the uppermost 11 feet of the sand, with the rest being water saturated. Several MDT pressure measurements in the sands showed the presence of a single gas column 400 feet thick within the thin beds and the massive sand (Figure 7). The maximum gas column that can accumulate under a seal is reached when the buoyancy pressure of the gas reaches the displacement pressure of the water within the micro-pore system of the seal. When gas pressure exceeds displacement pressure, the gas will leak through the seal. It is likely that the Gep-1 gas column was balanced to the sealing capacity of the shale top seal, with the result that only 400 feet of column could be trapped beneath the seal; any more gas than 400 feet would leak out through the seal. Unfortunately, very little of the gas was trapped in the massive sand.

Gep proved the presence of sand and gas on the Ganal PSC, but it also showed that the relatively shallow depth below mudline of the Pliocene sequence increased the risk of seal failure; shallow burial means less compaction of shales and lower sealing capacity relative to more deeply buried shales. Miocene prospects had been mapped, but the 601 rig was still working its way up to being able to drill in the deeper water where these prospects were located.

Other packages of bright-amplitude seismic reflectors had been identified on the 2 x 2 km 2D grid, and these reflectors did not appear to be confined to erosional channels. The geometries at the edges of the amplitude package were down-laps, and down-laps would be more characteristic of a submarine fan, rather than a channel sand. Modifications to the Sedco 601 anchoring system had progressively increased the water-depth limits for the rig, to the point where these fan prospects were drillable. Following the SX philosophy, these prospects were set to drill one after another. Failure of any one of them would not change the drilling order; each of them was an independent test of the submarine-fan play concept.

The Goda-1 well spudded in December 1999 in 5672 feet of water; this was the deepest water well drilled to date in the Makassar Straits. The interpreted fan was not in a structural closure and so this was a pure stratigraphic trap play. Goda-1 found over 375 feet of sand, but all of it was wet; the strat-trap had failed. McKee and Dunham (2004) reviewed the balance of cost versus risk when relying on 2D data for picking exploration well locations.

The Gendalo Discovery

The Gendalo prospect had good indications of downlapping fan geometries, but details were obscured by a severe water-bottom multiple, but in contrast to Goda, there appeared to be a structural trap at Gendalo. Gendalo-1 spudded in January 2000, and found gas sands in the target horizon (Figure 8). A Gendalo-2 appraisal well was quickly inserted into the drilling order; it was located 3.7 kilometers north of Gendalo-1 and confirmed that gas sands extended across the width of the interpreted fan (Dunham and McKee, 2001), and most significantly, MDT pressures taken in Gendalo-1 and Gendalo-2 plotted on the same gas gradient (Figure 8). This supported the interpretation that sheet sands were present in a laterally continuous submarine fan within the Gendalo structure. Subsequent to the Gendalo discovery, the Sedco 601 rig proceeded into even deeper water, drilling the Gula discovery in 6050 feet of water and the Gada discovery in 6230 feet water depth (Figure 1). Following confirmation of the Ganal hydrocarbon system, the Sedco 601 rig returned to the Rapak PSC to drill the large Ranggas Anticline.

The Ranggas Discovery

Ranggas is a large anticline located southeast of Seno, in over 5,300 feet of water depth (Figure 9). The Ranggas structure contained bright-amplitude packages that looked like the oil and gas sands at Seno, meaning that the amplitude packages looked more like channel sands rather than sheet sands (Figure 10). The first 3 wells drilled at Ranggas confirmed that both oil and gas were present in the sands. The Ranggas 4 appraisal DST flowed 8,158 barrels of oil per day and 6.4 MMcf/d gas from a single interval between 10,174 and 10,224 feet (Unocal Press Release, 2002). Subsequently, three more appraisal wells confirmed that all amplitude targets were oil and gas, and that literally thousands of feet of oil and gas sands were present in the Ranggas Structure. However, MDT pressure measurements made in these wells (Widya and Sena, 2009) confirmed that individual hydrocarbon sands were isolated in separate compartments by pressure-sealing shales (Figures 9). Consequently, it will take a complex plan to develop Ranggas Field. To date, no laterally continuous sheet sands like those present at Gendalo, have been found in the Ranggas structure. In the 1980's, Unocal faced a similar problem with channel sands in their Gulf of Thailand gas project. The original plan of development envisioned production from laterally continuous sands from relatively few wells. It became evident quickly that these were channel sands. It was drilling technology that saved the project. The drillers used directional and high-angle wells to intersect numerous separate channel sands with single wells, thus allowing successful development of these gas fields. Geophysicists using 3D seismic data were able to image the channel sands, and the drillers were able to hit the targets. At the time, this approach was revolutionary, but it is now standard practice in many areas. The difference between the Gulf of Thailand and Ranggas is water depth; but the drillers have shown time after time that they can overcome technical challenges. As of the present time, the Ranggas field has not been developed, but if history is a guide, then future advances could recover this proven resource. Ranggas development will involve geophysical imaging of individual sand bodies, sedimentologic interpretation and stratigraphic mapping of sand bodies, and engineering design of directional or horizontal or multi-lateral wells that will intersect as many sand bodies as possible from as few wells as possible. It may not be possible now, but it will certainly be attainable in the future.

The Gehem Discovery

A large anticline had been mapped east of Ranggas, but most of it was in water depths over 6000 feet, and the target was a bright amplitude event stratigraphically deeper than the Upper Miocene channel sands at Ranggas (Figure 10). The extent of the amplitude and the sequence-stratigraphic model for the region suggested that this target was a base-of-slope fan that might contain laterally continuous sands more like Gendalo than Ranggas. The Gehem-1 well spudded in May 2003 in 5981 feet of water, and reached the amplitude target at a depth just below 15,000 feet TVDSS (Figure 10). The target was confirmed to be a thick package of gas sand over 200 feet thick. MDT pressures confirmed a continuous gas column within the sand package, and shortly thereafter the discovery was appraised by Gehem-2, located 2.75 km to the southeast. Gehem-2 encountered the target horizon as prognosed, and MDT pressures matched the same gas column seen at Gehem-1, supporting the sheet-sand interpretation indicated by the continuous seismic amplitude character between the wells (Unocal press release, 2003). A drill-stem test of the Middle Miocene target flowed 27.6 MMcf/day and 1700 barrels condensate/day, confirming the excellent reservoir quality of the sand (Unocal press release, 2004). Gehem-3 drilled in 2004 and located 2.8 km northwest of Gehem-1 and 5.5 km northwest of Gehem-2 delineated the northern extent of the reservoir and confirmed a gas-water contact at the mapped structural spill-point of the reservoir. In summary, the Gehem structure contains an extensive gas sand with excellent reservoir properties.

Deepwater Field Development

The main components of the proposed Indonesia Deepwater Development Project are the Gendalo and Gehem Hubs (Chevron, 2015), each of which with a Floating Production Unit, subsea drill centers, and natural-gas and condensate pipelines. The project has a planned design capacity of about 1 billion cubic feet and 47,000 barrels condensate per day; however the final investment decision has yet to be made.

Chevron demonstrated its commitment to Indonesia Deepwater Development when on August 31, 2016, Chevron Indonesia Company announced that it had achieved natural gas production from the Bangka Field Development Project, where production is achieved through a subsea tieback to the West Seno FPU.

The theme of this presentation from the beginning is that exploration success drives engineering technology to overcome progressively more difficult obstacles. From onshore to swamps to marine shelf to deepwater, engineering has turned discoveries into commercial developments. Chevron and SSK Migas are actively working to try and figure out the most efficient and economical plan of development for these discoveries. If history is a guide, then it is reasonable to expect that the engineers will succeed, and IDD will move forward.

THE KUTEI DEEPWATER PETROLEUM SYSTEM

Source rocks are sands that contain terrestrial organic matter that was transported into the basin by the same turbidity currents that brought in the sand (Saller et al., 2006). The reason that some structures contain oil and others contain gas is explained by the process of migration-fraction, whereby an original condensate-rich gas is generated by the Type III kerogen in the sands and later becomes separated into liquid and gas phases (Figure 11) as the wet-gas migrates along faults into shallower reservoirs. (Lin et al, 2005). The timing of generation and migration extends from Pliocene to Recent time, with the result that relatively young reservoirs and traps are charged by hydrocarbon. Reservoirs are Pliocene through Middle Miocene sands deposited in slope channels and base of slope fans, depending on where the sands were deposited on the Makassar Slope. Traps are structural, involving both fault traps and rollover anticlines; stratigraphic traps have not worked so far. The seals are formed by hemipelagic shales that are sufficiently impermeable to trap thick hydrocarbon columns and drive the formation of strong overpressure in the section.

CONCLUSIONS

Since 1897, discoveries and developments have progressed from west to east, from onshore to deep water, along the western margin of the Makassar Straits (Figure 12). Geotechnical exploration teams defined prospects; drilling engineers and rig superintendents turned the prospects into discoveries and developments. Geologists, geophysicists, reservoir engineers and drilling engineers combined into a single team that achieved results. We all worked together. It was a great place to work.

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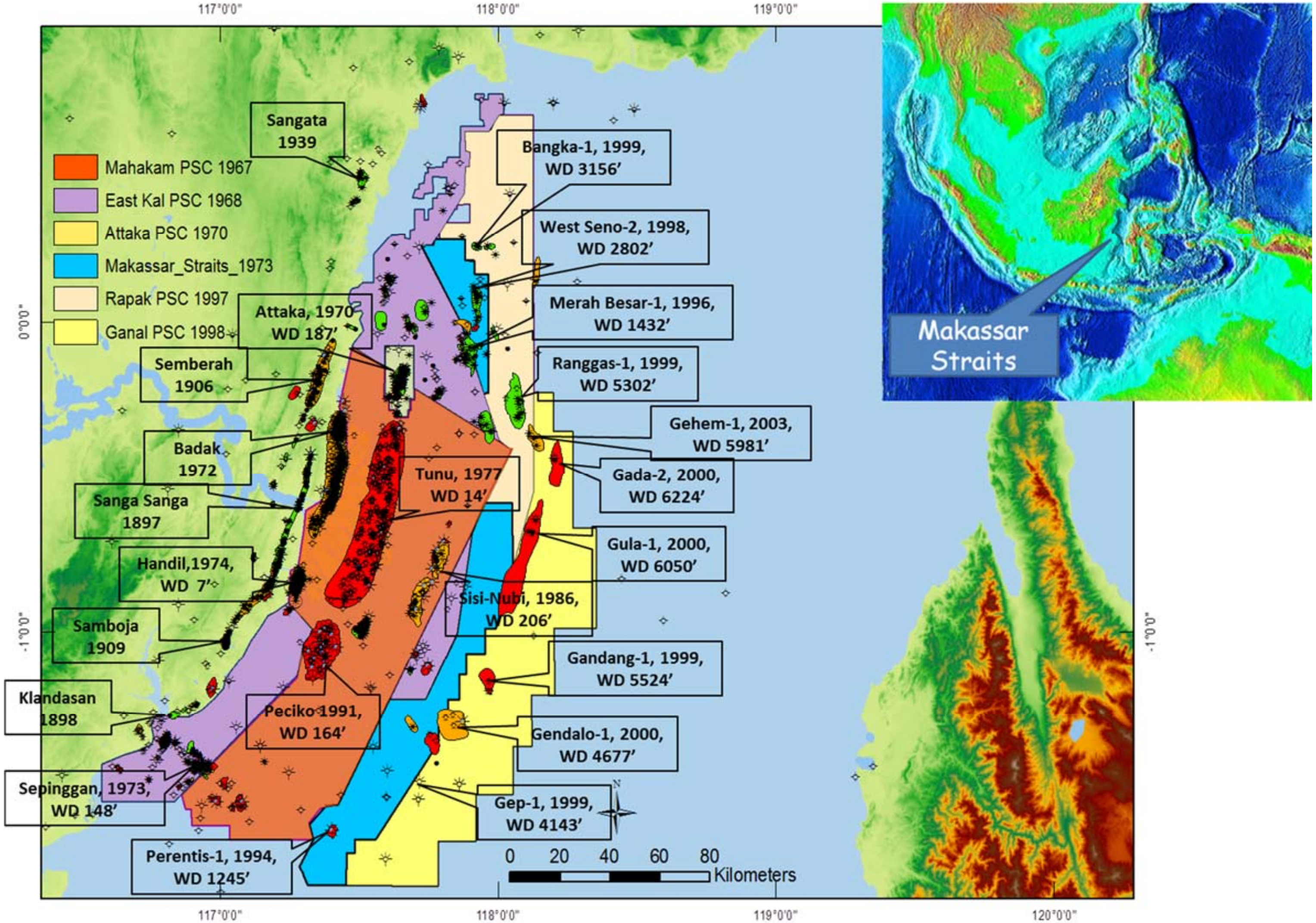

Figure 1 - Kutei Basin Exploration history progressed from West to East, into progressively more difficult conditions.

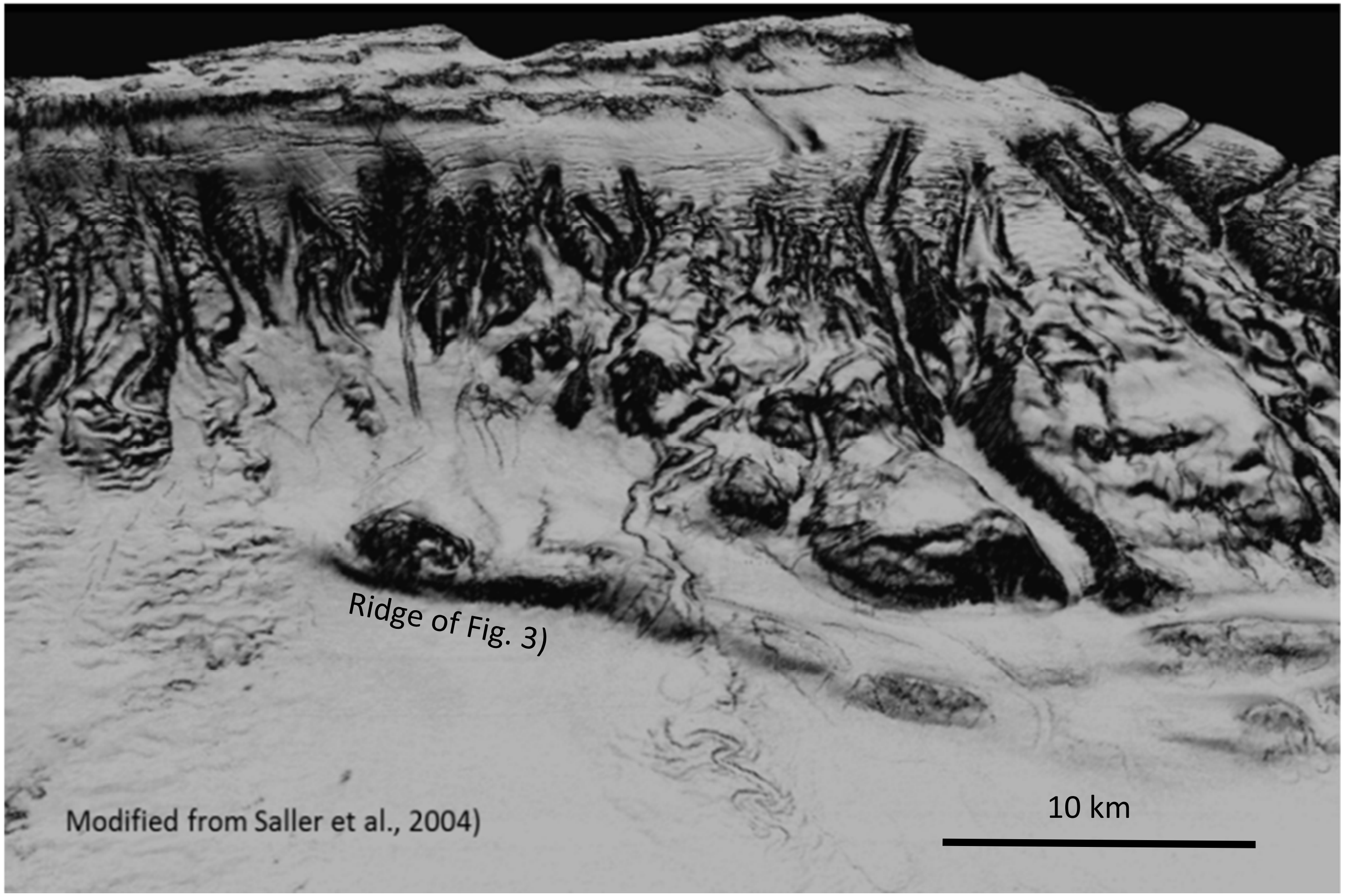

Figure 2 – Kutei shelf to slope to basin floor profile, viewed from east to west. Figure 3 shows ridge noted above.

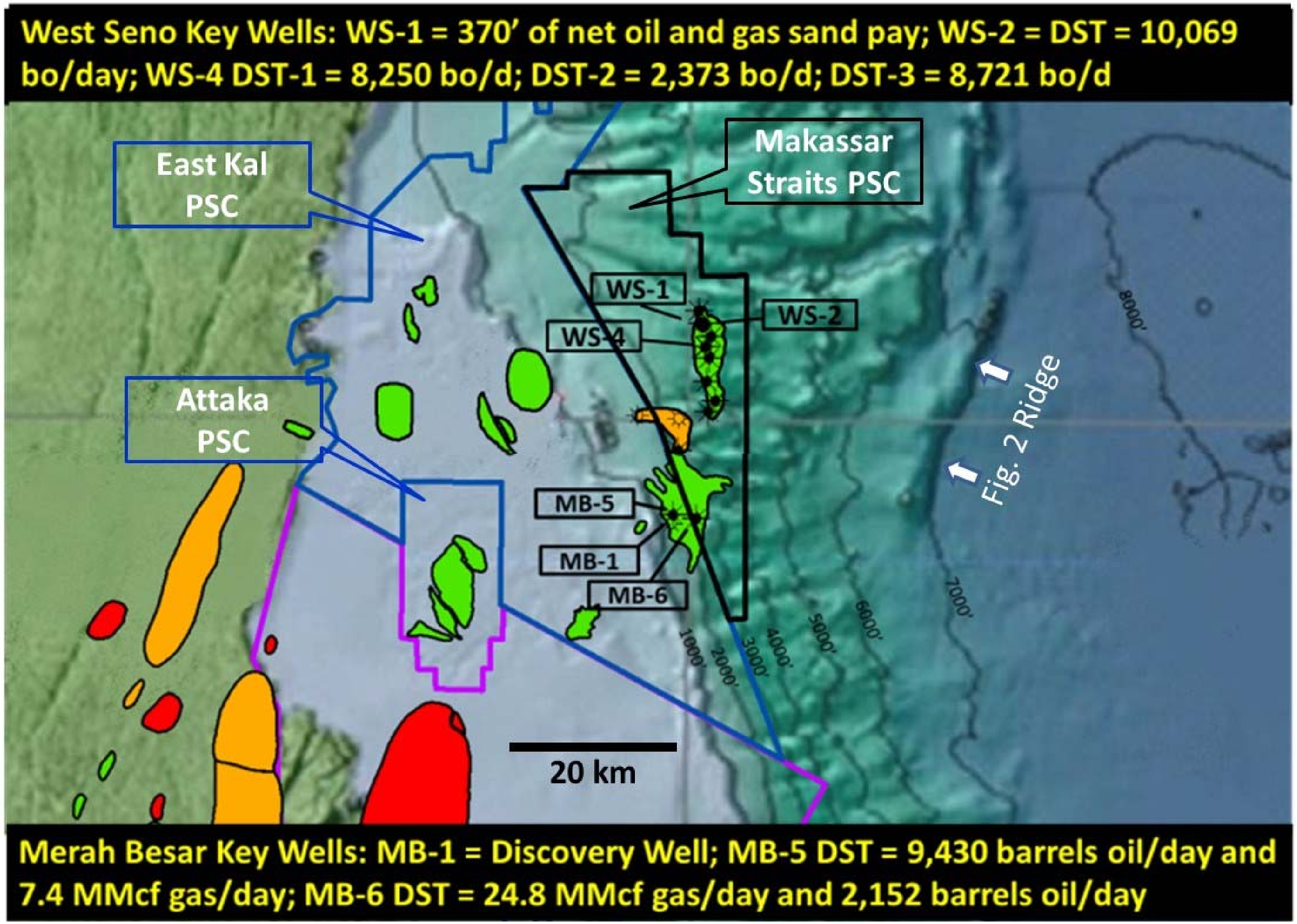

Figure 3 – Present day Shelf to Slope break with depth contours, highlighting the position of the Merah Besar and West Seno field locations and key wells.

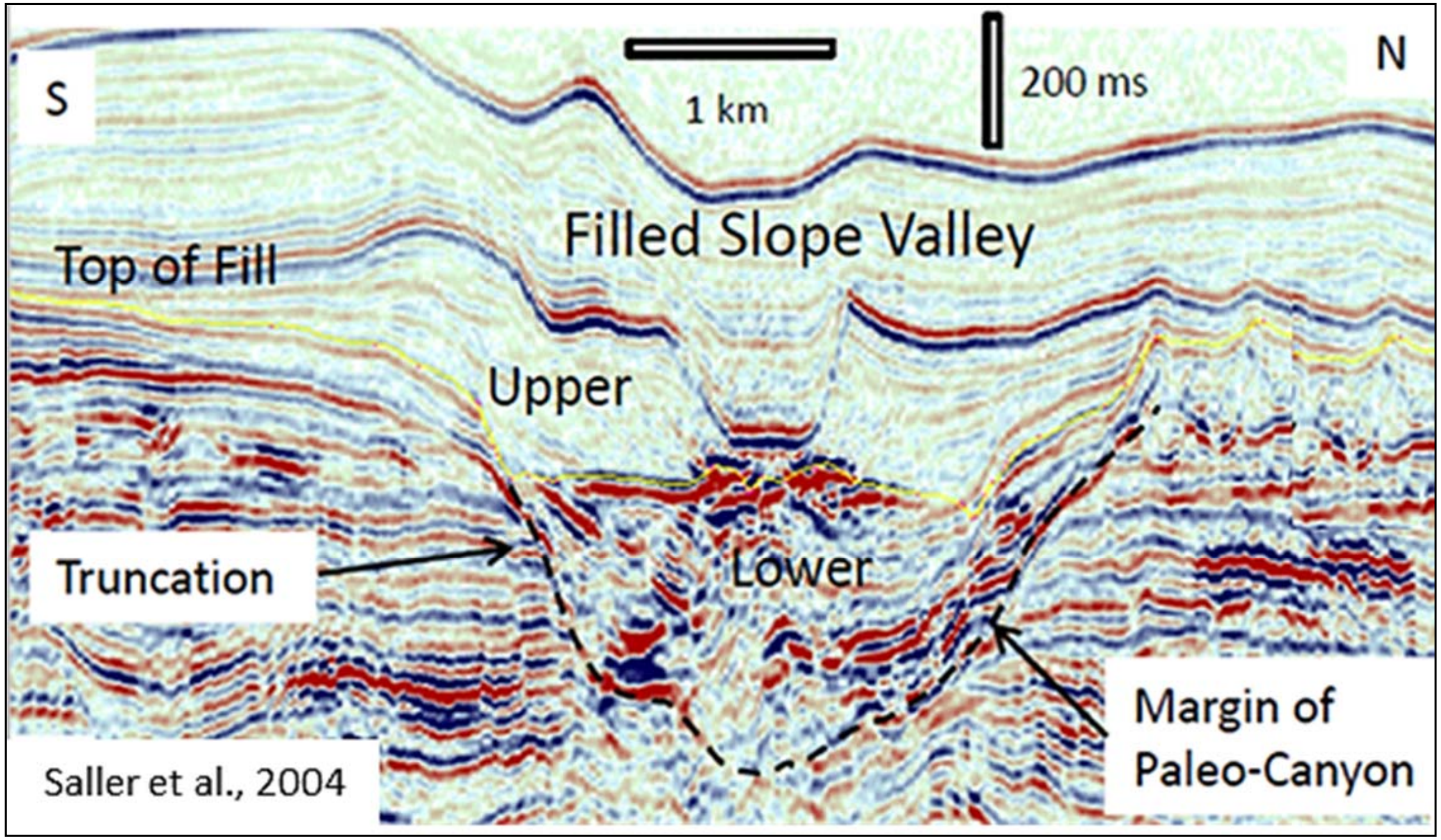

Figure 4 – Pleistocene amplitudes in channel-fills near MB-1 on Figure 3.

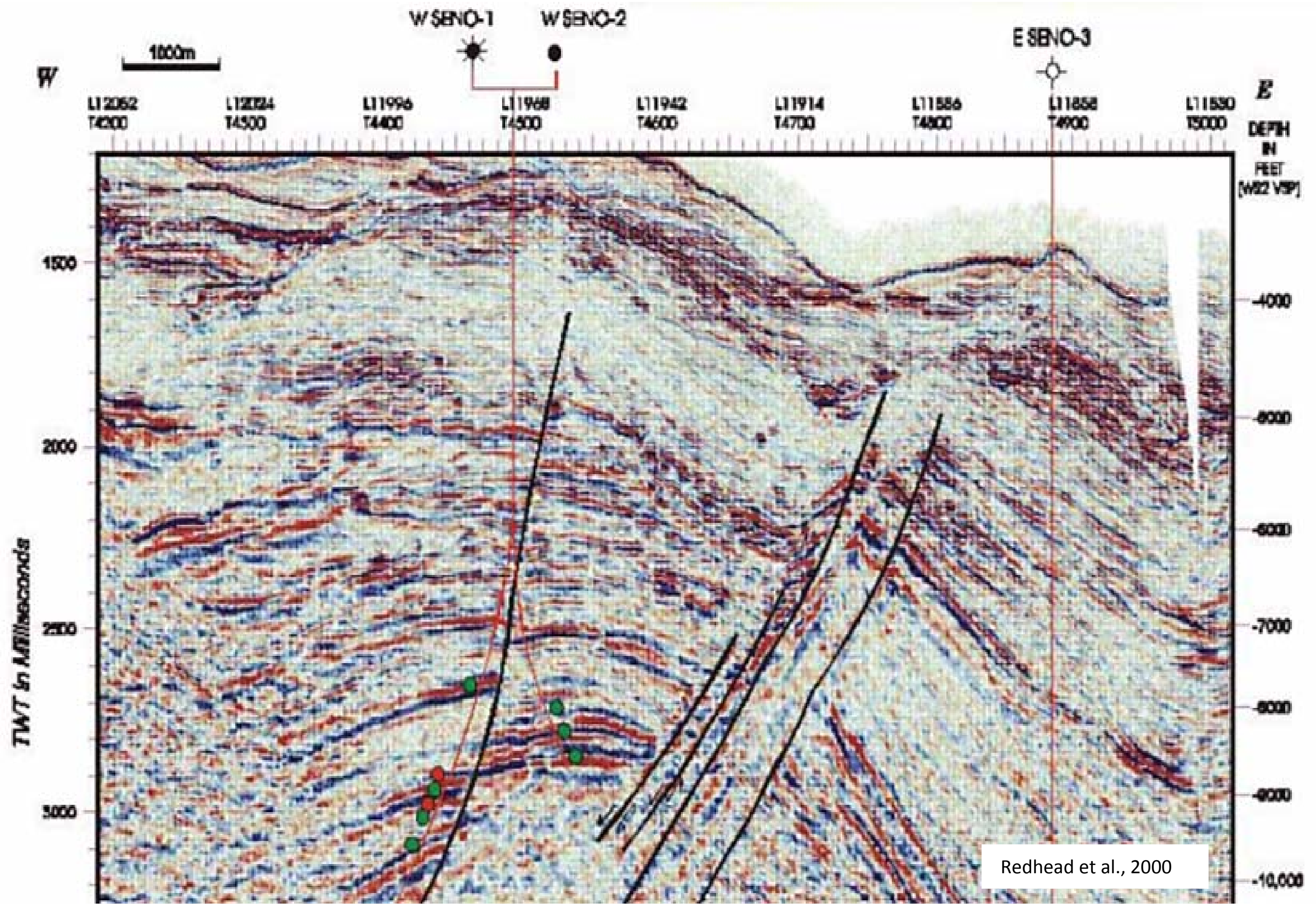

Figure 5 – West Seno seismic amplitudes are oil and gas sands.

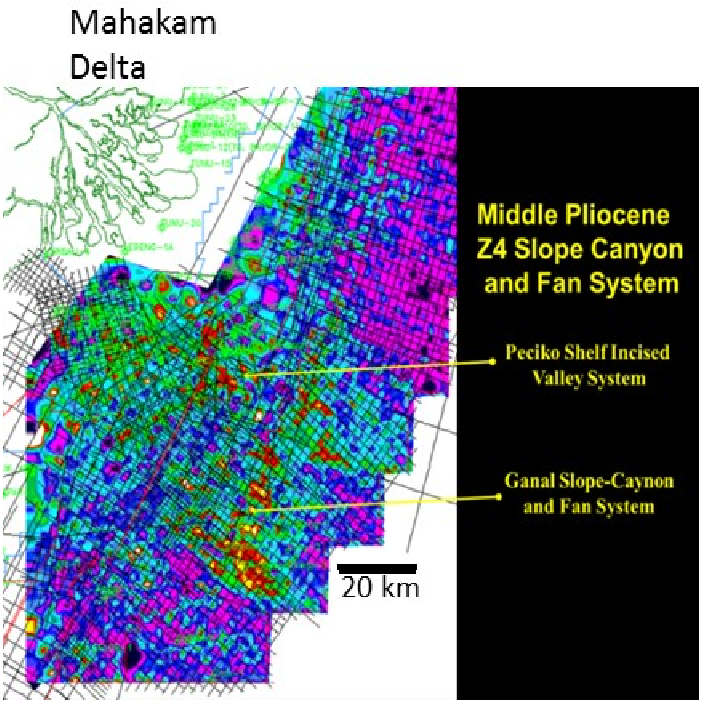

Figure 6 – 2D seismic grid spaced ~ 2 km showing bright red (negative) amplitudes interpreted as sands extending from the southern Mahakam Delta, onto the Ganal PSC.

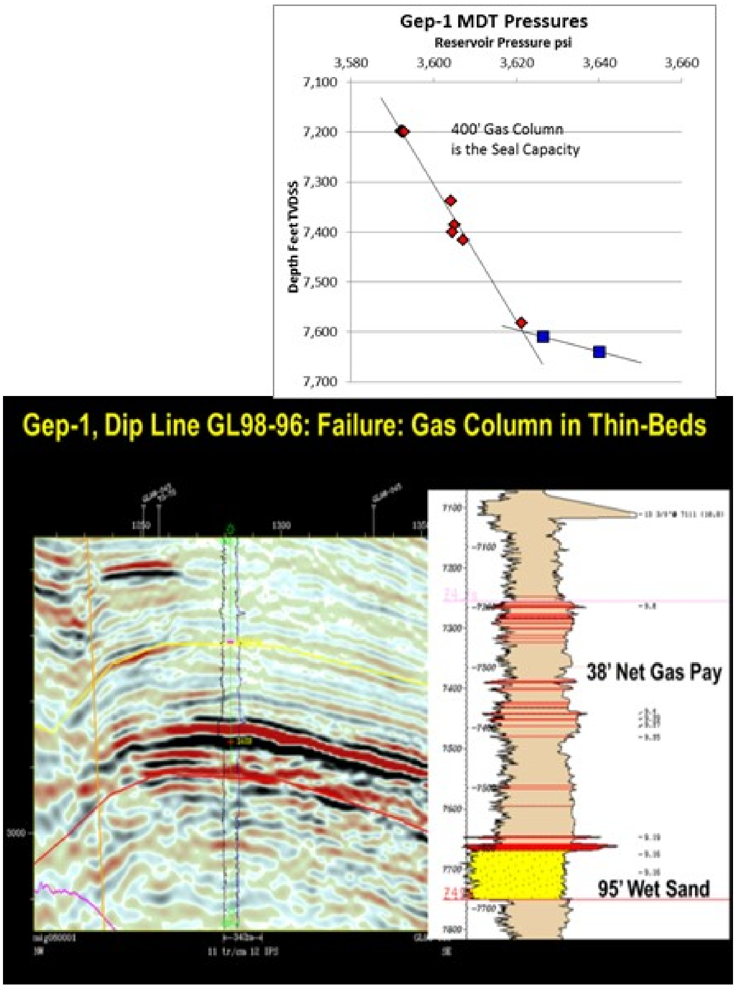

Figure 7 – 400-foot gas column in Gep-1 Gas Sands, but mostly in thin-beds.

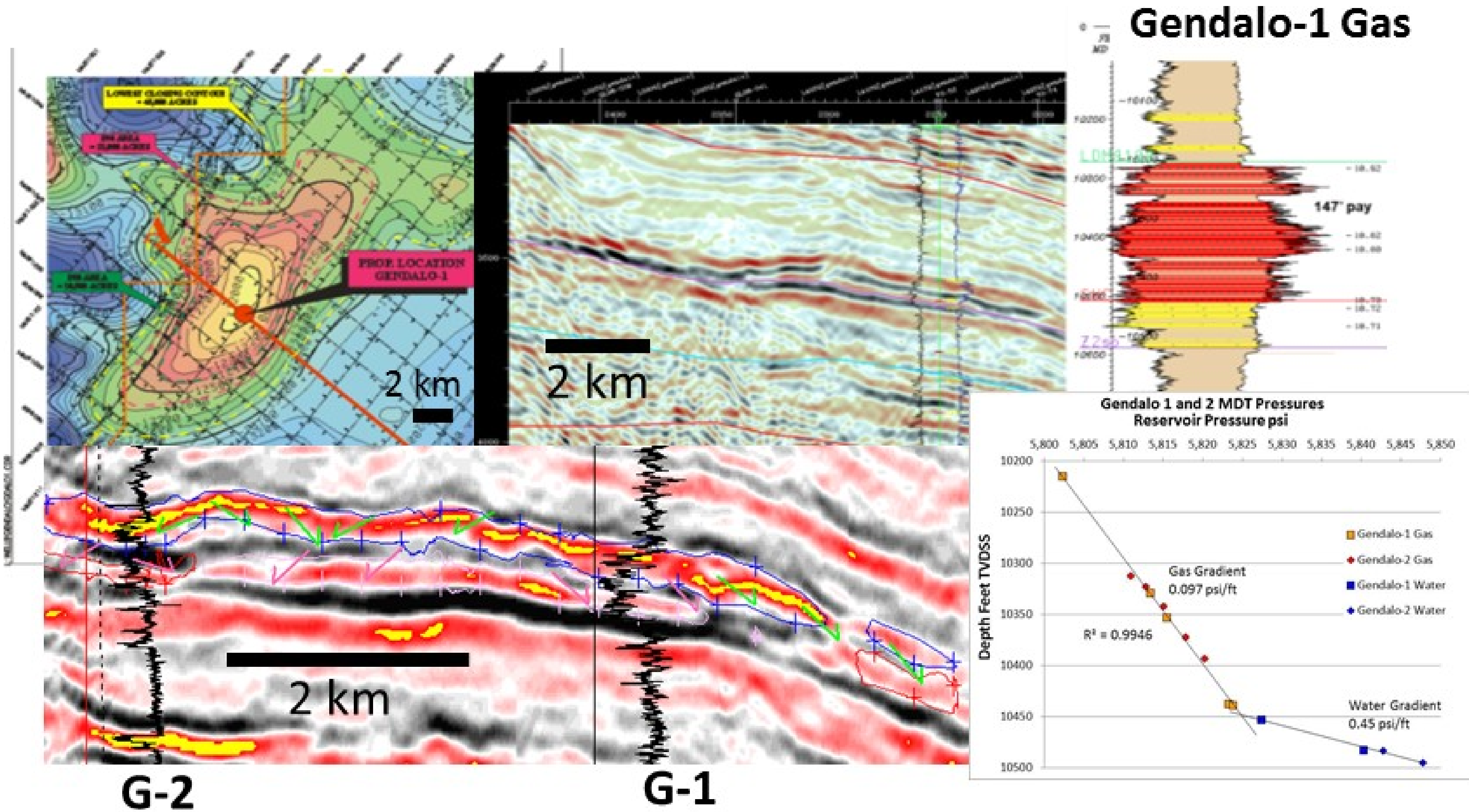

Figure 8 – Gendalo fan and gas column, Gendalo-2 and Gendalo-1 wells separated by 4 kilometers show the same gas gradient, indicating pressure communication within the submarine fan. The Gendalo structure is over 15 km in length. Gas is structurally trapped in the large Upper Miocene submarine fan.

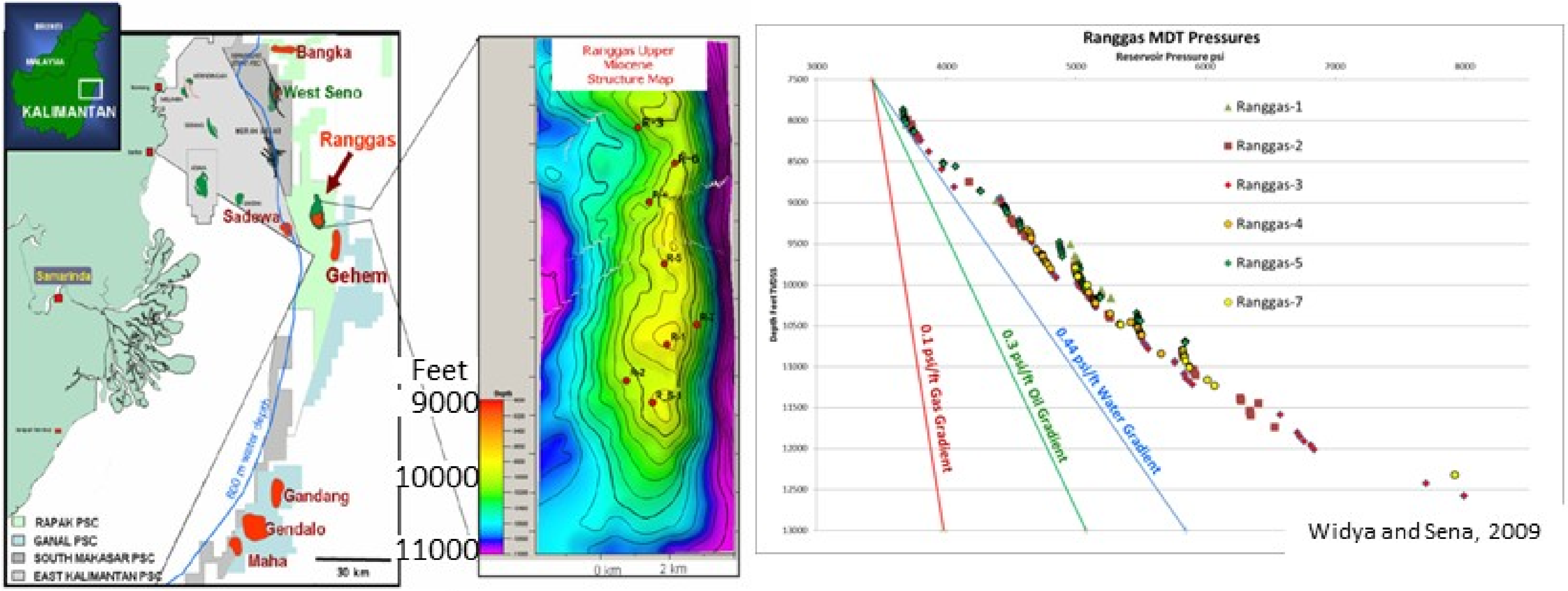

Figure 9 – Ranggas Structure and MDT pressures, see discussion in original paper by Widya and Sena (2009).

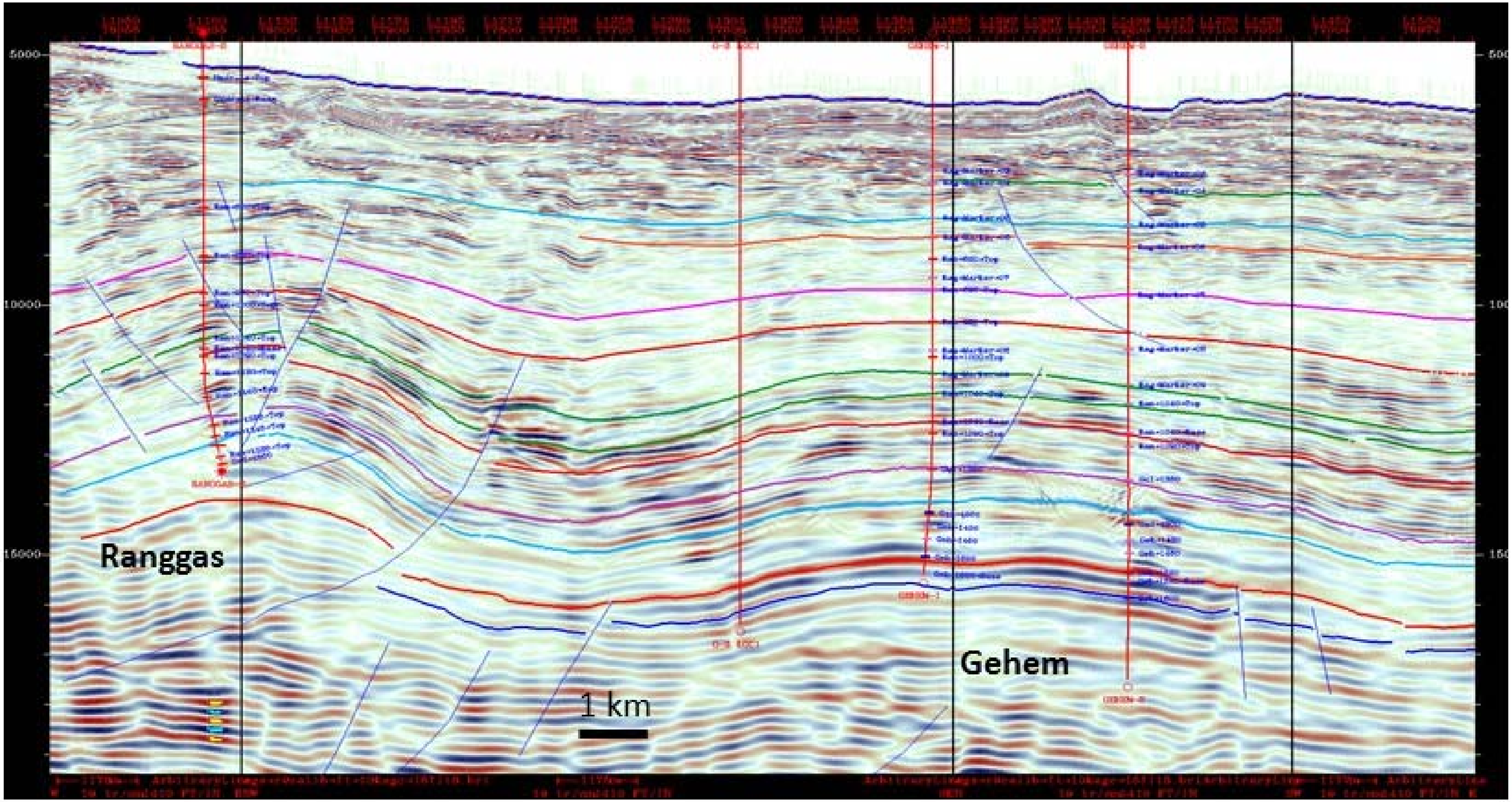

Figure 10 – Ranggas stacked amplitudes are independently trapped oil and gas sands; Gehem amplitude is an older continuous gas sand.

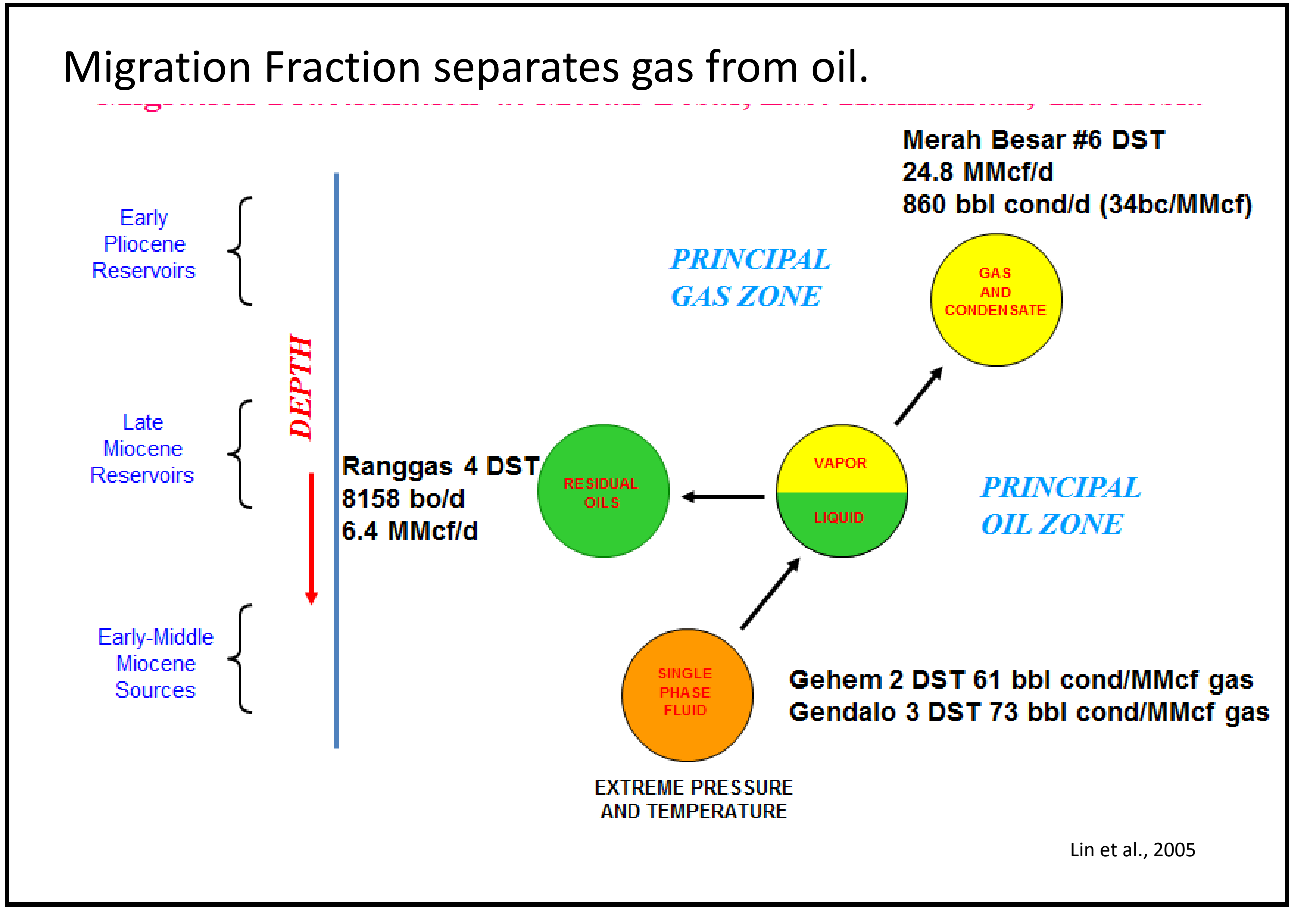

Figure 11 – The deep water Kutei Basin source rocks are sands that contain terrestrial organic matter transported into the basin coeval with sand deposition. The mix of oil and gas is due to the process of migration-fraction, which causes wet gas to separate into oil and dry gas during migration (Lin et al. 2005).

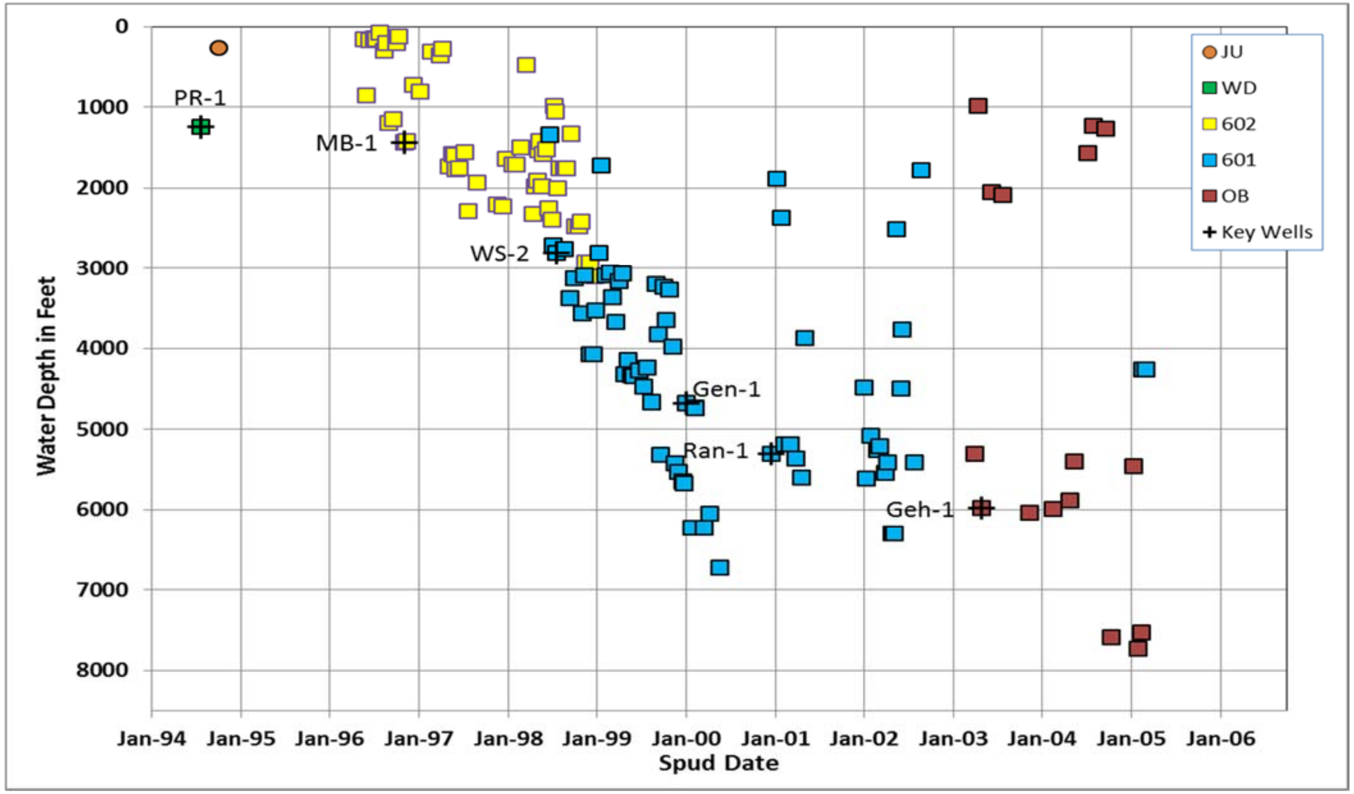

Figure 12 – Drilling innovation led to discoveries in progressively deeper water with time. Key wells are PR-1 = Perentis-1, MB-1 = Merah Besar-1, WS-2 = West Seno-2, Gen-1 = Gendalo-1, Ran-1 = Ranggas-1, Geh-1 = Gehem-1. Rigs are JU = Jack-up, WD = West Delta, 602 = Sedco 602, 601 = Sedco 601, OB = Ocean Baroness.