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Five decades of petroleum exploration and discovery in the Malay Basin (1968-2018) and remaining potential

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Abstract: Since the first oil discovery in the Malay Basin in 1969, more than 700 exploratory wells have been drilled. To date, there are more than 181 oil and gas discoveries, about half of which are currently in production and about a dozen are already in their secondary or tertiary recovery stages. In 2014 it was estimated that a total of over 14.8 billion barrels of oil equivalent (bboe) of recoverable hydrocarbon resource have been discovered in the basin, contributing to approximately 40% of the total hydrocarbon resources of Malaysia. By the end of the first decade of exploration in 1979, all the major basin-centre anticlinal structures had been tested. This play type contributed 60% of the total discovered resource in the basin. By 1981 this most prolific play type had been practically exhausted, as all the giant fields (those with recoverable resource > 0.5 bboe) had been found. As "creaming" of the basin-centre anticlinal play continued into the early 1980s, exploration efforts gradually shifted to the newly discovered western margin play types, particularly in the Western Hinge Fault Zone, Tenggol Arch and the adjacent Penyu Basin. There was a "lull" period from 1985 to about 1990, due to the global oil crisis, after which exploration was rejuvenated through significant discoveries in several play types on the northeastern ramp margin. This followed a successful drilling campaign that lasted until around 1997 and contributed an additional ~1 bboe of recoverable resources over a seven-year period. Since then, most of the incremental resource addition came from the highly gas-charged play in northern region that comes under the Malaysia-Thai Joint Development Area (JDA) and on the northeastern ramp margin, which includes the Commercial Arrangement Area (CAA) between Malaysia and Vietnam. Individually, however, the hydrocarbon volumes in these later discoveries were relatively small compared to the earlier discovered play types. Subsequently, new play types were pursued, including stratigraphic channels, deeper reservoirs beneath existing fields, high pressure/high temperature (HPHT) reservoirs, overpressured and tight reservoirs, and fractured basement reservoirs. All had some measure of success but none were able to volumetrically match the discoveries made decades earlier. As of end of 2018, over 2100 exploration and development wells had been drilled in the entire basin. Based on the creaming curve, since around 1990 and into the fifth decade of exploration, the incremental resource addition has been increasing steadily at an average rate of *ca*. 120 MMboe per year. The data indicate that the expected average discovery size would be less than 25 MMboe, and that at least 5 wells need to be drilled per year to sustain the same rate of resource addition. If no new plays are explored and no significant discoveries made, resource addition is expected to plateau beyond 2020. The basin needs a new stimulus, and more importantly, new exploration play concepts to sustain exploration business.

Keywords: Malay Basin, play types, discovery history, creaming curve, undiscovered resources, remaining potential

INTRODUCTION

The Malay Basin, located offshore east of Peninsular Malaysia, is the most prolific oil and gas producing basin in Malaysia, contributing about 40% of the country's total hydrocarbon resources to date. It is also, without doubt, the most explored region in the country. After more than five decades of exploration, a wealth of seismic data, both 2D and 3D, have been acquired, covering almost the entire basin (Figure 1). Since the first oil discovery in the basin was made more than fifty years ago in 1969, close to 700 exploratory wells have been drilled. If all development and production wells are included, the total number is well over 2100.

Despite the many discoveries made during the last several decades, the incremental resource addition resulting from those discoveries has been relatively small or "marginal" (generally less than 30 MMboe[2]). The rapid advances in exploration technologies and extensive

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[2] In this paper, units of hydrocarbon volume are given in either MMbbl – million barrels, MMboe – million barrels of oil equivalent, bboe – billion barrels of oil equivalent, and tcf – trillion cubic feet (of gas). The "boe" is a unit volume of gas converted to its equivalent volume in liquid state. All the resource figures refer to the volume of hydrocarbons recoverable (EUR), as opposed to hydrocarbons initially in place (HIIP).

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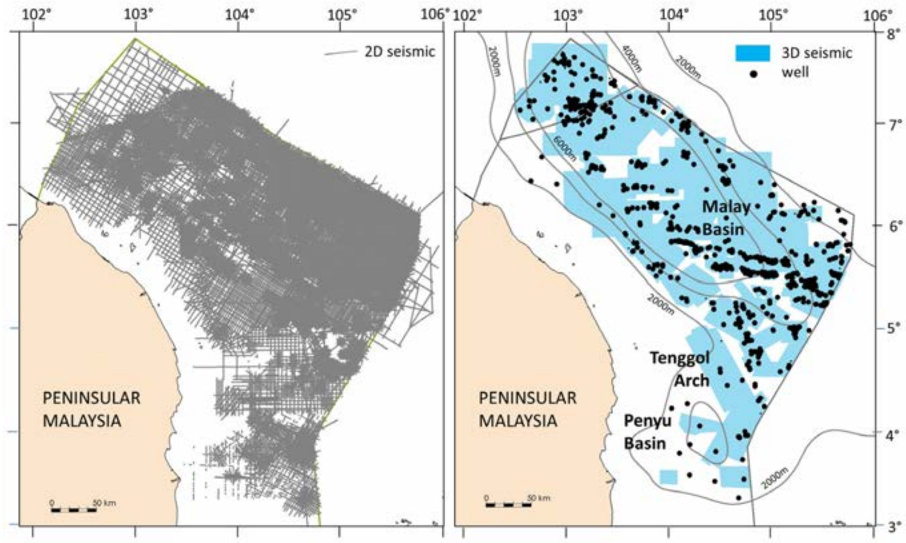

Figure 1: Maps of seismic data coverage, as of 2014, in the offshore area east of Peninsular Malaysia, including the Malaysia-Thailand Joint Development Area (JDA), redrawn and modified from Azhar *et al*. (2019). (A) 2D seismic lines. (B) 3D seismic surveys and well locations. Outlines of Malay Basin and its smaller neighbour Penyu Basin are indicated by sediment thickness contours at 2000 m, 4000 m, and 6000 m, derived from GlobSed, the global sediment thickness grid of Straume *et al*. (2019).

exploration efforts by PETRONAS and its production-sharing contractors have undoubtedly contributed to better definition and imaging of subsurface structures to reduce exploration risks. By the mid-2000s, however, the basin was perceived to be "mature"[3] (fully explored) and the chances of discovering significant volumes of hydrocarbons were considered small.

In order to sustain exploration activity and help increase the resources base[4], a "fresh" look at the basin is needed to assess its remaining potential for future investment in exploration. This paper gives a historical overview of exploration and play discoveries in the basin during the past fifty years, in the hope that it would stimulate discussion and trigger new ideas for future exploration. The study will show that the discovery history in the basin is closely linked to the different play types that were pursued during its 50-year history. This study was based on data and information available in the public domain and also aims to bridge the knowledge gap in respect of oil/gas-related information between industry and academia.

DATA COMPILATION

A major factor that prevented analysis of the exploration and discovery histories of Malaysian basins in the past is the general lack of published information, especially on the volumes of discovered hydrocarbon resources. It is therefore worthwhile to briefly review the available data and information used in this study. Early reviews of exploration activities in the Malay Basin were published by PETRONAS up to the mid-1980s (e.g., Ahmad Said, 1982; Nordin Ramli, 1985) but they generally did not include resource figures of individual fields and discoveries. In the PETRONAS book "The Petroleum Geology and Resources of Malaysia" (Madon *et al.*, 1999) there are some resource numbers but those are insufficient for a proper analysis. A more recent review of exploration activities up to 2015 by Azhar *et al.* (2019) provided more details, which include the creaming curves and drilling statistics for all the three hydrocarbon-producing basins in Malaysia – Malay, Sarawak and Sabah. This information forms a critical part of the dataset used in the present study, which include the number of exploration wells drilled per year. Although the volumetric data are not specific for individual fields or discoveries, they enabled an estimate of the annual average volume of discovered recoverable hydrocarbons to be derived.

The identities of oil and gas fields in Malaysia are available in the public domain through various sources, particularly the two PETRONAS publications, "The Petroleum Geology and Resources of Malaysia" (1999) and "Geophysical Applications in Malaysian Basin" (2019). Figure 2A shows the oil and gas fields in the basin based on the map in the 1999 book. At the time of its publication there were already around 100 oil and gas fields and discoveries and the total cumulative recoverable resources was about 13 bboe. More discoveries have been made since 1999, and by the end of 2015, the total number of discoveries had exceeded 180. The 2019 book contains an updated map of the oil and gas fields, which is reproduced in Figure 2B.

[3] The term "mature" may be confused with the state of thermal alteration of kerogen or source rocks. Hence, the phrase "fully explored" is used herein.

[4] Resources here denotes the total volume of recoverable hydrocarbons. It includes reserves (those in fields that are producing or planned for development) and contingent resources (in discoveries that are not yet commercially viable at present conditions).

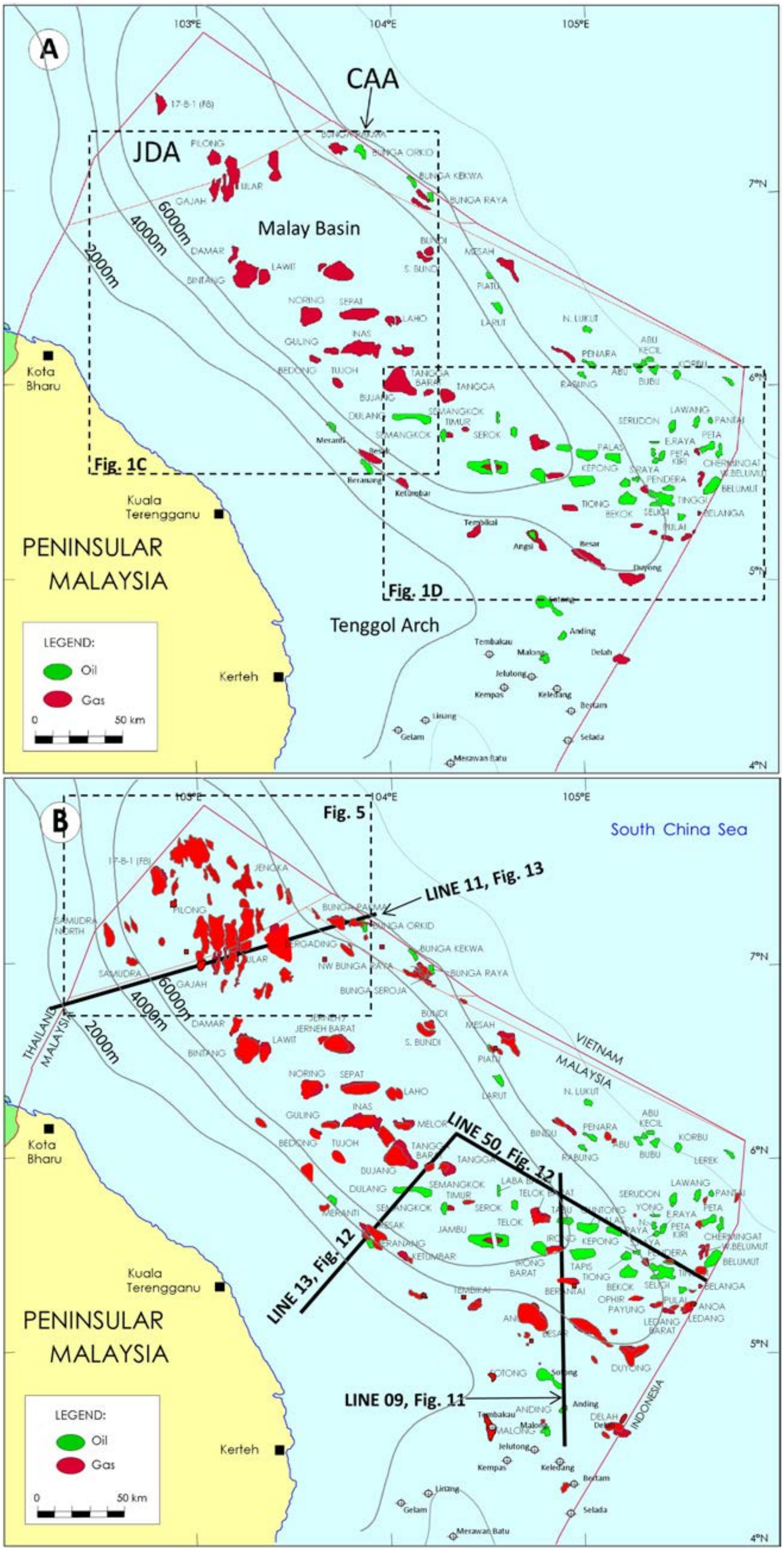

Figure 2: Maps of oil and gas fields in the Malay Basin, its outline indicated by sediment thickness contours of 2000 m, 4000 m, and 6000 m. (A) Map redrawn from the 1999 map published in PETRONAS book (Madon *et al*., 1999), with the addition of exploration wells drilled after 2000 on the Tenggol Arch. Dashed rectangles represent map areas shown in Figures 3 and 4. (B) Updated version of map in A with additional oil and gas fields discovered after 1999 compiled in this study. Bold black lines are seismic-based cross sections shown in Figures 11, 12, and 13. Dashed rectangle is close-up of JDA area shown in Figure 5.

This is the latest oil and gas map available for the Malay Basin and provides the basis for the current review. For easy reference to the oil and gas fields mentioned in this paper, smaller scale maps of the northern and southern parts of the basin are shown in Figures 3 and 4, respectively. Also included in the present study are the gas fields in the Malaysia-Thailand Joint Development Area (JDA) area in the northern part of the basin. These gas and condensate-rich fields are shown in Figure 5, which is based on information from the websites of the MTJA[5] and Carigali Hess[6].

The names and location of exploration wells in the Malay Basin (and in Malaysia in general) are available in the public domain. Exploration and appraisal wells drilled in the basin from 1969 to 1989 were listed in the once-regular feature of the AAPG Bulletin[7], "Oil and gas developments in the Far East", including their geographic coordinates. Over the years, incidental information on exploration wells was also published in several papers by PETRONAS personnel (Wan Ismail, 1984; Kader & Leslie, 1994). Global compilations by several organisations also provide the location of wells and fields in the Malay Basin; these include the USGS World Petroleum Assessments (USGS, 2000, 2019) and the heat flow database of the International Heat Flow Commission (https://www.ihfc-iugg.org/). For this review, these different datasets were compiled and verified with the latest PETRONAS oil and gas field map (Azhar *et al.*, 2019). Using GIS software, all the information was georeferenced and collated into a geospatial database for analysis.

BRIEF OVERVIEW OF EXPLORATION STATUS

The creaming curve published by PETRONAS (Azhar *et al.*, 2019**)** is a plot of cumulative discovered resources with time (year) up to 2014. It provides a history of exploration

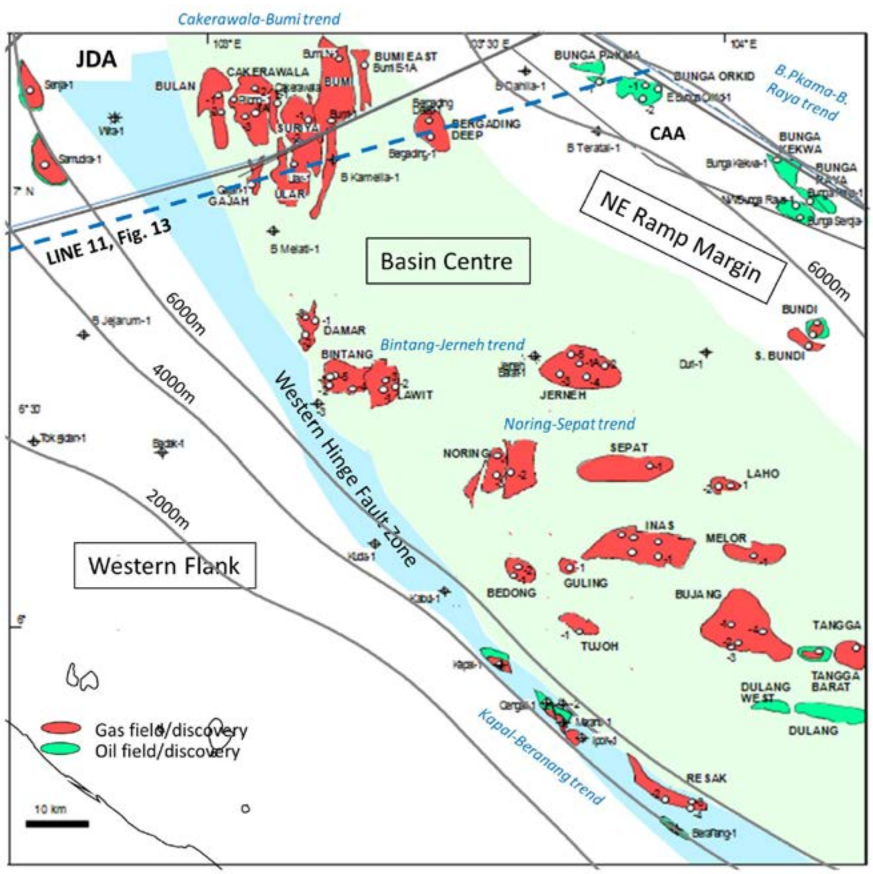

Figure 3: Map of oil and gas fields in the northern part of the Malay Basin, showing the major oil/gas trends (from Madon *et al.*, 2006). For context, see location of this map on Figure 2A. Basin outline is indicated by sediment thickness contours at 2000 m, 4000 m, and 6000 m. Blue dash line is the location of seismic section Line 11 shown in Figure 13.

[5] Malaysia-Thai Joint Development Authority website: https://mtja.org/potential.php, accessed 4 October 2020.

[6] Carigali Hess website: http://nmbffd.plmis.net/business-objective.html accessed 31 May 2020

[7] American Association of Petroleum Geologists Bulletin

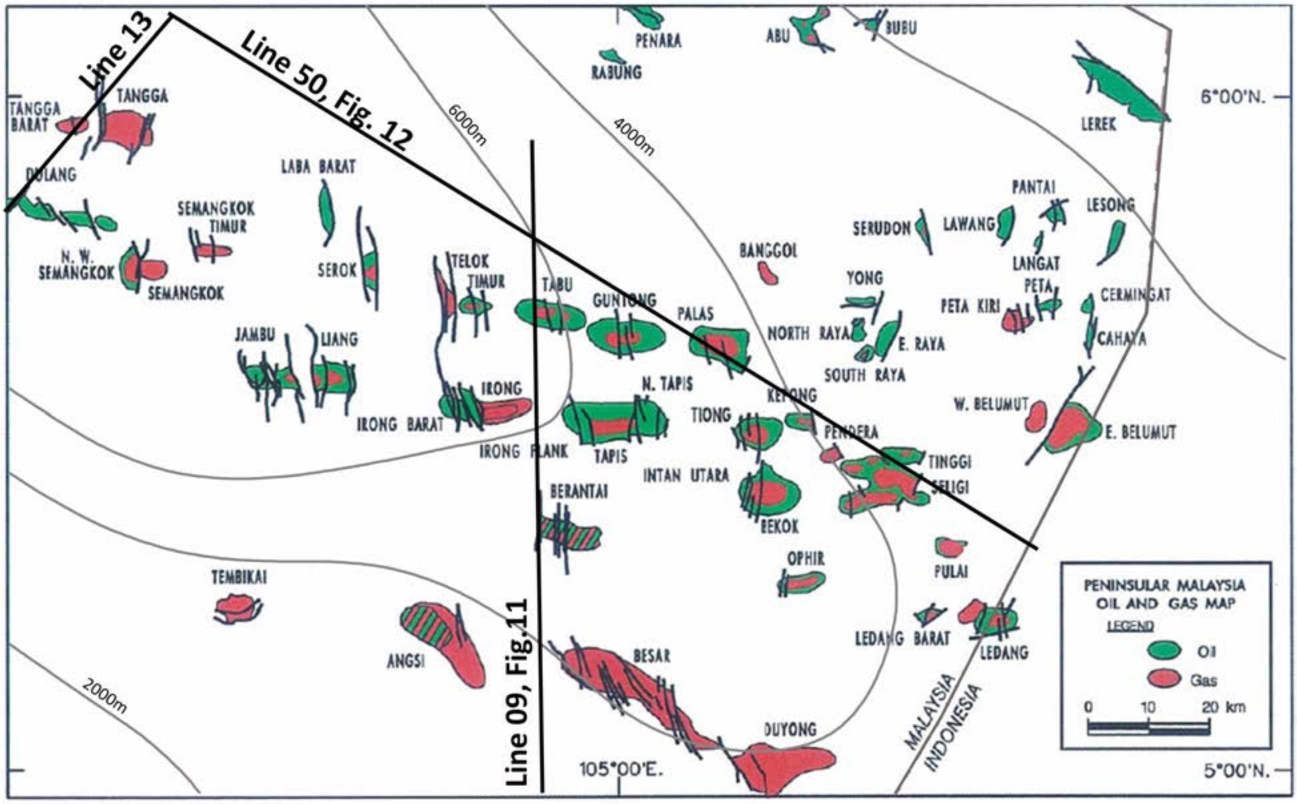

Figure 4: Map of oil and gas fields in the southern part of the Malay Basin, showing the major oil/gas trends (from Madon *et al*., 1999). For context, see location of this map on Figure 2A. Basin outline is indicated by sediment thickness contours at 2000 m, 4000 m, and 6000 m. Bold straight lines are the locations of seismic cross-sections in Figures 11 and 12.

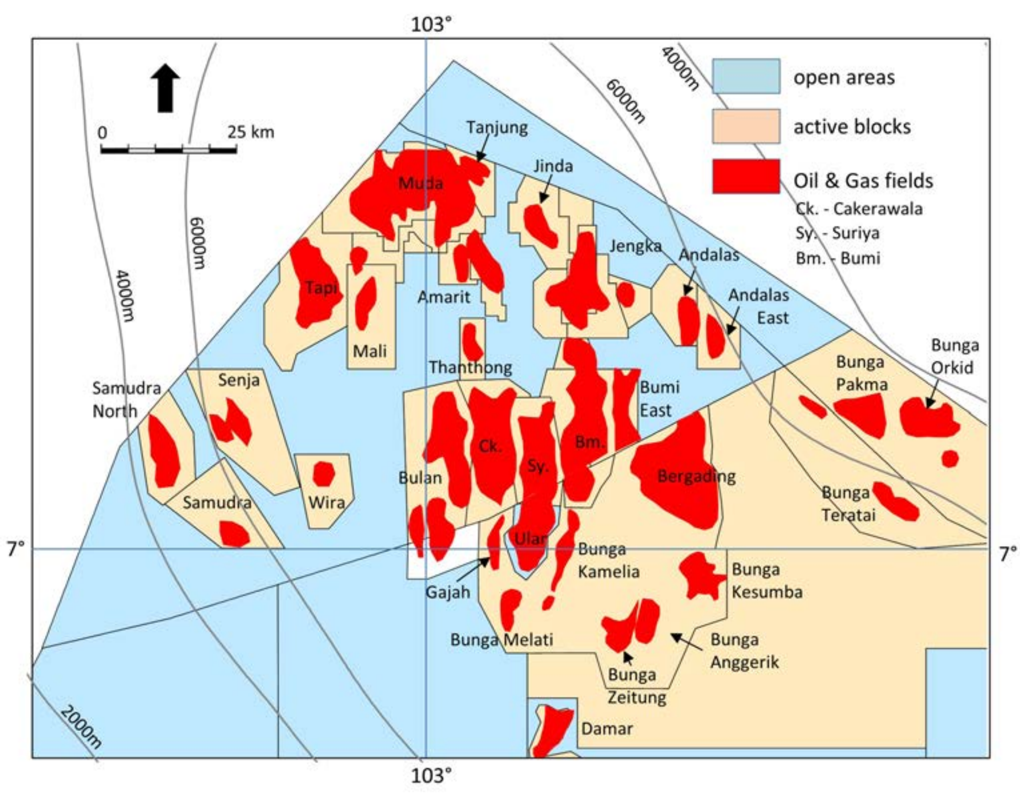

Figure 5: Map of oil and gas fields in the Malaysia-Thailand Joint Development Area (JDA), northern Malay Basin. Production block and field outlines are based on maps posted on the website of the Malaysia-Thai Joint Authority (MTJA): http://www.dmf.go.th/bid19/annaul/08.html, http://nmbffd.plmis.net/business-objective.html. Accessed 16 September 2020.

and discovery in the Malay Basin since exploration began in 1968 (blue curve in Figure 6). As is typical of basins that are at an advanced stage of exploration, the creaming curve shows an initially rapid increase in resource addition, as large fields were being discovered during the period from 1969 to 1980, followed by a much slower and gradual increase especially after 1990, as the smaller, more high-risk prospects were successfully targeted. Most interestingly, although all the giant fields (with recoverable resources above 500 MMboe) were discovered during the first decade of exploration (1968-1978), the average size (volume) of the discoveries has been diminishing rapidly since the early 1970s, within the first five years of exploration. Discovery volumes fell steadily to below 100 MMboe by the mid-1980s, and have remained relatively low for three decades since the early 1990s (red histogram in Figure 6).

The creaming curve is a strong indicator of a fully explored basin, in which discovery volumes during the latter phase of exploration are small. Major discoveries during the first two decades of exploration (1969-1989) contributed to >12 bboe in recoverable resources, approximately 80% of the total resources to date. The first 50 fields discovered between 1969 and 1985 represent an average discovery size of 230 MMboe recoverable. Compare this with 24 MMboe average discovery size for the 128 fields discovered between 1989 and 2014.

The long-term implication for the industry is that the rate of return on investment per exploration well has also been in decline. Exploration companies would normally try to drill more wells to find more hydrocarbons in order to increase the resource base. Thus, overall, we see the number of exploration wells has been increasing steadily every year during the last five decades, from less than 10 in the 1960s to more than 30 in the 2013 (Figure 7). Despite the increasing number of wells drilled, however, the discovered resource volume on a per well basis has remained low since the 1980s. Hence, drilling more wells may not necessarily result in more discoveries or greater volumes of hydrocarbons, as the expected discovery volume diminishes with time, especially if the same types of hydrocarbon play

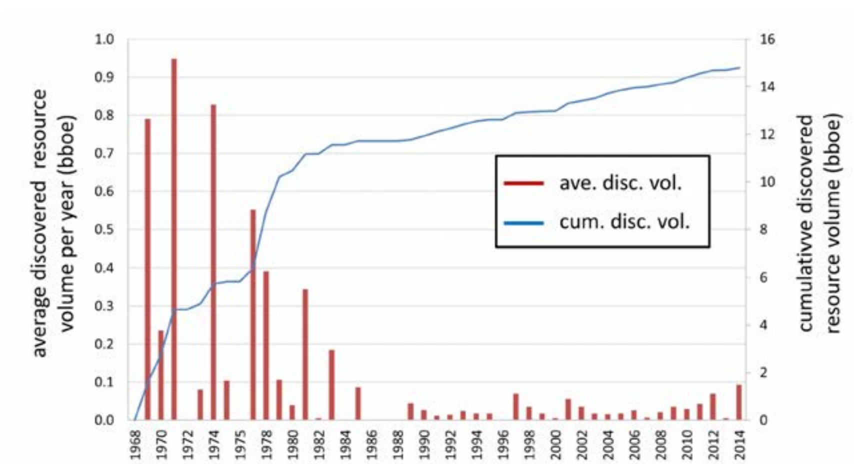

Figure 6: Cumulative recoverable resources discovered by year or "creaming curve" (blue curve, right vertical axis) and annual average discovered resource volume (red sticks, left vertical axis) for Malay Basin from 1969 to 2014. Annual average discovered resource volume (recoverable) was obtained by dividing the incremental annual resource addition (from the creaming curve) by the number of discoveries for that year. Data extracted from Azhar *et al.* (2019).

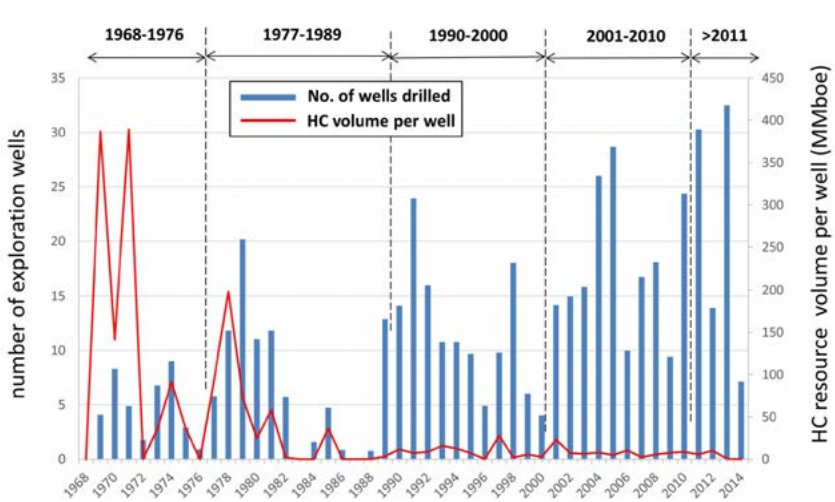

Figure 7: Number of exploration wells drilled each year (blue sticks, left vertical axis) compared with the total discovered resource volume (recoverable) on a per well basis (red curve, right vertical axis) for Malay Basin between 1969 and 2014. Volume per well was obtained by dividing annual average discovered volume by the number of wells drilled that year. Vertical dashed lines demarcate the exploration and discovery phases (EDP) discussed in the text. Total number of wells = 519. Data from Azhar *et al*. (2019).

are pursued. On the contrary, the data in Figure 7 imply that the industry had been spending more exploration dollars per barrel of discovered hydrocarbons. Drilling more wells may not be the answer, but drilling the right wells is the key. It is therefore important to review the exploration history of the different hydrocarbon play types in the basin to help assess potential new plays in the future.

GEOLOGICAL SETTING

The Malay Basin is a large NW-trending basin located entirely offshore east of Peninsular Malaysia (Figure 2). The basin is part of a Tertiary intracontinental extensional basin complex that includes the offshore Thai basins and the Penyu-West Natuna basins which seem to have developed along a major left-lateral strike-slip fault system that extends southeastwards across the present-day Gulf of Thailand towards Natuna (e.g., Morley, 2002). The Malay Basin was initiated by extension during Late Eocene-Early Oligocene times and underwent anomalously high post-rift thermal subsidence from late Oligocene through Miocene to present-day. As a result, more than 14 km of sediments accumulated at the deepest central parts of the basin. Some authors suggested that the extremely rapid tectonic subsidence may have been the result of non-uniform crustal extension coupled with lower crustal flow (Morley & Westaway, 2006). Pre-Tertiary basement faults have had a strong influence on basin development by the formation of major E-W trending *en echelon* half-grabens along the axis of the basin (Ngah *et al.*, 1996; Madon, 1997). The hydrocarbon-bearing east-west anticlines that form the major oil and gas fields in the basin centre (Figure 4) were the result of transpressional inversion of the underlying half-grabens due to right-lateral movement along the axial basin shear zone during Middle Miocene times.

Figure 8 summarises the basin stratigraphy, depositional environments and structural events, along with the major hydrocarbon occurrences. The basin fill is subdivided into seismic stratigraphic units (called "groups") which are named alphabetically downwards from A to P (Yu & Yap, 2019). The oldest stratigraphic unit penetrated by drilling is group M (upper Oligocene) but available data suggest that the undrilled units in the deeper half-grabens could well be at least upper Eocene in age (Madon *et al.*, 2020). The depositional environments show a gradual passage from non-marine (lacustrine) through coastal plain to shallow marine, as the basin evolved from a continental

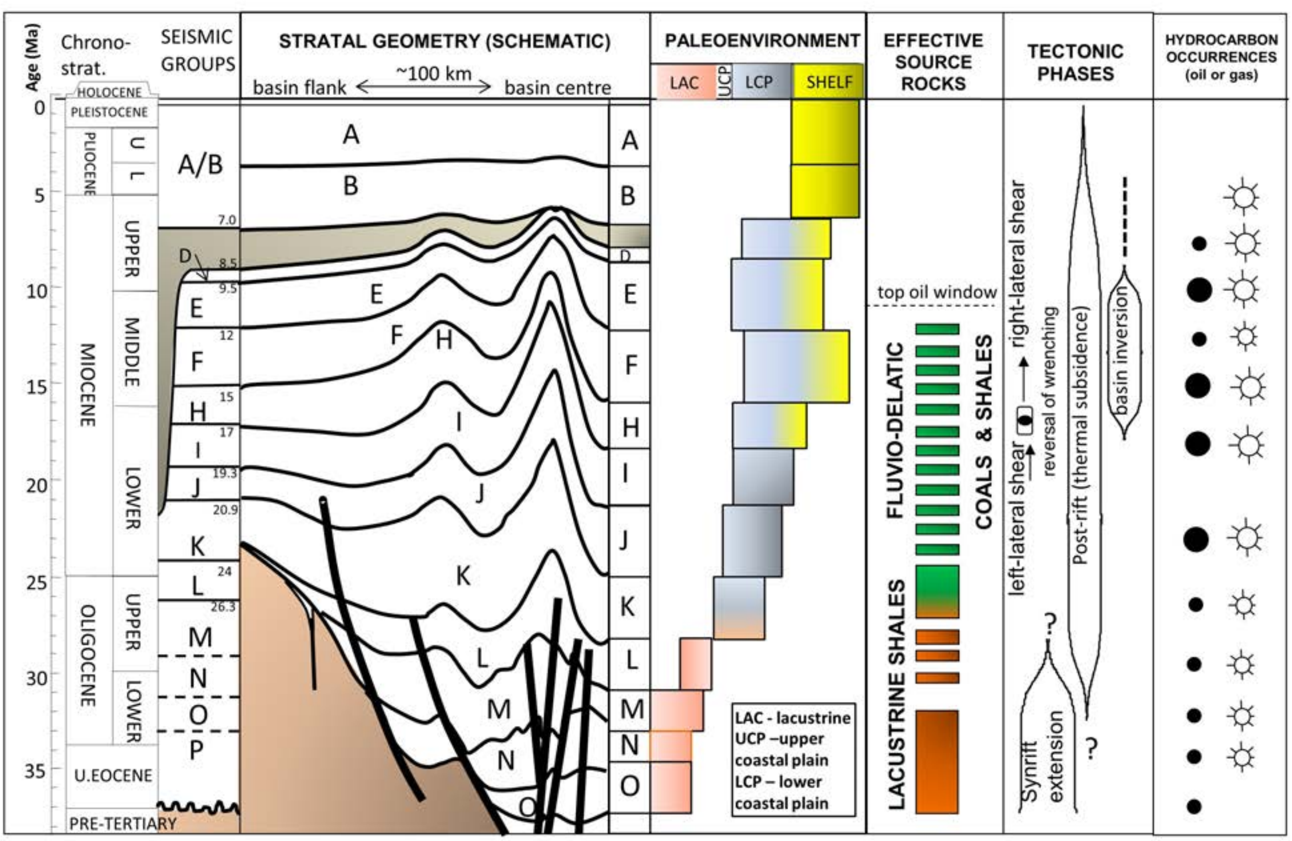

Figure 8: Summary of the stratigraphy of Malay Basin and its hydrocarbon occurrences, tectonic phases and depositional environments. Note that the K shale in the upper part of group K is often regarded as a lacustrine source rock unit but it also represents the initial transition from lacustrine to marine environment. Modified and updated from Madon *et al*. (1999, 2006).

rift to a marine basin. Biostratigraphic evidence indicates that marine incursions had occurred in the basin since late Oligocene times (group L times, according to Madon *et al.*, 2006) and that by group K times, marine conditions were well-established with the deposition of the laterally extensive 'K' shale across the entire basin (Madon, 1992). The K shale likely represents an important transition from an enclosed lacustrine basin to a more open marine basin (Figure 8). The distribution of E-W trending half-grabens within the axial basin depocentre (Figure 9) suggests that the extent of synrift lacustrine facies as the source rock (group M or older) was far more restricted compared to the postrift succession (including the K shale).

Seismic data show a relatively narrow and deep basin that gradually becomes wider and shallower, particularly towards the flanks. The basin history has been described in terms of the general rift basin model: a synrift phase of extensional faulting followed by post-rift phase of thermal subsidence that produced the broad sag basin geometry (Madon & Watts, 1998). The post-rift phase was partly interrupted by a major phase of basin inversion during early-middle Miocene, which produced the major E-W trending compressional anticlines that host a large proportion of the total hydrocarbon resources.

With regards to the main reservoir units hosting the hydrocarbons, the main contributors in terms of hydrocarbon resource volume are Group J (approximately 23% of the total of all known reservoirs), Group I (19%), Group K (15%), Group E (17%), and Group D (16%). The three main intervals (groups I, J, K) combined contributes 60%, and together with Groups D and E (25%) they contribute 85% of the total recoverable resources (Figure 10). Group J sands are the best-quality reservoirs, as they are shallow marine sands deposited in offshore wave- and storm-dominated shoreface environments (Nik Ramli, 1986). Also, volumetrically

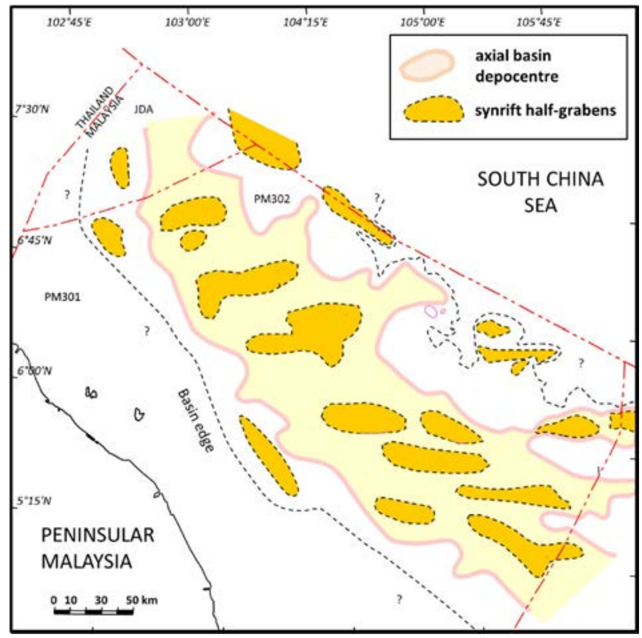

Figure 9: Distribution of synrift half-grabens in Malay Basin in the axial basin depocentre, where lacustrine source rocks were developed and had contributed a significant proportion of the hydrocarbon charge in the basin. Figure modified from Madon *et al.* (1999).

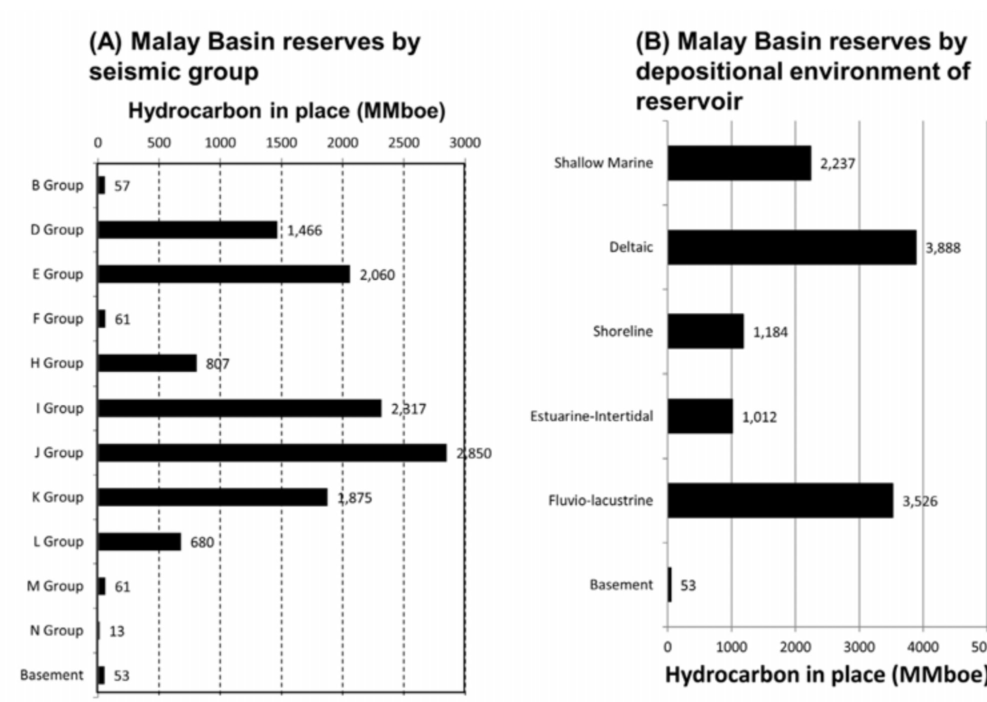

Figure10: Summary of hydrocarbon resources in Malay Basin by (A) seismic stratigraphic unit ("group") and (B) depositional environment of the reservoir interval. Data from various sources including IHS database up to 2014 and Azhar *et al.* (2019).

significant but of lesser quality reservoirs are Group K sands which tend to be texturally and compositionally immature being mainly alluvial and braided stream deposits derived from a granitic source terrain (Nik Ramli, 1988; Ibrahim & Madon, 1990). Groups I, D, and E are lower coastal plain deposits which were strongly influenced by tidal depositional processes and generally tend to be finer grained and contain more clay. Overall, however, the bulk of the hydrocarbon resources are hosted by deltaic sands, followed by fluvio-lacustrine sands, and shallow marine sands coming in third.

BRIEF REVIEW OF HYDROCARBON PLAYS

Geochemical data reveal two main types of source rocks for the Malay Basin oils: lower coastal plain (fluvio-deltaic) and lacustrine (Madon *et al.*, 1999). Most of the oils and condensates in the basin centre and on the Western Hinge Fault Zone are lower coastal plain oils, indicating that the hydrocarbon charge was mainly from the basin centre in fluvio-deltaic coal/coaly shale of groups I to H (Madon *et al.*, 2006). The main lacustrine source rocks are in the synrift sequences in the deep half-grabens in the central parts of the basin. They are mainly the Upper Eocene-Oligocene shales in groups L, M and older (Figure 8). Abdul Jalil & Awang Sapawi (2010) observed various mixtures of algal, bacterial and terrestrial components but concluded that group L shales have the highest quantity and quality of algal (type I) kerogen, whereas group K shales have relatively higher terrestrial components (type II kerogen). Besides the two main source types, the authors detected evidence for minor marine influence in oils from the most central position in the basin (Cakerawala-Bumi trend in the JDA) (Figure 5).

By the early 1980s it had been established based on the hydrocarbon distribution that the basin is essentially gas-prone in the northwest while its southeastern part is largely oil prone, as reflected in the map in Figure 2A. The major oil fields are found in the E-W trending anticlines in the southern/central part of the basin (Dulang to Palas, Desaru-Tapis/Tiong, Figure 4). Oil also occurs in faulted traps along the Western Hinge Fault Zone (Kapal to Beranang trend, Figure 3). East-west anticlinal trends in the northern axial part of the basin include non-associated gas fields such as those in the Bintang-Jerneh and Noring-Sepat trends (Figure 3) and the JDA gas fields (Figure 5). Most of the non-associated gas fields from Cakerawala to Bujang occur in groups D and E reservoirs. Oil and gas fields are also found on the NE ramp margin bordering with the Vietnamese sector of the basin (CAA area), e.g. Bunga Pakma-Raya trend (Figure 3). While most of the hydrocarbons in the northern region were probably sourced from the main basin depocentres, some of the oil/gas fields are thought to be charged by isolated source rock kitchens in the half-grabens on the basin flanks.

It is difficult to attribute the hydrocarbon accumulations in the Malay Basin to a particular source rock interval, as is normally done in petroleum systems analysis (e.g. Magoon & Dow, 1994; Doust, 2010). A reservoir in Group E, for instance, could be charged by a mixture of hydrocarbons that migrated from Group I source rocks as well as from deeper intervals in the K and L groups at the basin centre (Madon *et al.*, 2006). Hence, in the present review, the oil and gas discoveries are classified into “operational play types” which are based on a combination of structural type and location within the basin. It should be noted that these are not “true” plays according to the strict definition used in petroleum systems analysis (cf. Doust, 2010), but nevertheless this classification provides a practical basis for the present discussion of the exploration history. The play types are designated as P1 to P9 (Table 1) and their geological occurrences are illustrated in the regional cross-sections in Figure 11 through Figure 13.

Table 1: Main play types in Malay Basin, some examples and figures in this paper for reference.

Code	Play type	Field examples	Figures
P1	Basin centre anticline and related traps	Tapis, Tiong, Kepong, Jerneh, Inas, Dulang	Fig. 11, Fig. 12
P2	Basin centre fault related traps	Gajah, Ular, Cakerawala, Bulan, Bumi	Fig. 13
P3	Normal fault traps and other fault-dip closures	Bergading, Melor, Laho, Abu, South Raya, Sotong,	Fig. 11
P4	Eastern half-graben	Bunga Pakma, Bunga Raya, Mesah	Fig. 13
P5	Western Hinge Fault Zone traps	Resak, Beranang, Kapal, Kuda	Fig. 12
P6	Western flank and Tenggol Arch	Malong, Bertam, Tembakau,	Fig. 11. 13
P7	Fractured basement	Anding	Fig. 11
P8	Stratigraphic traps and channel play, amplitude anomalies	Bindu, Bunga Seroja	Figs. 11, 12, 13
P9	Deep reservoir, HPHT (including tight sands and synrift play)	Bergading Deep, Sepat Deep, Guling Deep, Gansar	Figs. 11, 12, 13

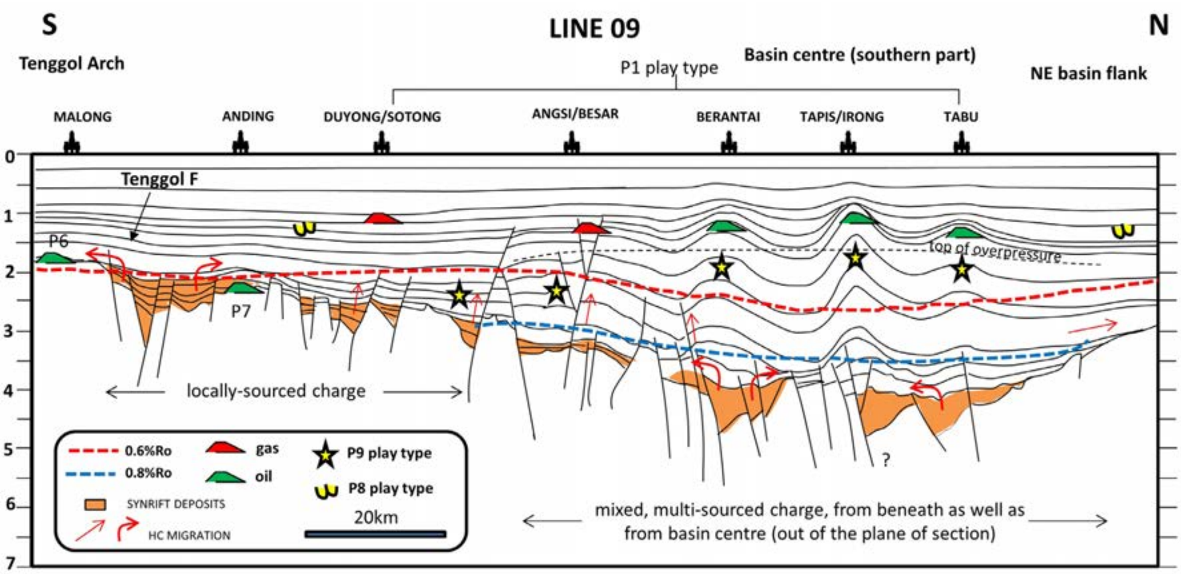

Figure 11: Sketch of regional seismic Line 09 across the southeastern part of the Malay Basin, showing the main structural styles and play types. Compressional anticlines represent P1 play type at the basin centre (Berantai, Tapis/Irong, Tabu, Angsi) which contrasts with essentially undisturbed post-rift strata on the flank to the south (Tenggol Arch). Highlighted in orange are synrift packages in the deep half-grabens which provide some of the hydrocarbon charge to the structures above and up the flanks. Much of the charge to the compressional anticlines, however, was probably from the deep basin depocenter to the west of this profile (out of the plane of section; see line location in Figure 2B). Besides P1 play type, other main play types shown, i.e. P6, P7, P8, and P9. This schematic cross-section was redrawn and modified from Mansor *et al.* (2014).

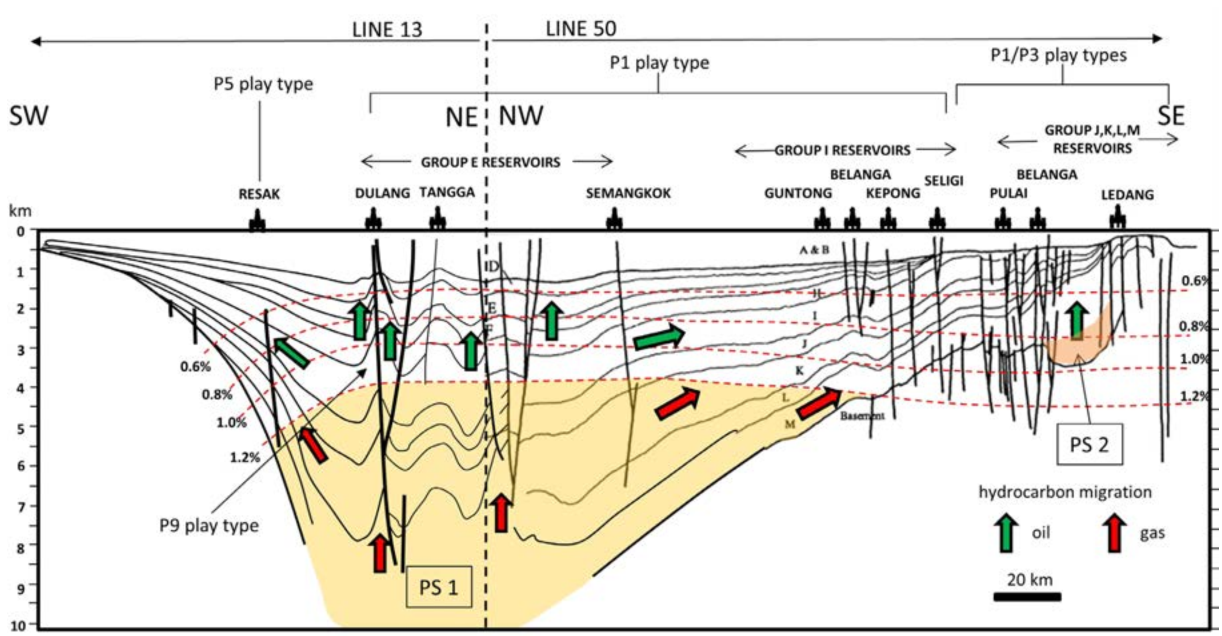

Figure 12: Composite geological cross-section of Malay Basin from the SW flank to basin centre, along Line 13 towards Dulang and Tangga fields to NE. The line joins with Line 50 from the basin centre to SE crossing the main oil fields from Semangkok to Ledang. See location of profiles in Figure 2B. Red dash lines represent vitrinite reflectance contours. Two main petroleum (charge) systems are operating: PS1 at basin centre - vertical migration from deep kitchens via faults, lateral migration via carrier beds (red arrows) to fill the mostly Group E reservoirs. PS2 at southern end where oil fields dominated by Group I, J, K, L and M reservoirs were charged mainly from local half-grabens. The gas fields in the centre have a mixed source, oil from mainly Groups H and I (which are at peak generation stage) and gas from J and deeper units. Figure modified from Madon *et al.* (1999).

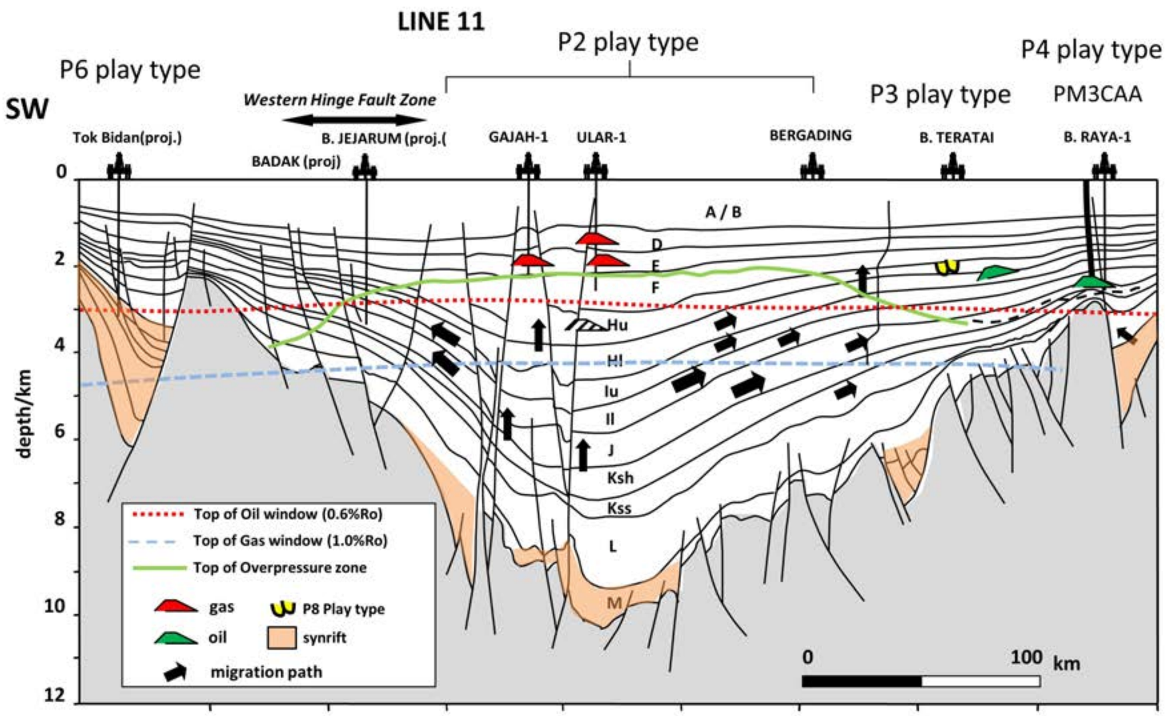

Figure 13: Cross-section based on seismic profile Line 11 which crosses the northern part of Malay Basin basin parallel to the southern boundary of the JDA, passing through Gajah, Bergading and Bunga Pakma gas fields (see Figure 2B for line location). Geologically, the line crosses the northern subbasin which has a north-south structural grain instead of E-W, unlike in the main basin to the south. The N-S basement-involved wrench faulting is more intense, and many faults penetrate the shallower section (units D and B). Figure modified from Madon *et al.* (2006).

Figure 11 shows a N-S oriented profile across the southern Malay Basin based on interpreted regional seismic Line 09. It shows the structural style through several of the compressional anticlines (P1 play type) that form the oil/gas trends mapped in Figure 4, namely: Tabu, Tapis/Irong, Berantai, Angsi/Besar, and Duyong. Further south, the profile crosses Sotong and Anding structures near the Tenggol Fault and the Malong structure on the Tenggol Arch (Figure 2B). On the basin flanks, the effect of transpressional inversion was insignificant as no folding of the postrift strata is apparent. Hydrocarbon charge to the anticlinal traps in the central part of the basin were probably from source rocks in the underlying kitchens, including the half-graben basins which are within the oil window. As Line 09 obliquely crosses the southern edge of the main basin trough to the west of the main anticlinorium, a significant part of the hydrocarbon charge could have also come from the deeper basin-centre kitchen the west (which is out of the plane of this cross-section). As for the structures in the southern part of this profile, the main hydrocarbon charge is likely to have come directly from the half-grabens beneath the structures with minor input from the basin-centre kitchen by long-distance migration.

Models of the petroleum systems in the basin have been presented previously (Madon *et al.*, 1999, 2006). The two main petroleum systems are illustrated in Figure 12 which is a composite cross-section based on regional seismic Line 13 and Line 50 (see Figure 2B for location). Petroleum system PS1 is in the central part of the basin and is dominated by oil and gas derived from generative source rocks in the deep basin-centre kitchens. Due to the large volumes of gas generated from these kitchens, much of the oil accumulation occurring immediately above them may be subject to flushing by the incoming gas. Petroleum system PS2 occurs in the southern part of the basin where, due to regional basement uplift, the main source rock units are still within the oil generation window and therefore are likely to fill the overlying traps mainly with oil.

Hydrocarbon source rocks in the Malay Basin are not limited to specific intervals or units but are interbedded with the lateral equivalents of the reservoir formations in the synclinal areas or deep half-grabens where they attained generative maturation levels. Shales ranging from group H down to P are believed to have contributed to the hydrocarbon charge in different parts of the basin. The main source rock shales currently within the oil-generating window are thought to be mainly in groups H and I. Based on a vitrinite reflectance threshold of 0.6% the depth to the oil window at the basin centre is about 2 km (Madon *et al.*, 2006). Hence, most of the sedimentary units (groups H and older) at the basin centre are thermally mature, and therefore contain generative source rocks that may have charged the overlying traps, which are mainly in groups D and E.

Due to the huge thickness of sediments in the basin centre, groups K and older source rocks are probably in the gas generation stage. Since the entire central basin region is underlain by at least 8.5 km of sediments, this explains the gaseous nature of the accumulations at the basin centre, from Tangga all the way northwestwards into the JDA area. In addition, the deeply buried source shales contributed significant volumes of the CO_2 ‘contaminant’ in the central part of the basin. It is believed that the large amounts of thermogenic gas generated in the deep basin centre may have flushed out much of Group H oil that may have initially filled the D and E reservoirs in the anticlinal structures above (Figure 12). Alternatively, since in most parts of the basin (especially in the centre) oil generation from Eocene-Oligocene synrift lacustrine shales probably took place before the mid-Miocene inversion event created the traps, and the hydrocarbons may have migrated out to the flanks and southeast. The source rocks there were (and are) still in the oil window since the newly-created traps were formed. Elsewhere, from earliest Miocene time onwards the sequence contains source rocks that are overwhelmingly gas-prone, and the exceptional postrift subsidence ensured that many of these were mature and charging upwards during and following structural formation (see Madon *et al.*, 2006, for a discussion on source rock maturation history).

In addition to the main petroleum systems described above, on the basin flanks the hydrocarbon charge is likely to come directly from the underlying half-grabens. Hydrocarbons may have also migrated laterally up the flanks and trapped along the faulted basin margins (P3 play type, Table 1). On the western margin, there is a particular type of traps associated with the Western Hinge Fault Zone (P5 play type), such as those in Resak and Beranang fields (Figures 12, 13). On the northeastern flank, lacustrine oils were found in the Bunga Pakma-Raya trend on the northeastern flank; these were charged from adjacent half-graben systems (Madon *et al.*, 2006), similar to the hydrocarbons found to the northeast across the border with Vietnam (Peterson *et al.*, 2011). They are referred to here as the Eastern half-graben play type (P4) (Table 1).

Generally, the compressional anticlines (P1 play type) tend to be oil-rich in the southern part of the basin whereas in the north, most of the structures are gas-prone. This is especially the case in the JDA area where the traps are formed by intensely faulted N-S structures in the axial part of the basin, and are referred to as basin-centre fault-related traps (P2 play type, Table 1). Figure 13 shows Line 11 which crosses the northern part of the basin almost coinciding with the southern boundary of the JDA. It passes through Gajah, Bergading and Bunga Pakma gas fields. Geologically, Line 11 crosses the northern sub-basin which has a north-south structural grain, parallel to the Gulf of Thailand structure, instead of E-W as in the main Malay basin to the south. The basement-involved N-S strike-slip faulting is more intense, and many faults cut through the shallower seismic groups D and B. As is the case for the central southern region (Figure 12), the over-mature source rocks in the deeper parts of the basin (groups K and below) may have contributed significantly to the gas accumulations by replacing the liquid hydrocarbons derived from the shallower source horizons (H and I). Along with the large volumes of thermogenic gas is a significant percentage of CO_2 from both organic and inorganic sources (Madon *et al.*, 1999).

CREAMING CURVE AND PLAY HISTORY

Creaming curves provide a snapshot of the exploration history of a petroleum basin. The creaming curve of the Malay Basin (Figure 6) represents five decades of exploration and discovery since 1968. Coupled with information on play types, the creaming curve can give insights into the exploration history and strategy undertaken by oil companies and the governing authority that manages exploration activities. In Figure 14A it can be observed that the steep rise in resource addition during the first two decades of exploration (up to around 1982-83), comprises at least two couplets of “a steep rise in resource addition followed by a plateau”, each lasting about 10 years; 1969-1976 and 1977-1989. In contrast, the three decades since 1990 are characterized by a remarkably linear creaming curve with a near-constant increase in cumulative resources, implying that incremental resource addition has been constant at a rate of about 120 MMboe per year. Furthermore, it seems that the curve has not reached a plateau, and this trend may well continue into the near future if exploration activities were to continue at the same rate. Unfortunately, no data beyond 2014 were available.

Based on the creaming curve, drilling history and discoveries (Figures 6 and 7), the exploration history of the Malay Basin may be summarized into 5 main exploration/discovery phases (“EDP” in short), each lasting for approximately 10 years (Figure 14A):

1968-1976
1977-1989
1990-2000
2001-2010
2011-2018

The first two EDPs are each characterized by a rise-plateau couplet. It could also be argued that the first EDP comprises at least two smaller rise-plateau couplets of shorter durations of about 3 to 5 years each (Figure 14A). The rapid rise at the start of each phase is attributed to a “key” discovery, which is not necessarily the biggest volumetrically but had a key role in opening up a new exploration play. Tapis (discovered in 1969) was the first key discovery for the compressional anticline play (P1) but Seligi (1971) and Guntong (1978), also of P1 play type, were the two biggest fields in terms of hydrocarbon

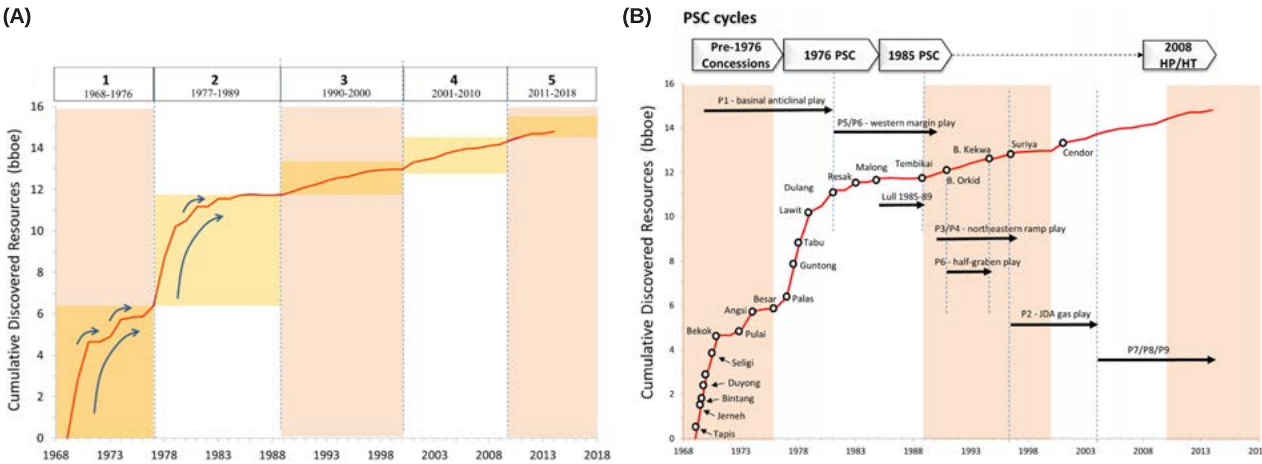

Figure 14: Malay Basin creaming curve. (A) Cumulative discovered (recoverable) resources in the Malay Basin from 1968 to 2014 based on the creaming curve from PETRONAS (Azhar *et al.*, 2019). The curve shows a typical "creaming" behaviour – steep rise in resources due to early discovery of big fields, followed by slow incremental resource addition due to gradual decline in field size. In this particular case, however, the remarkably linear creaming curve after 1989 suggests a uniform incremental resource addition since that time. The exploration history can be divided into at least 5 phases (numbered 1 to 5), which are discussed in the text. (B) Creaming curve and key discoveries plotted along with the PSC cycles and major play types P1 to P9 (as listed in Table 1). The PSC cycles are partly based on Ho (1999).

volume. After the key discovery, several other discoveries of similar play type were pursued until the play is exhausted. Other examples of key discoveries are Angsi (1975) and Lawit (1979). An important key discovery at Bunga Orkid (1991) had led to further discoveries in the Malaysia-Vietnam CAA area on the northeastern flank of the basin (Figure 2A), such as Bunga Pakma and Bunga Raya, both discovered in the same year. The curve of an EDP typically flattens as the play type is exhausted and the discovery volumes diminished. The end of an EDP is marked by a discovery with the lowest resource addition (less than 20 MMboe). Some of the key discoveries as well as some volumetrically significant ones are highlighted on the creaming curve in Figure 14B alongside the prevailing PSC cycle.

As of end of 2014, there were 181 oil and gas fields discovered in the Malay Basin (Azhar *et al.*, 2019). This number did not include the oil and gas fields in the JDA area. Based on the information on the MTJA[8] website, to date there have been 90 exploration/appraisal and 292 development wells drilled in the JDA. Table 2 shows the breakdown of these figures according to blocks. These exploration activities have resulted in at least 25 fields according to the map in Figure 5. As mentioned, although the recoverable resources volume for individual fields/discoveries are not available, the total discovered volume per year can be extracted from the data given by Azhar *et al.* (2019). The data are plotted in Figure 15A as the estimated ultimate recovery (EUR) volume discovered each year. Note that each EUR value may represent more than one discovery.

Table 2: Exploration/development well and field statistics for the JDA (source: MTJA website, https://mtja.org/potential.php, accessed 3 October 2020). The fields are shown on the map in Figure 5.

Block	Exploration / Appraisal wells	Development wells	Fields	Field names
Block A-18	40	130	10	Cakerawala, Bulan, Bulan South, Suriya, Bumi, Bumi East, Senja, Samudra, Wira and Samudra North
Block B-17 & C-19	25	134	10	Muda, Tapi, Jengka, Amarit, Mali, Jengka South, Jengka West, Jengka East, Muda South, Charas
B-17-01	15	28	7	Tanjung, Jinda, Andalas, Muda South East, Andalas East, Thanthong, Melati

[8] MTJA website accessed 16 September 2020.

We can see that the discovery history comprises an almost cyclical “saw-tooth” pattern that begins with a sharp spike in resource addition due to an initial one or two key discoveries, followed by a gradual decrease due to smaller discoveries as exploration of the play progresses. The initial spike in resources may be attributed to a new play opener, or due to a renewed effort on a proven pre-existing play, probably spurred by new PSC arrangements with more attractive fiscal incentives. The downtrend in the EUR normally lasts until the expiry of the PSC when exploration work commitments (e.g. seismic acquisition and/or drilling) have been fulfilled by the operators. On top of the cyclical pattern of discoveries, there is also an overprint of a long-term reduction in EUR as field sizes get smaller overall with time.

In Figure 15A we can identify at least 6 saw-tooth-like cycles between 1969 to 2013, each denoted by a downturned curved arrow. Each cycle roughly coincides with the PSC cycle that lasted for about 7 to 10 years. The first such cycle began with the key discoveries in Tapis and Jerneh in 1969. The key discoveries that triggered subsequent cycles are Guntong (discovered in 1977), Larut (1989), Bergading Deep (1997), Cendor (2001) and Sepat Barat Deep (2010). Within each cycle there may be smaller “sub-cycles” due to the discovery of a different play or the same play but in a different block by a different operator. An example is Malong (1983) on the Tenggol Arch, which at that time was a game changer that opened up a new play type, the “basement-drape” play. Another is Bergading Deep (1997) where a deeper target beneath an existing field became a proven play concept especially in the central part of the basin (Figure 11). The 1990s also witnessed the successful exploration for gas in the northern part of the basin, including the JDA and CAA, in the aftermath of the energy crisis of the late 1980s. These are predominantly basin-centre fault-related play discoveries in the JDA area (P3 play type, Table 1). The introduction of new terms under the 1985 PSC was partly responsible for the rejuvenation of exploration in the early 1990s. There was a gap in discoveries in 1995, after the successful campaign by IPC in the CAA area. Bergading Deep had opened up the deeper reservoir play, which had led to similar discoveries later, such as Guling Deep and Sepat Barat Deep (Figure 15A).

The strong influence of the PSC on exploration activities can be seen in Figure 15 which is a plot of the number of discoveries per year since 1968 (Figure 15B). The number of discoveries generally reached a peak during the early part of the cycle (within 1 or 2 years of award), and gradually reduces towards the end of a PSC cycle. It is also interesting to compare the number of discoveries against the number of exploration wells drilled in the same year (Figure 15C). We can see that while the number of exploration wells have steadily increased the number of discoveries has decreased. This supports the suggestion made earlier (see Figure 7) that drilling more wells does not necessarily result in more discoveries.

The following is a summary of the EDP, highlighting the key and major discoveries and the major play types. For each EDP the exploration wells and fields are plotted on separate maps in chronological order (wells in Figure 16, fields/discoveries in Figure 17).

1968 – 1976: Basin-centre anticlinal play discoveries (Figures 16A, 17A)

This first EDP started with a pioneering exploration phase, before the establishment of PETRONAS and the consequent advent of the PSC. In this concession era, almost the entire basin was operated by Esso Production Malaysia Inc. (EPMI). Using regional 2D seismic acquired in 1968, Esso identified large compressional anticlines in the basin axis and subsequently discovered several giant oil and gas fields, which are in production to this day. In terms of play types, the first EDP is characterized by the discovery of these giant anticlinal traps at the basin centre, e.g. Tapis, Jerneh, Bintang, Duyong. It is estimated that P1 type play contributes more than 60% of the total basin resources (Figure 18).

Figure 19 plots the hydrocarbon volumes (EUR) of the major fields according to the designated play type (Table 1) in chronological order. The EUR figures were compiled from various public domain sources listed in Table 3. The earlier discovered fields (during EDP 1) such as Tapis, Jerneh, Seligi, Angsi, and Guntong (solid black circles in Figure 19) have individual ultimate recoverable volume of close to 1 bboe. The first discovery in 1969 was Tapis, with an estimated 760 MMboe recoverable, whereas the largest oil field in the basin, Seligi, with 800 MMboe recoverable was discovered in 1971. Other major oil fields are Seligi, Tapis and Dulang (each with >500 MMboe) while the biggest gas fields are Jerneh, Duyong and Lawit, each with >1.5 tcf of gas.

It is notable that approximately half of the total 14 bboe discovered to date was found during the first EDP (1968 to 1978). In fact, the giant fields whose collective total recoverable resource volume is 4.6 bboe were discovered within a time span of two years, from 1970 to 1971. They include Jerneh, Tapis, Bekok, and Seligi oil fields and the >1 tcf gas fields Bintang, Bujang, Duyong, and Sepat. Subsequent fields like Pulai, Sotong, Angsi and Besar were discovered during the period 1973-1975 and added a further 1.2 bboe of recoverable resources (Figures 6, 14B). The first decade of exploration ended with a leveling of the discovery volumes, contributed mainly by fields such as Palas and Irong in the south-central part of the basin.

1977 – 1989: Basin-centre play creaming (Figures 16B, 17B)

The second EDP started with a rejuvenation of the basin-centre anticlinal play with major discoveries during late 1978 (Tiong, Guntong and Tabu oil fields) and in 1979 (Irong Barat, Lawit and Bergading). The biggest

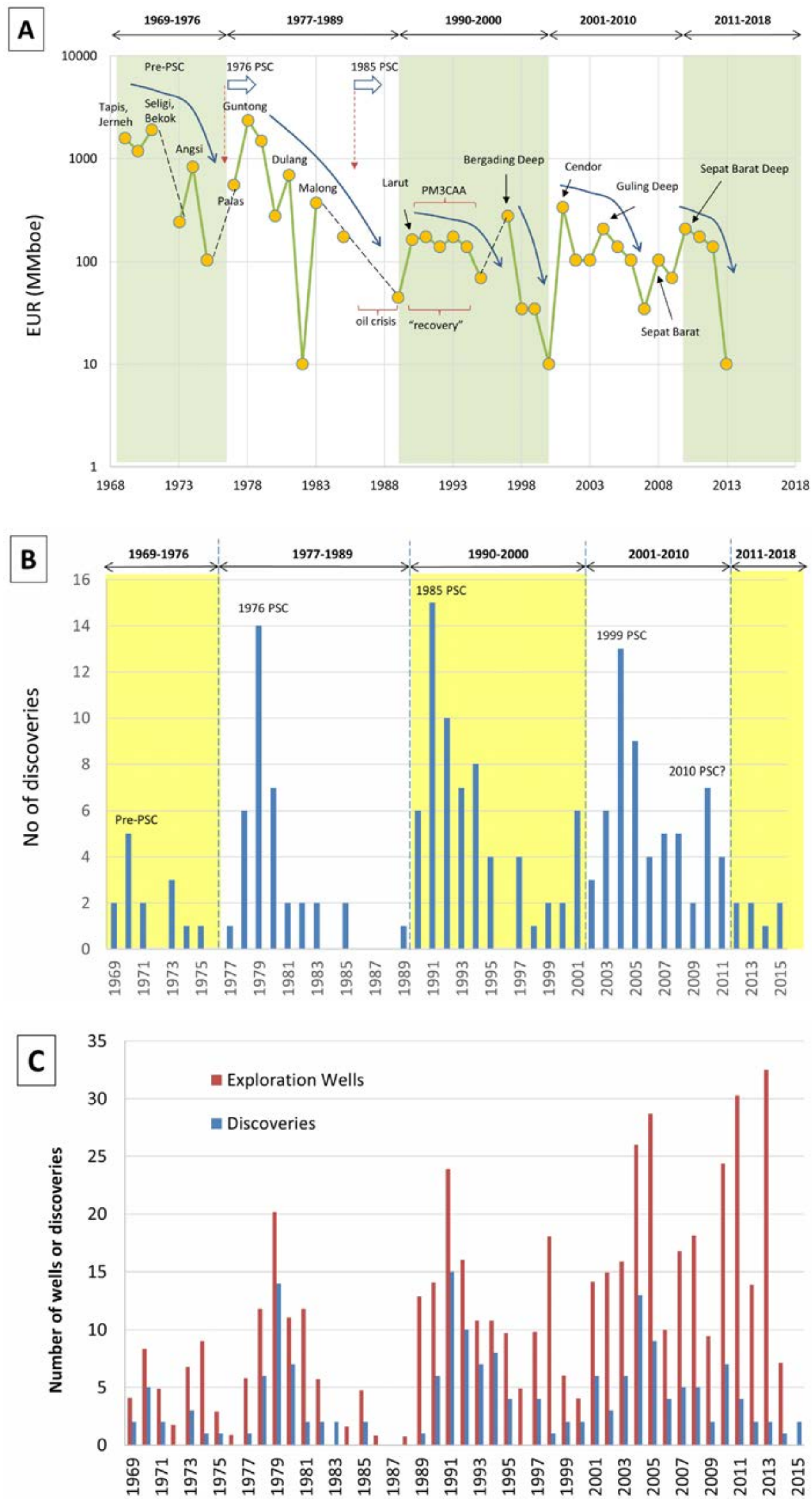

Figure 15: (A) Malay Basin annual volume of discovered hydrocarbon resources, quoted as estimated ultimate recovery (EUR), based on data between 1968 and 2014 published by PETRONAS (Azhar *et al.*, 2019). Vertical axis is in log scale. For reference, vertical dashed lines demarcate the EDPs discussed in the text. (B) Number of discoveries recorded per year from 1969 to 2015. (C) Number of discoveries recorded per year from 1969 to 2015 (as in B), plotted with number of exploration wells drilled per year.

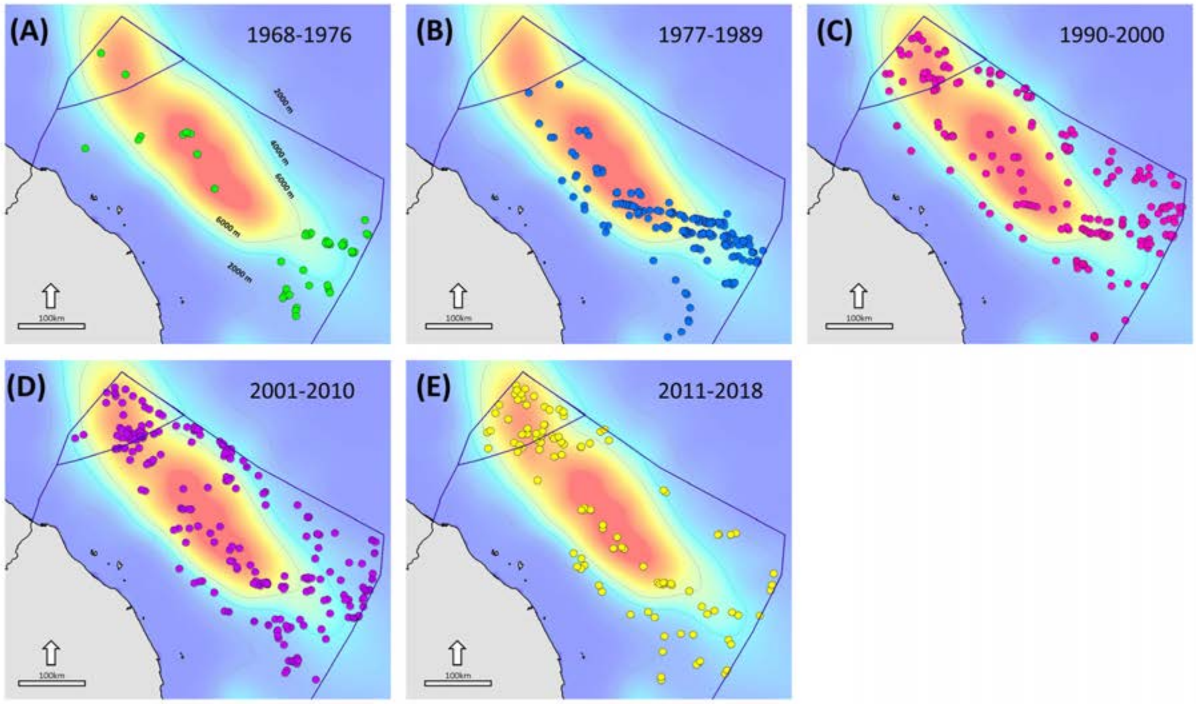

Figure 16: Map of exploration wells drilled during each exploration and discovery phase (EDP) as explained in the text. (A) 1968-1976. (B) 1977-1989. (C) 1990-2000. (D) 2001-2010. (E) 2011-2018. Background map is sediment thickness with contours at 2000, 4000 and 6000 m (see A), based on GlobSed, the global sediment thickness grid of Straume *et al*. (2019).

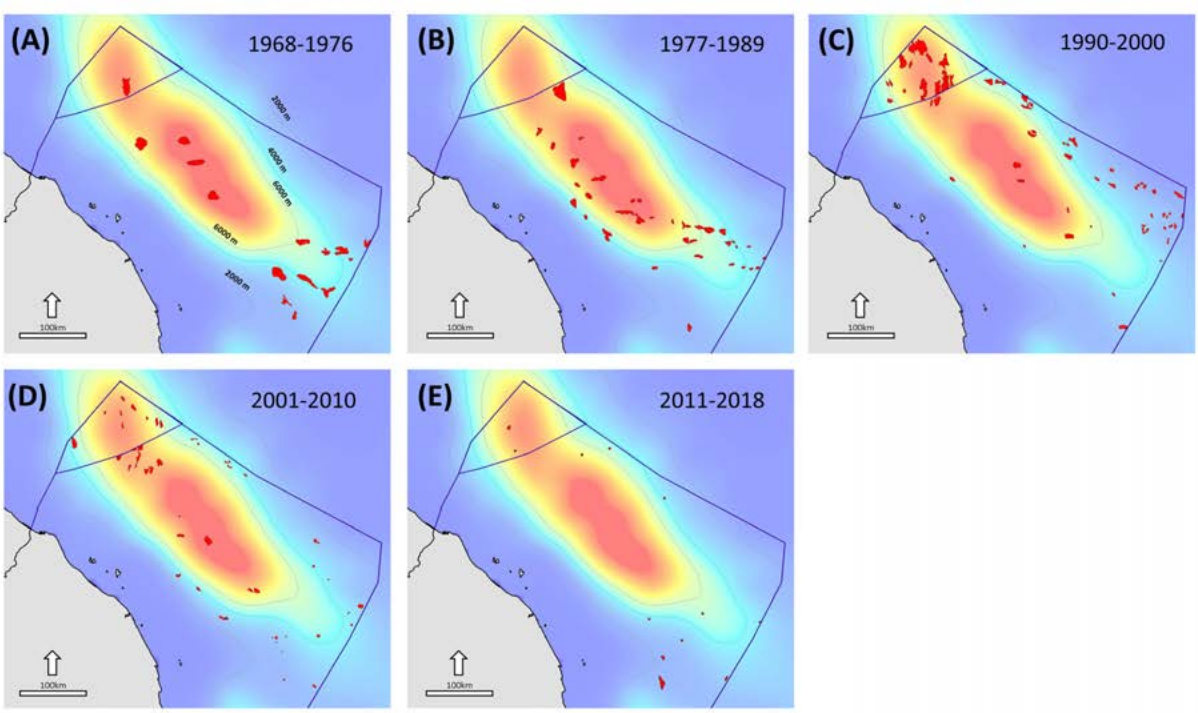

Figure 17: Map of oil and gas fields discovered during each exploration and discovery phase (EDP) as explained in the text. (A) 1968-1976. (B) 1977-1989. (C) 1990-2000. (D) 2001-2010. (E) 2011-2018. Note that the fields get smaller phase after phase. Background map is sediment thickness with contours at 2000, 4000 and 6000 m (see A), based on GlobSed, the global sediment thickness grid of Straume *et al.* (2019).

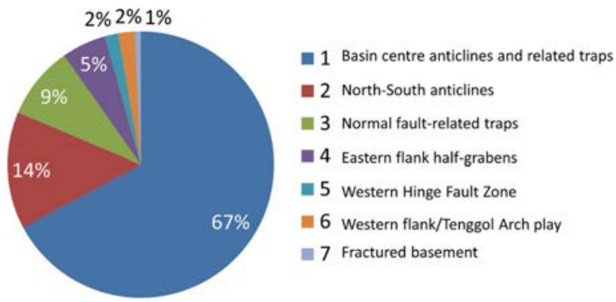

Figure 18: Play types and their proportions in the Malay Basin. In this plot, only the first seven of the nine groups listed in Table 1 are plotted.

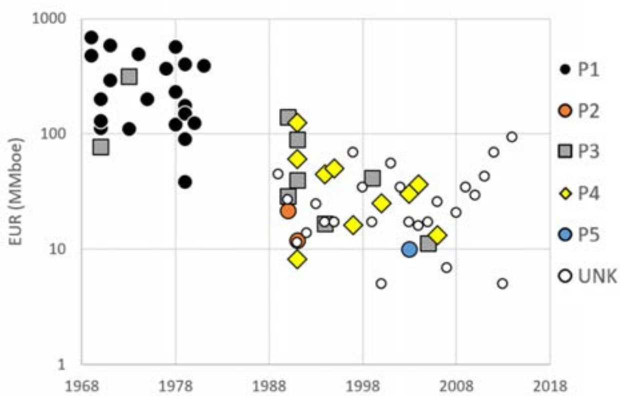

Figure 19: Recoverable resources quoted as estimated ultimate recovery (EUR) for discoveries between 1968 and 2008, based on the available published figures (Table 1), plotted according to the play types described in this paper. As no figures were available for discoveries after 2008, included are average resource volumes for fields discovered between 1989 and 2014, which were derived from the data of Azhar *et al*. (2019) plotted in Figure 6, designated here as "UNK" as their identities are unknown.

oilfield discovered during this phase was Dulang by Esso in 1981 with almost 500 MMboe. During this second phase, exploration was still concentrated mainly within the axial region of the basin, while creaming of the anticlinal play was under way.

The discovery history is also strongly correlated with the PSC cycle, whereby new PSC terms provided the incentive and stimulus for new investments and exploration (Figure 15). During this phase there was a resurgence of exploration activities coincident with, and stimulated by, the new PSCs awarded in 1976 by PETRONAS following its establishment in 1974 under the Petroleum Development Act. It took a few years, however, before the new exploration campaign began to show results (Figure 15B). It was also during this phase that PETRONAS Carigali was established (in 1978) as the exploration arm of the national oil company, which started its operations in the southwestern corner of the basin, the Tenggol Arch and neighbouring Penyu Basin after taking over PSC blocks from Conoco. Malong, Beranang and Resak fields were the most notable discoveries by Carigali during the mid-1980s.

After the significant discoveries at Beranang and Resak, there was a "lull period" in the aftermath of the oil price crash in 1985 and, consequently, the resource addition appears to plateau during the remainder of the 1980s (Figure 14A). Also, at that time, there was a major down-scaling of operations in the industry as a whole, not just in Malaysia but globally. PETRONAS Carigali held on to their exploration blocks on the southwestern part of Malay Basin and the Penyu Basin but did not carry out much exploration due to the downturn. By the end of 1987, most of the large compressional anticlinal traps (P1 play) in the basin centre had been tested, and all the giant fields had been found. As the number of remaining compressional anticlines was decreasing, exploration efforts gradually shifted onto the western margin plays on the basin flanks, especially in the Western Hinge Fault Zone, Tenggol Arch and adjacent Penyu Basin. Overall, the incremental resource addition during this phase had been modest.

On the Tenggol Arch, following the Malong discovery in 1984, wells were deliberately targeting basement drape features as Malong look-alikes, but most were unsuccessful. Many wells, however, were drilled into the pre-Tertiary basement and provided further insight into the nature of the pre-Tertiary basement in this region (Madon *et al*., 2020). Since the Tenggol Arch is covered in most places by less than 2.5 km of sediment the presence of a generative source-rock within the Tertiary section above the pre-Tertiary basement is considered unlikely. This contrasts with the NE ramp margin where several small Tertiary half-grabens on the basin flanks have proven to be effective kitchens, such as Bunga Raya graben (Figure 13).

Looking carefully at the creaming curve, during the first two EDPs (1968 to 1989) there were two "creaming" stages of almost equal magnitude in time and volume. The first (1968-1976) was when the major creaming phase took place, with the discovery of the giant fields mentioned above. The second EDP (1977-1989) was almost a repetition of the first, which followed right after the introduction of the 1976 PSC. This demonstrates the importance of regulatory and fiscal stimulus to exploration (i.e. attractive fiscal terms in production-sharing contracts), which are as important as exploration technology and scientific know-how.

1990 – 2000: Basin rejuvenation (Figures 16C, 16D, 17C, 17D)

Recovery from the industry downturn in the mid-1980s took over a decade, in spite of the introduction of new PSCs in 1985. Starting in 1990, however, there was a period of rejuvenation of exploration and discoveries. This was mainly due to the successful testing of new plays on the northeastern flank of the basin in the Commercial Agreement Area (CAA) between Malaysia and Vietnam

Table 3: Oil and gas fields and discoveries in the Malay Basin by year (1969-2015). Data from various sources, mainly PETRONAS (1999, 2019), AAPG Bulletin (1968-1989) and IHS Energy. Annual discovered resource volumes quoted in estimated ultimate recoverable resources (EUR) were derived from Azhar *et al.* (2019). n/a – not available.

Year	No. of discoveries	Fields and discoveries	EUR (MMboe)
1969	2	Tapis, Jerneh	1580
1970	5	Bintang, Sepat, Bujang, Duyong, Belumut	1179
1971	2	Seligi, Bekok	1896
1973	3	Anding, Sotong, Pulai	241
1974	1	Angsi	828
1975	1	Besar	103
1977	1	Palas	552
1978	6	Irong, Tiong, Guntong, Ledang, Tabu, Berantai	2345
1979	14	Ophir, Telok, Irong Barat, Lawit, Kapal, Serok, Jerneh Barat, Bergading, Tujoh, Inas, Damar, Kepong, Bedong, Noring	1483
1980	7	Pendera, Tangga, Tinggi, Semangkok, Semangkok Timur, Ledang Barat, Peta	276
1981	2	Dulang, Belanga	690
1982	2	Resak, Beranang	10
1983	2	Meranti, Malong	369
1985	2	Tangga Barat, Payung	172
1989	1	Tembikai	44
1990	6	Gajah, Laba Barat, Melor, South Raya, Larut, East Raya	162
1991	15	North Lukut, Bundi, Kuda, Abu, Ketumbar, Lawang, Bunga Orkid, Delah, Ular, West Belumut, Abu Kecil, Bunga Pakma, Bundi South, Bunga Raya, Chermingat	172
1992	10	Serudon, Rabung, Pantai, Mesah, Piatu, Bubu, Lerek, Cahaya, Peta Kiri, Penara	138
1993	7	Laho, Larut Liku, North Raya, Guling, Telok Timur, Duyong Timur, Diwangsa	172
1994	8	Yong, East Belumut, Langat, Korbu, Kaca, East Bunga Orkid, Bunga Kekwa, Northwest Pinang	138
1995	4	Bindu, Bertam, Cengal, Bergading Deep	69
1997	4	West Bunga Kekwa, Bunga Seroja, Northwest Bunga Raya, Ipoh	276
1998	1	North Bunga Pakma	34
1999	2	East Piatu, Permatang	34
2000	2	Bunga Teratai, Bunga Dahlia	10
2001	6	Cendor, Bunga Raya East, Chenang, Enggor, Enggor Timur, North Bunga Raya	335
2002	3	Bunga Melati, Bunga Raya West, Desaru	103
2003	6	Beranang NW, South Angsi, North Bunga Orkid, Sepat Deep, Bunga Kamelia, Bunga Tulip	103
2004	13	Kenarong North, Kenarong, Api-api, Pertang, Suriya Selatan, Bunga Zetung, Semangkok Timur Deep, Senjuang, Banang, Anding Utara, Guling Deep, West Bunga Orkid, Bunga Anggerik	207
2005	8	Lukut, Kuning, Bumi South, Murai, Anding Barat Laut, Bunga Kesumba, Puteri, Naga Kecil, Anding Basement	138
2006	4	Bunga Matahari, Bunga Dahlia Channel, Padang, Anding Tengah	103
2007	5	Bunga Daisi, Bunga Seri Pagi, Sentang, Jebat, Naga Dalam	34
2008	5	Abu SW Upthrown, Kecubung, Aji-aji, Telok Shallow, Sepat Barat	103
2009	2	Irama, Ledang Barat Deep	69
2010	7	Bunga Bakawali, Bunga Tanjung Merah, Melawati, Sepat Barat Deep, Ledang Tengah Deep, Bunga Tanjung, Gelama	207
2011	4	Sepat Barat Deep-2, Naga Emas, Berantai East, Inas-7	172
2012	2	Duyong Shallow, Rajah Shallow	138
2013	1	Perias	10
2014	1	Bunga Lantana	n/a
2015	2	Gansar, Bunga Kamunju	n/a

(Figure 1). The half-graben plays in the northeastern corner of the basin included, e.g., Bunga Orkid, Bunga Kekwa, Bunga Pakma and Bunga Raya.

In the northeastern ramp margin covered by the Esso exploration blocks PM5, PM8 and PM9 at the time, exploration resulted in the discovery of fields such as Larut, Mesah, Lerek, and Piatu. There were also discoveries in the central/northern part of the basin such as Bunga Dahlia, Bunga Kamelia, Bunga Tulip and Bunga Melati. Compared to the larger anticlinal play type (P1) these are essentially smaller accumulations, occurring especially towards the northern part of the basin where the N-S structural trend is more akin to that of the Pattani basin and the Gulf of Thailand (Figure 4). It is estimated that these new play discoveries on the basin flanks added about 1.5 bboe to the recoverable resources (Figure 14B).

It is worth to highlight that, several years prior, during the economic downturn and operational scale-down, Esso had carried out a major regional study on the northeastern flank, covering the entire basin but focusing specifically on its PM5 and PM8 blocks. That study, which came to be known as the "EPIC" study (1994), had certainly provided a new impetus for exploration and discovery during this phase. A successful drilling campaign launched after the study that lasted until around 1997 contributed an additional ~1 bboe of recoverable resources.

At the same time, exploration on the Tenggol Arch continued during this EDP. The exploration model at that time envisaged that the structures on Tenggol Arch could be filled by hydrocarbons that migrated up the Tenggol Fault by long-distance migration over 30-60 km from the source rock kitchen in Malay Basin. Up to 1995, four more structures on the Tenggol Arch were drilled: Kempas, Jelutong, Keledang, and Bertam. Only Bertam-1 well, drilled in 1995, found hydrocarbons. The Bertam discovery is probably located near a local generative kitchen, which could be either east of the Tenggol Fault or to the south or southwest in one of the half-grabens in Penyu/West Natuna Basin.

During the late 1990s, most of the discoveries in the Malay Basin were in the central basin gas play to the north, including the Malaysia-Thai Joint Development Area (JDA). A successful appraisal campaign in this area started with the discovery of Gajah gas field in 1990 (see location in Figure 5 and cross-section through the field in Figure 13). Most of the significant finds thereafter, during the latter part of the nineties, from around 1996 were in the JDA, with gas fields like Bumi, Jengka, Suriya, Muda and Samudra. Samudra-1 well was the last discovery that had recoverable resources greater than 100 MMboe. These discoveries are essentially in the basin centre, but within the north-trending part of the basin straddling the JDA and the Thai sector of the basin. Hence, the structures are more comparable to those in the Pattani Basin (Figure 5).

As exploration activities moved into the flank areas during the mid-1990s, starting on the west side and then to the east, it was realized that oil could be trapped in fault-assisted traps, away from the basin centre anticlines where the giant accumulations occur. These traps are smaller than the large anticlines at the basin centre. Nevertheless, a boost in gas resource addition had enabled PETRONAS to secure the much-needed natural gas supply to the Peninsular Malaysia Gas Utilization Project, which was launched in 1984 but had anticipated the shortage of gas supply from the Malay Basin.

2001 – 2010: Marginal play expansion (Figures 16E, 17E)

During this EDP, discovery volumes remained small even though the number of wells drill each year was high (Figure 7). This phase is characterized by marginal resource addition achieved through discovery of "small fields" (defined as fields with <30 MMboe in place) by near-field exploration or satellite-field appraisals. By this time, even the discoveries in the JDA were becoming smaller and smaller.

To stimulate exploration activities, PETRONAS introduced improved fiscal terms in the new PSCs. As a result, some companies were able to test some of the more technically and operationally challenging plays, such as the deeper reservoirs beneath known accumulations, e.g., Tangga, Bujang, Inas, and Guling. This effort, which began in 1996, resulted in the discovery at several deep wells drilled during the first half of this EDP, such as Inas Deep-1 and Guling Deep-1 (Hamdan *et al.*, 2006). Other play types pursued during this phase included stratigraphic channel plays such as Besar Channel-1 (2004) and Bunga Dahlia Channel-1 (2006), which were relatively shallow wells at about 1500 and 2620 m total depth, respectively. It was immediately recognized that the ability to characterize channel features in seismic data tend to deteriorate with depth as the seismic resolution decreases. At the height of "channel chasing" campaign, PETRONAS had collected a large database of 3D merged seismic to help identify more channel features (Rosemawati, 2008).

It was also during this phase that exploration for fractured basement reservoirs was at its peak, culminating in the appraisal of Anding basement structure during 2004 to 2008 (Siti Zainab *et al.*, 2008; Mohd Kadir, 2010). A special task force on "Fractured Basement" was established, carrying out activities that included field trips to look at fractured granites in Peninsular Malaysia and Vietnam (Mohd Kadir & Hamdan, 2009), even though the pre-Tertiary basement reservoir at Anding is made up of metamorphic rocks (schists and phyllites). Efforts in fractured basement exploration, however, has not met the expectations, while development of the Anding basement reservoir is still on hold.

2011 – 2018: Residual mop-up (Figures 16F, 17F)

During the past decade, the number of discoveries was more than 80, which is quite significant. However, the incremental addition to the resources volume has been dismal, proving that the basin has indeed been fully explored. This EDP may be regarded as the mopping up of "residual" hydrocarbons that remain in relatively small accumulations (<10 MMboe). Besides the regular play types, however, new plays were pursued, which included the High-Pressure/High-Temperature (HPHT) plays, overpressured plays, and tight sands in the synrift section of the stratigraphy.

The testing of the HPHT play opened up a new potential in the overpressure zoned in the north-central part of the basin, where major gas-rich compressional anticlinal discoveries of the 1960s are located, such as Jerneh, Lawit, Bintang, Damar, Noring, Guling and Tujoh. During this EDP, testing of deep reservoirs and tight sands were carried out, but not without the technological and operational challenges. For example, the 2013 drilling of well Duyong Deep-1, said to be the first "Ultra HPHT" well, targeted Lower Oligocene Group M, and reached a final well depth of 4350 m subsea. Gas bearing sandstones were encountered, but the reservoir quality was poor (porosities 3-8%, permeabilities 0.0025 mD). At those reservoir depths, the well recorded a temperature of 253 °C and a pressure of 96 MPa (13900 psi) (Mohamad *et al.*, 2014). Similarly, following the success of Sepat Barat-1 in 2009, the well Sepat Barat Deep-2 drilled in 2014 tested overpressured reservoirs in Group F and H to reach a final depth of 2768 m. It penetrated more than 1000 m of overpressured zone and found 69 m of gross hydrocarbon-bearing reservoir. At a depth of 1748 m the pressure was 54 MPa (7826 psi) and the maximum temperature was 171°C (Osman *et al.*, 2012). Obviously, these challenges would need to be overcome in the future if drilling deeper targets is to continue. Upon discovering hydrocarbons in Group M sands at Duyong Deep-1, however, PETRONAS Carigali proceeded to drill the up-dip equivalents of Group M reservoirs on the Tenggol Arch with well Gansar-1 in 2014, and subsequently an appraisal well Gansar-2 in 2017 (Md Rosly *et al.*, 2019). Despite the presence of hydrocarbons in these sands, the reservoir quality was deemed to be low. Further research on the controls on reservoir quality in Group M sands may help in identifying the remaining prospective targets.

The latest discovery on the Tenggol Arch was in 2012 at Tembakau-1, about 32 km west of Malong. Similarly, Tembakau oil seem to be sourced from a nearby kitchen. The other wells drilled prior to Tembakau were dry, suggesting that the long-distance migration model previously assumed did not work. Recent studies have also investigated the potential of sedimentary rocks in the pre-Tertiary "basement". These rocks are not basement in the traditional sense but older sedimentary rocks of possibly Mesozoic and Paleozoic age similar to, and probably a continuation of, those rocks outcropping on land in Peninsular Malaysia (Madon *et al.*, 2020). Although they were referred to as "pre-Oligocene rifts" (M. Hafiz *et al.*, 2019, Iyer *et al.*, 2019), a major truncational unconformity (base-Tertiary unconformity) indicates that they belong to an earlier tectonic cycle that is likely to be pre-Tertiary (Mesozoic/Paleozoic). Further work is required to develop this and other new play concepts to sustain exploration and resources addition beyond 2020.

FIELD SIZE DISTRIBUTION

In the PETRONAS book of 1999, Wong (1999) reported that the total discovered hydrocarbon volumes in the Malay Basin were 12.5 bboe in-place (equivalent to EUR of 4.3 bboe) and 57.1 tcf of gas in-place (=EUR of 39.4 tcf). These were contained in 53 oil fields and 28 gas fields, and out of these, 14 are giant oil fields and 6 giant gas fields (based on a threshold of 100 MMboe and 1 tcf, respectively). In the recent update 20 years later (Azhar *et al.,* 2019), the number of oil and gas fields has risen to 181 as of end of 2014; 82 are oil fields and 99 gas fields. Of these, there are 47 producing oil fields and 26 producing gas fields.

Official figures for field size are rarely published. Table 4 is a list of resource figures of some of the major oil and gas fields compiled from the literature, mainly from the PETRONAS book (1999). Together with the data in Table 3, it is possible to analyse the field size population as it evolved over the course of the basin exploration history. The field size population can be characterized as having a lognormal distribution, as shown in Figure 20A, where field size population is heavily skewed towards smaller fields. As expected, there are more small fields than there are big ones; and as exploration progresses the chance of finding large fields diminishes. A characteristic feature of lognormality is that a lognormal population will plot as a straight line when plotted on a log-probability chart, as shown in Figure 20B. From this plot, the P10, P50, and P90 values can be easily determined. A field size at P10 value represents the value at which there is a 10% probability that a given field has a size greater or equal to that value, while a P90 value represents the value at which there is a 90% probability that the field size is greater or equal to that value. P50 is when there is equal chance that the field size is below or above that value, and is the median value of the population. In practice, the P10 value is usually considered as the "high case" and P90 as the "low case" resources. The P50 value is sometimes used as the "most likely" value of a resource estimate, in place of the arithmetic mean (expected) resource value which is obtained from the calculation of the statistical parameters. In Figure 20B, the P50 value or estimated ultimate recovery (EUR) is 82.7 MMboe which, due to lognormality, is lower than the arithmetic mean (177 MMboe) (Table 5).

When field sizes are plotted according to individual play types, it is possible to characterize the field size population for each play type. Unfortunately, with the available data, only 3 of the 7 play types have adequate datapoints to be plotted; they are P1, P3 and P4 (Figure 21). The statistical parameters for the individual field size population are listed in Table 5. It is observed that the paramaters, in particular the median and mean field sizes of the different play types,

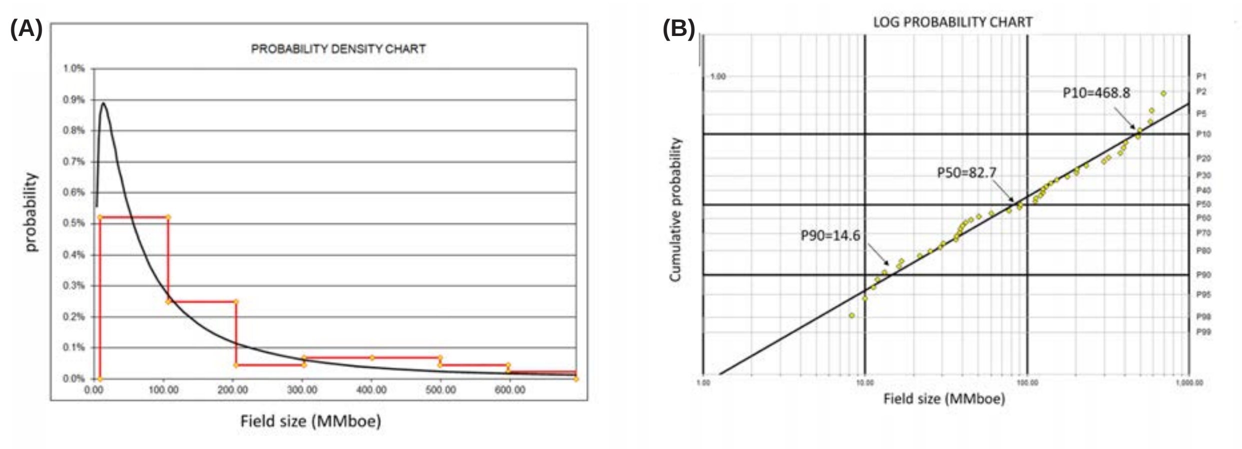

Figure 20: (A) Probability density plot of field size (recoverable resource volume) for Malay Basin, given in class intervals of 100 MMboe. As expected, the distribution is highly skewed such that there are more small fields than there are big ones, which is characteristic of a lognormal distribution, as outlined by the black curve. (B) Log-probability plot of field sizes (EUR volume in MMboe) of Malay Basin fields (as tabulated in Table 1). In this plot, x-axis is resources in log scale and y-axis is cumulative probability from P100 to P0. A lognormal population of field sizes would plot along a straight line as shown by the best-fit line through the yellow points. From the straight line, the values for P10 (high case), P50 (median case) and P90 (low case) can be obtained, as indicated. The mean resource value is 176.9 MMboe.

Table 4: Published estimated ultimate recoverable resources (EUR) figures for Malay Basin. STOIIP – Stock Tank Oil Initially In Place, GIIP – Gas Initially In Place.

Year of discovery	Field name	EUR (MMboe)	Source	Remarks
1969	Tapis	484	PETRONAS (1999)	
1969	Jerneh	695	PETRONAS (1999)	Equiv. 4.9 tcf
1970	Duyong	131	PETRONAS (1999)	Equiv. 0.93 tcf
1971	Seligi	589	PETRONAS (1999)	
1971	Bekok	296	PETRONAS (1999)	
1973	Pulai	112	PETRONAS (1999)	
1974	Angsi	497	Tan (2019)	Estimated from STOIIP 774MMboe+GIIP 1.33 tcf
1977	Palas	115	PETRONAS (1999)	
1978	Tiong/Kepong	232	PETRONAS (1999)	
1978	Tabu	121	PETRONAS (1999)	
1978	Guntong	573	PETRONAS (1999)	
1979	Irong Barat	152	PETRONAS (1999)	
1979	Lawit	298	PETRONAS (1999)	Equiv. 2.1 tcf
1980	Tinggi	125	PETRONAS (1999)	
1981	Dulang	274	Tan (2019)	

Table 5: Statistics of the field size distribution for Malay Basin. Recoverable resource volumes in MMboe.

Statistics	All fields	P1 play	P3 play	P4 play
P10	468.8	695.4	271.8	107.6
P50	82.7	191.6	52.1	31.1
P90	14.6	52.8	9.99	8.99
Mean	176.9	294.6	104.2	46.4

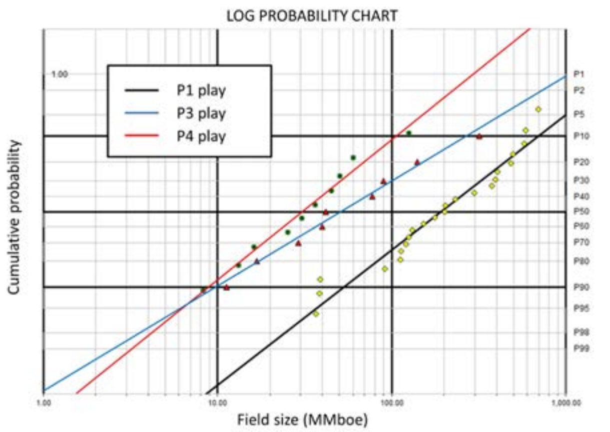

Figure 21: Log probability plot for three play types, P1, P3 and P4 based on the data in Table 1. Only three plays have more than 2 data points to be able to plot on the chart. Values of P90, P50, P10 and mean resources for the play types are tabulated in Table 3.

decrease from P1 to P3 to P4. Hence, by the third EDP in the early 1990s the median field size had been reduced to 30 MMboe. This effect is observed in the creaming curve (Figure 6) where, as expected for a fully explored basin, the median field size decreased over time, as the field-size population shifts from right to left on the log-probability plot. This shift is also related to the exploration history, whereby the large discoveries of P1 type were made during the early phase of the basin history (EDP 1 and 2) whereas the exploration and discoveries of P3 and P4 plays did not take place until 1990 at the beginning of EDP 3 (see Figure 14B).

Hence, the available data show that over the thirty-year period (1968-1998) during which play types P1 to P4 were explored the median field size (P50) had diminished exponentially over time, from 192 through 52 to 31 MMboe (Table 5). This suggests that the median field size in the future, assuming the same plays are being explored, is likely to be much lower than 30 MMboe. As the data from Figure 6 indicate, the 128 fields discovered between 1989 and 2014 have an average size of less than 24 MMboe. This demonstrates that the average field discovery size in the future will only get smaller, unless new plays are explored.

COMPARISON WITH OTHER BASINS

Although the creaming curve in Figure 6 suggests that the Malay Basin may have attained "maturity" (i.e., almost fully explored), the constant but slow increase in incremental resource addition since the 1990s seem to suggest that there is still significant potential. The question is should oil companies continue the "mopping up" by drilling for the small accumulations or should they find and test new plays? Certainly, if the present trend continues, there will be a time when drilling more wells will not result in more discoveries or more resource addition. More importantly, what plans are being put in place by PETRONAS as a long long-term strategy for the exploration and production industry.

"Basin maturity" (not to be confused with source rock maturity) is a subjective exploration parameter. Can it be measured more objectively? Table 6 shows basin parameters that may be used as indicators of the exploration intensity of petroleum basins. Well density is a possible criterion to differentiate between frontier and well-explored basins, for the simple reason that more wells are drilled as exploration progresses. So, for example, the Central Graben of the North Sea with the lowest area in square kilometers per well may be considered to be more highly explored than say the Deepwater Gulf of Mexico basin or any basin in Malaysia (Table 6). Conversely, the lower the number (area per well) the more intensely explored is the basin. We can also see from Table 6 that Malay Basin is more explored than Sarawak and Sabah basins, while Baram Delta by itself is the most explored basin in Malaysia.

The exploration intensity parameter, shown in Table 6, may be used to compare the exploration levels of Malaysian basins with global basins by the "exploration intensity index" (calculated as the area per well drilled) against basin size (Figure 22). Based on the data from IHS Energy in 2014, the Malay Basin shows an exploration intensity level that is intermediate relative to well-known highly explored basins

Table 6: Comparison of "exploration intensity index" (calculated as the area per well drilled, 4th column) of different basins. Lower numbers indicate higher exploration intensity index. Note*: Wells include exploration and development wells. These figures were based on IHS data in 2014. Central Graben is in North Sea. GOM is Gulf of Mexico.

Basin	Area (sq. km)	No. of Wells*	Area per well
Central Graben	59,333	3217	18.4
Deepwater GOM	436,667	3504	124.6
Malay (incl. Thai and Vietnam portions)	128,240	3038	42.2
Malay (Malaysia portion only)	83,000	1791	71.6
Baram	73,775 (20,999)	2347	31.4 (8.9)
Sarawak	378,190	840	450
Sabah	47,302	475	99.6

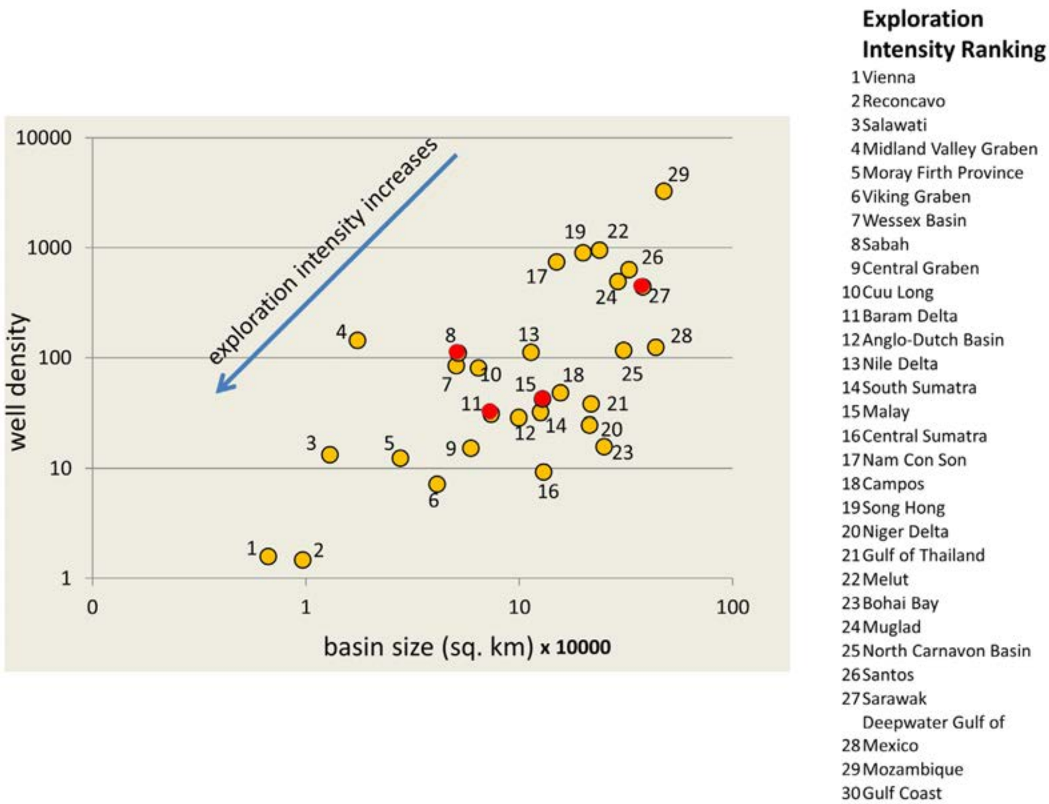

Figure 22: Log-log plot of well density vs basin size for 30 worldwide basins, including Malaysian basins. Based on 2014 data from IHS. The calculated "Exploration Intensity Index" = area per well vs basin size. Note: Malay Basin is still moderately explored compared to other known highly explored basins such as Viking Graben.

of the world, e.g. Vienna, Reconcavo, Salawati and the North Sea basins. Sarawak Basin seems to have significant remaining potential based on this ranking, and the creaming curve for the Sarawak Basin (Azhar *et al.*, 2019) supports this interpretation.

It should be borne in mind that "basin maturity" defined in terms of well intensity may be an oversimplification. Exploration intensity (if measured by number of wells per unit area) is also dependent on the geological complexity of a given basin. A geologically simple basin may have a few very large structures and would need a small number of wells (=less "intense" exploration) before being fully explored as compared to a geologically and structurally complex basin with rapid sedimentary facies changes and structurally controlled sub-basins. Perhaps, for this reason, the Malay Basin and similar basins in SE Asia may still have significant remaining potential.

REMAINING POTENTIAL

It is important for oil companies and investors to have a good idea of the remaining potential of a basin. There had been several attempts to assess the total undiscovered resources in Malay Basin (Robinson, 1984, 1985; USGS, 2000; Bishop, 2002). Twenty-five years ago, Robinson (1985) from the USGS[9] published an estimate of the mean undiscovered or "yet to find" (YTF) resources for "West Malaysia", which was essentially the Malay Basin. He concluded that as of July 1982 the undiscovered resources were 2 bboe oil and 17 tcf gas (Table 6). These amounted to a total undiscovered volume of oil equivalent of approximately 5 bboe, assuming USGS conversion rate of 6000 cubic ft of gas to 1 boe. Based on the creaming curve in Figure 6, by 1985 approximately 11.7 bboe had been discovered in the basin. Since 1985, approximately 3.1 bboe have been added to the cumulative resources of 14.8 bboe by the end of 2014. The latest figures are not available but if we project the resource addition to 2020 using the discovery rate of 120 MMboe per year, the cumulative resource at 2020 would be 15.5 bboe. It appears that Robinson's prediction was not too far off the mark.

The USGS had subsequently made several revisions to the estimation (Table 5). It is as expected that numbers may

[9] United States Geological Survey

Table 7: Estimates of undiscovered recoverable hydrocarbons by USGS for Malay Basin based on different year of assessments. For comparison, the estimates for Pattani Trough and Song Hong Basin for 2012 are included. Sources: Robinson (1985), Bishop (2002), USGS (2010), Schenk (2012), USGS (2019). n.a.= not available.

Basin	Year of assessment	Oil (1000xMMbbl)	Gas (tcf)	Total undiscovered HC (MMboe)
Malay Basin	1985	1.98	17.2	4.84
Malay Basin	2000	1.23	27.5	6.32
Malay Basin	2010	0.64	9.76	2.27
Malay Basin	2012	0.66	12.1	2.68
Malay Basin (this study)	2020	n.a.	n.a.	2.00
Thai Basin/Pattani Trough	2012	1.21	14.6	3.64
Song Hong Basin	2012	0.61	12.3	2.65

change over time as estimation parameters change when new information becomes available, although the details of the calculations are not apparent from the reports. The total undiscovered volume may also decrease with time as more discoveries are made. It is notable that there was a downward revision in 2010. Based on the latest estimates in 2012, it was predicted that approximately 2.7 bboe was left to be discovered. At the end of 2012, the cumulative discovered resources already stood at 14.7 bboe (Figure 6) and up to 2014, 0.1 bboe had been added from new discoveries. If we project to 2020 at the same rate of discovery (120MMboe/year) there is an estimated ~2 bboe yet to be discovered in the basin.

It is useful to compare the resource estimation for Malay Basin with those for Pattani Trough (Thailand) and Song Hong Basin (also known as Pearl River Mouth Basin or Yinggehei Basin) since they are of similar size and tectonic setting (e.g., Clift & Sun, 2006). As shown in Table 7, the numbers are comparable, i.e. in the same order of magnitude, especially between Malay and Song Hong basins. In terms of exploration maturity, however, the Song Hong and Thai basins may have not reached the same level as Malay Basin (Figure 22). It is important to note these are estimates and their reliability depends on the geological data and information available. With the wealth of data collected over the five decades, PETRONAS is in a good position to carry out its own assessment more rigorously and accurately, as the numbers are critical from the strategic perspective of the national oil company in charting the industry forward.

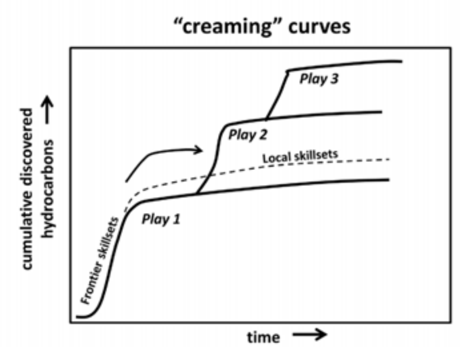

Figure 23: Hypothetical creaming curves, redrawn from Tobias (2018), which resemble the Malay Basin curve (Figure 14A). Different phases of the creaming curve require slightly different skillsets. During the early phase of creaming when resource addition is rising, "frontier skillsets" are used to discover the large accumulations. When the resource addition reaches a plateau, however, a different skillset is required which is much more rigorous, scientific and technology-intensive, termed "local skillsets" by Tobias (2018). Local skillsets would require certain amount "residence time" in order for the practitioner to develop a thorough and deep basin knowledge, i.e. from "frontier knowledge" to "localised knowledge". In my opinion, that localised knowledge is lacking for the Malay Basin.

CONCLUDING REMARKS

In summary, exploration in the Malay Basin since 1968 has resulted in the discovery of over 181 oil and gas accumulations that contribute in total more than 14.8 bboe of recoverable resources to the national petroleum resources to date. More than half of the discovered resources (8.7 bboe) were discovered during the first decade of exploration (1968-1977) through the giant oil and gas fields located in the basin centre. Historical exploration data indicate the following key points regarding the status of petroleum exploration in the Malay Basin:

- Creaming curve shows that the size (volume) of discovery is diminishing and since the mid-1980s the incremental resource addition and the rate of return per well have been very relatively low. This trend will continue if no new plays are successfully tested.
- Based on the most recent estimates, there could be approximately 2 bboe of hydrocarbons yet to be discovered in the Malay Basin. At the current rate of discovery and the low expected volumes of hydrocarbons, the industry would be spending more exploration dollars per barrel and in the long run this would increase the cost of exploration and reduce the rate of return on investment.

- Exploration in the basin can only be sustained with new play concepts developed and tested successfully, e.g., subtle traps (Zhou, 2019). Since the "easy hydrocarbons" have been creamed off, more attention to detailed scientific knowledge and technology applications is required to sustain the resource addition. New technologies, coupled with "local skill-sets" will be important enablers towards maximizing the remaining recoverable hydrocarbons (Figure 23).

During the five decades of exploration in the basin, a voluminous amount of seismic (2D and 3D) data had been acquired and, along with over 2000 exploration and development wells, it is important that these data are fully utilized to gain a thorough understanding of the basin geology and petroleum systems. With these data, it is critical to identify new plays and build a basin-scale hydrocarbon charge model that could improve the assessment of the remaining potential.

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CONFLICT OF INTEREST

The author has no conflicts of interest to declare that are relevant to the content of this article.

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