MICROBUBBLE DRILLING FLUID (APHRON): NEW TECHNOLOGY FOR DRILLING IN DEPLETED RESERVOIRS

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Summary

Lost circulation is a severe problem in drilling processes, especially in depleted zones. Microbubble (aphron) drilling fluid is a novel technology that possesses excellent advantages compared with other lost circulation prevention methods. The three-layer structure of microbubbles not only lessens the density of fluids, but also acts as stable bridging materials by which cracks in depleted zones could be sealed effectively. These features result in successfully reducing lost circulation. Though possessing an excellent potential for preventing lost circulation, this kind of fluid has not yet been studied in Vietnam. This paper will briefly introduce the topic of microbubble drilling fluid, including the structure and composition of aphron, how this fluid works and recent developments of this technique in drilling oil fields around the world.

Key words: *Aphron, microbubble drilling fluid.*

1. Introduction

Lost circulation happens due to the difference between the hydrostatic pressure of the drilling fluid and the reservoir pressure, leading to fluid penetration into cracks. In the case of operating processes, if no solution is found for this problem, drilling processes must be suspended, resulting in considerable economic damage.

An alternative, which is recently developed and is widespread, is the underbalanced drilling technique. This method, however, requires extremely expensive equipment and special protective measures. Amongst other special drilling solutions developed for operating in depleted zones, one novel drilling solution, using a particular drilling fluid, has attracted the attention of drilling specialists and companies.

The fluid, known as "aphron-based drilling fluid", is water-based of low density and reduced cost. Aphron drilling fluid can be prepared by mixing surfactants, viscosity polymers and stabilisers to form aphron with a particular structure that can withstand high pressures without being destroyed.

An aphron was first found by Sebba in 1984 [1] and was described in more detail in his next report in 1987 [2].

2. Structure of aphrons

The structure of an aphron is illustrated in Fig.1. Unlike conventional air bubbles which are covered by a single thin layer of surfactants, an aphron has a more complex structure. The air core of aphrons is enveloped by a substantially stable tri-layer. This tri-layer consists of an inner surfactant film, covered by a viscous water shell, and the outer layer is a bi-layer of surfactants. This tri-layer structure could not only greatly enhance the stability of aphrons, but also make aphrons hydrophilic. The hydrophilic boundary of aphrons makes the micro bubbles compatible with bulk water solution and lowers the attractive forces between them.

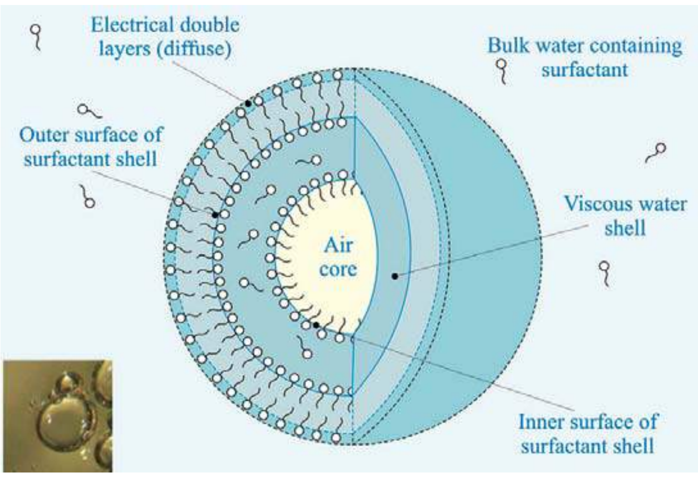
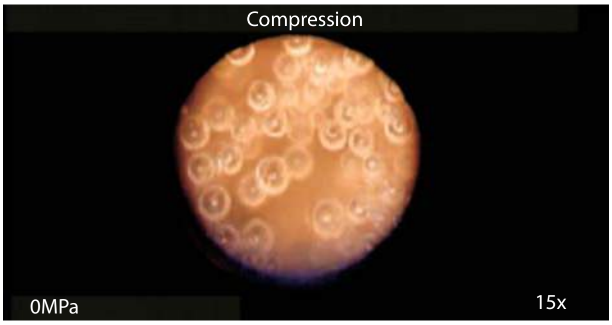


Fig.1. *Structure of an aphron*



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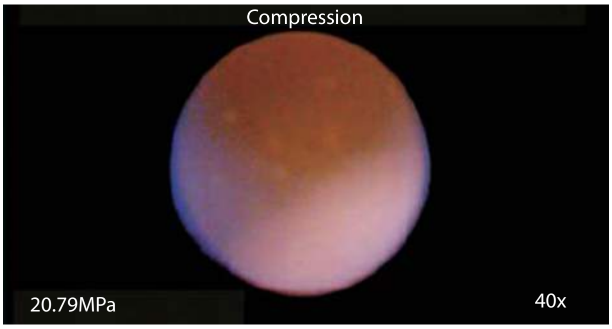

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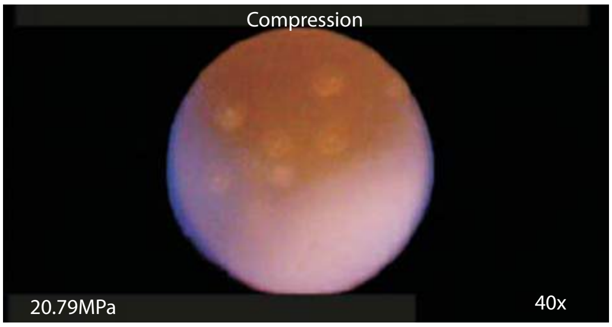

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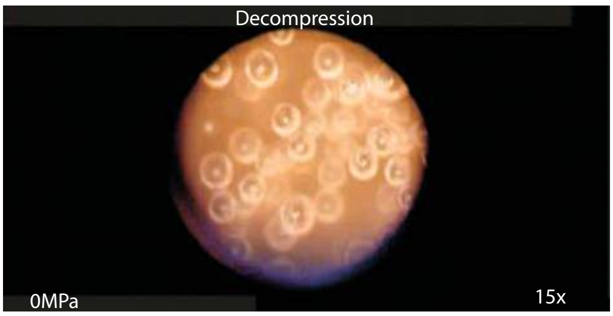

(5)

Fig.2. *Surviving of aphrons at compression and decompression [7]*

In contrast to conventional bubbles, which do not survive long past a few hundred psi, aphrons have been found to survive compression to at least 4,000psig (27.7MPa) for significant periods of time [3]. When a fluid containing bubbles is subjected to a sudden increase in pressure above a few hundred psi, the bubbles initially shrink in accordance with Boyle's Law. Aphrons are no exception. However, conventional bubbles begin to lose air rapidly via diffusion through the bubble membrane, and the air dissolves in the surrounding aqueous medium. Aphrons also lose air, but they do so very slowly, shrinking at a rate that depends on fluid composition, bubble size, and rate of pressurisation and depressurisation.

A very important criterion for aphron stability is shell viscosity. The middle shell must have a minimum viscosity in order to prevent the phenomenon known as the "Marangoni effect" that causes diffusion of water out of the shell into the bulk liquid [4, 5]. This thins and destabilises the shell. The rate of transfer of water is inversely proportional to shell viscosity. Therefore, addition of a viscosifier such as biopolymer is required. The viscosifier also serves to slow the flow of bulk fluid into loss zones. Because of the small amount of air incorporated in the base fluid (only 15% v/v at ambient temperature and atmospheric pressure) the density of aphron based fluid is similar to the density of the base fluid [6].

When aphron based fluid circulated through the system, rapid compression and decompression occurred. As shown in Fig.2, rapid compression of an aphron drilling fluid from 0MPa to 20.79MPa, followed by decompression back to 0 MPa, did not break the special structure of aphrons and resulted in essentially full regeneration of the aphrons. Rapid pressure cycling of aphron drilling fluids leaves most aphrons intact. Hence, the density of aphron fluids was maintained at about 0.8 to 0.9 [7].

3. Fluid invasion control

The encapsulated air within an aphron is compressed when circulated down hole. The micro-bubble volume decreases and internal pressure increases to an extent approximately proportional to the external pressure being applied. Once the drilling bit exposes a depleted formation, aphrons are brought together within the openings of low-pressure zones. There, a portion of the energy stored within each aphron is released, causing it to expand. The expansion continues until the internal and external pressures on the wall of the aphron are in balance. As the micro-bubbles are crowded into formation openings, external Laplace forces increase dramatically, causing aggregation, rather than coalescence, of the microbubbles, resulting in a solid-free bridge without adding solid lost circulation materials [6].

The effectiveness of the seal formed by the aphrons is dependent on the size of the openings and the degree of hydrophobicity of the aphron outer shell. Small openings and strongly hydrophobic/lipophilic aphrons promote sealing. Conversely, very large openings, e.g. fractures, will generate little or no capillary pressure and, hence, no seal may be possible except at the fracture tip [6].

Aphrons bridging mechanism is illustrated in Fig.3.

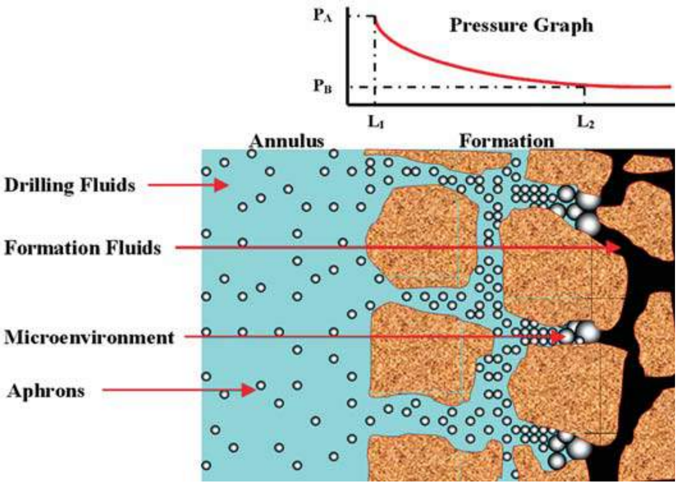

Fig.3. *Aphrons bridging mechanism [3]*

4. Composition of a typical aphron drilling fluid

Components of a typical aphron drilling fluid are shown in Table 1 [7].

As presented in Table 1, water or brine incorporated with surfactants and polymers will form stabilised aphron drilling solution.

Some properties of aphron drilling fluid are described in Table 2.

Table 1. *Components of a typical aphron drilling fluid*

Component	Function
Fresh water or brine	Continuous phase
Soda ash	Hardness buffer
Biopolymer blend	Viscosifier
Polymer blend	Filtration control agent and thermal stabiliser
pH buffer	pH control
Sufactants	Aphron generator
Biocide	Biocide

Table 2. *Some properties of aphron drilling fluid [3]*

Fluid properties	Unit	Expected quantity
Density	-	0.86 - 0.9
Plastic viscosity	cP	16 - 21
Yield point	$lb/100ft^2$	47 - 52
API Fluid loss	cc/30min	11
Low-shear-rate viscosity ($0.6s^{-1}$)	cp	120,000

5. Field experience of applying aphron drilling fluid

Brookey described the first use of aphrons in a drilling fluid application in 1998. In this case, the microbubbles were created as a minor phase in a water-based fluid. This system was used as a means of controlling lost circulation and minimising formation damage in a low pressure vugular dolomite reef zone. The microbubbles allowed the zone to be drilled to required TD, logged and drill stem-tested; this had not been possible previously [8].

This new system was applied in South America in an area where six wells were drilled using various fluids and techniques, including underbalanced drilling. Because of severe depletion, lost circulation and borehole instability, none of these wells was successfully drilled to TD. In contrast, the application of aphron technology in this field resulted in no drilling fluid losses and excellent wellbore stability even in previously troublesome shale sections. After drilling the first three wells in this field, the operator was able to eliminate the intermediate string and drill from surface casing to TD successfully [9].

Kinchen describes drilling in a highly vugular, fractured dolomite zone with good success, even coring with this fluid. Besides lost circulation control, these wells came on to full production in 4 days versus 30 to 60 days average in previous wells drilled with various fluid programs [10].

Gregoire chronicles a program of drilling with an aphron drilling fluid and controlling losses in a fractured granite zone, which resulted in open-hole production almost instantaneously without treatment. Besides instant cleanup, the production rates were much higher than had been seen before with any other drilling fluid [11].

Although aphron technology has been successfully used in about 300 wells over a period of several years, it was desirable to develop a deeper understanding of the way aphron drilling fluids work and to utilise laboratory techniques for optimising field applications. A two-year research and development program was undertaken under the auspices of the U.S. Department of Energy (DOE) to obtain laboratory evidence for the capability of aphron drilling fluids - primarily the polymer water-based system - to limit fluid invasion in permeable formations with minimal formation damage, and to provide a sound scientific basis for this behavior [12].

6. Lost circulation in Bach Ho and Rong oil fields

At depleted zones in the Bach Ho and Rong oil fields, reservoir pressure is lower than hydrostatic pressure and the reservoirs have cracks of various sizes (including macro and micro cracks). Therefore, lost circulation always happens in drilling processes with different levels at these depleted zones. According to the drilling history in the Rong oil field written by Vietsovpetro engineering for the period of ten years (1988 - 1998), there were 71 occurrences of lost circulation, with severe and complete loss accounting for 74,7%. However, until the present, there has been no effective treatment given for these problems.

The oil production has decreased in recent years, requiring drilling specialists and companies to find solutions to lost circulation problems. With the outstanding properties which have been studied and examined globally, aphron drilling fluid could be an excellent technique for depleted zones in the Bach Ho and Rong oil fields.

7. Conclusions

Aphron drilling fluids have shown the capability of effectively preventing loss of circulation in depleted zones. The applicability of this technique has been reported in seminars held by the Society of Petroleum Engineers, and it has been applied in some countries such as Yemen, Brazil and Mexico.

In Vietnam, this technique has not been studied and applied yet. Nonetheless, with excellent properties, aphron drilling fluid shows great potential for drilling at depleted zones in the Bach Ho or Rong oil fields, in which the oil production has declined sharply.

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POTENTIAL STRATIGRAPHIC PLAY IN THE WESTERN HA LONG BASIN FROM 3D SEISMIC INVERSION AND REGIONAL GEOLOGICAL CONTEXT

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Summary

There appears to be an actively working hydrocarbon system in the Western Ha Long basin (Beibuwan basin) during the Tertiary. All large conventional structures appeared leaking due to the late inversion tectonic activity. The only remain risk is the presence of a commercially sizable trap within the fetch area. With the latest 3D conventional seismic data and inversion products controlled by the information from two recent wells, a detailed litho-facial and depositional environment interpretation was carried out. The results outlined a series of areas with good reservoir potential multi-stack sand fairway surrounded and interbedded by the highly source potential lacustrine shale. These potential stratigraphic traps all have a high risk of lateral sealing. However, with the recent significant oil discoveries in similar settings and trap style in the Albert basin, East Africa, these stratigraphic plays become very attractive targets and are worthy of further studies and exploration.

Key words: *Potential stratigraphic play, Western Ha Long basin.*

1. Introduction

The study focused on the Western part of Ha Long basin within the geographic boundary of Block 101-100/04 of Vietnam. The basin, opened in rifting setting in early Tertiary time (Eocene - Oligocene) with a boundary faults to the North West. In late Tertiary time (Miocene to recent), the passive margin marine setting is dominant over the region. An obvious wrenching inversion has occurred recently from late Miocene, resulting in several present day structural closures which have been the main targets for exploration drilling to date [8].

A representative section across the Eastern part of Ha Long basin (Fig.1) clearly illustrates the petroleum play concept. Oil and minor gas/condensate have been discovered and produced in this region mainly from the reservoirs of Phu Tien, Dinh Cao and Phu Cu. Main source

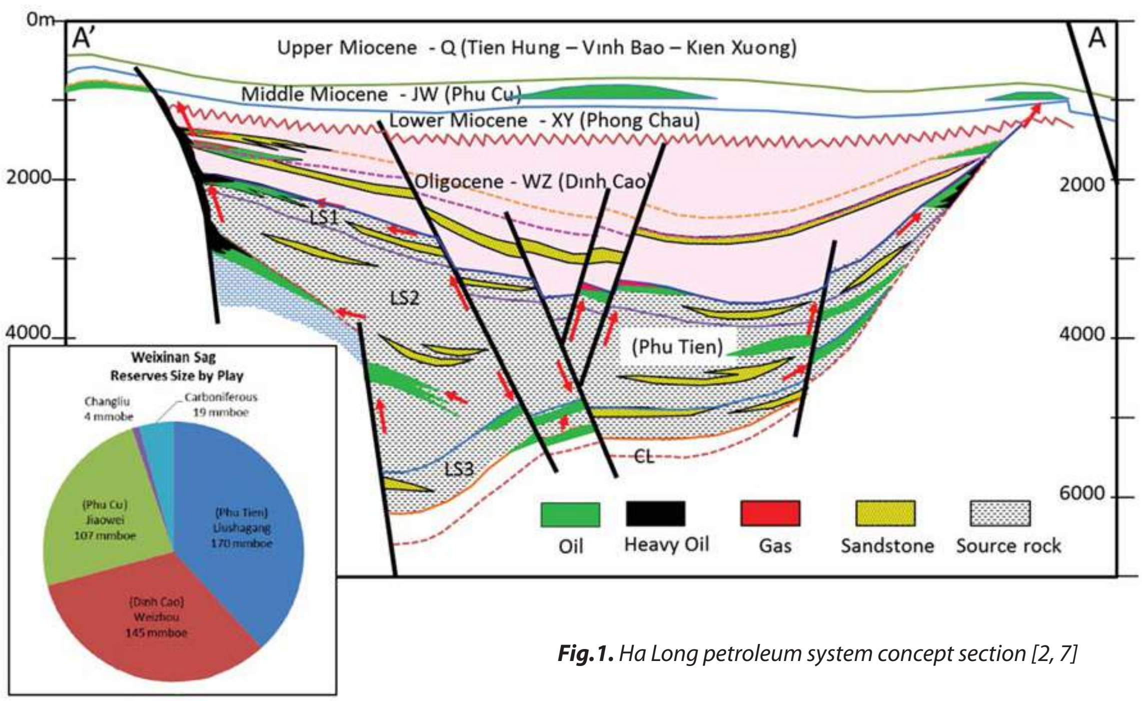

Fig.1. *Ha Long petroleum system concept section [2, 7]*

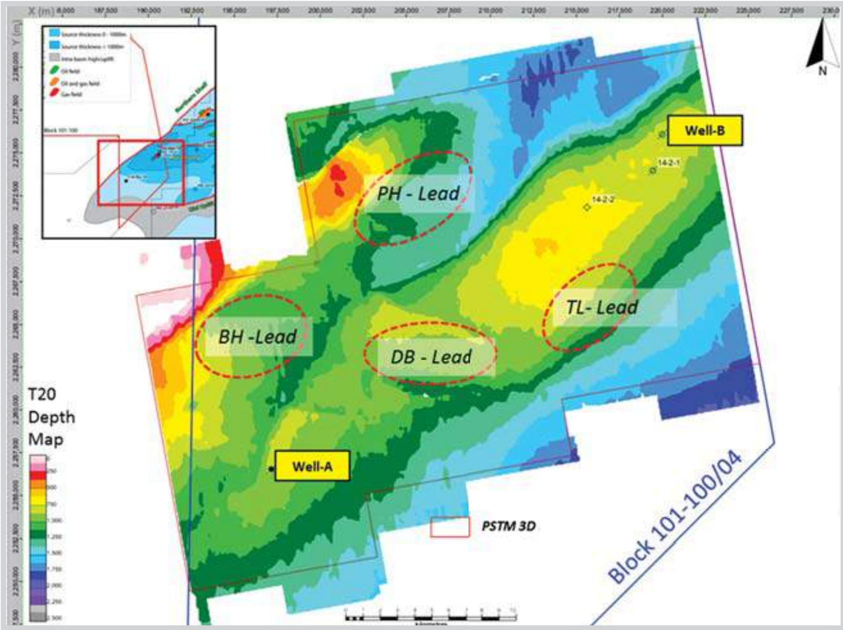

Fig.2. *Database and objects*

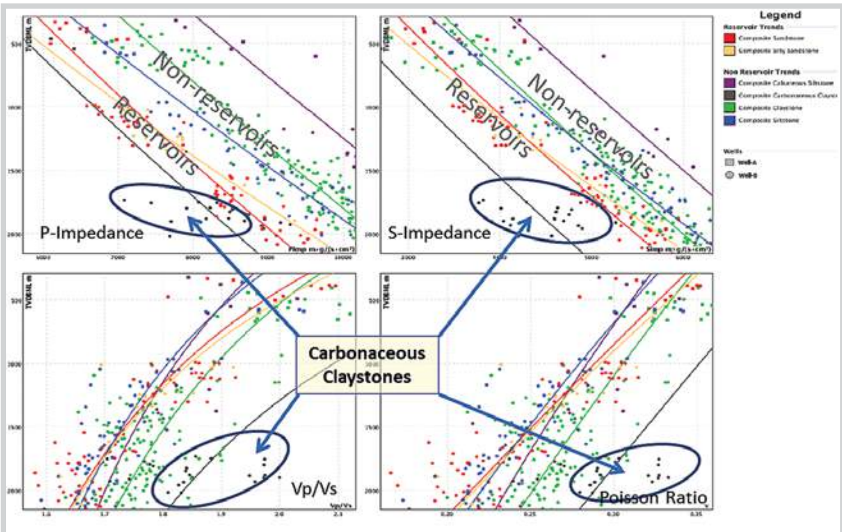

Fig.3. *Well elastic properties depth trend [1]*

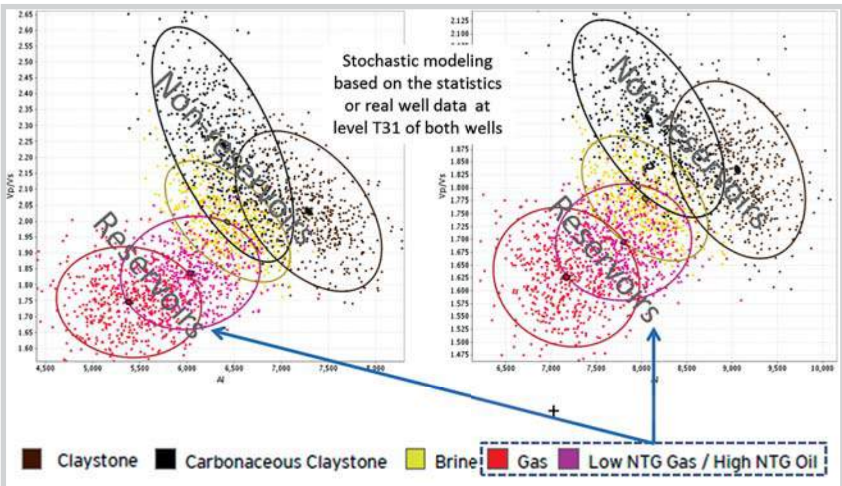

Fig.4. *Stochastic well modelling [1]*

rocks in the Eastern part of Ha Long basin are the Eocene lacustrine shales of Phu Tien formation. In the Eastern part of the study area, in addition to Phu Tien shales, the organic rich mudstones of Oligocene Dinh Cao formation are also considered matured source rocks since they are buried in the deeper depocenter [2].

2. Well rock physics and forward modelling

Database for the study (Fig.2) consists of 3D seismic cubes (~700km^2) acquired in 2007. The seismic dataset was pre-stack time migration processed. Final full stack and partial stacks (near, mid, far) were made available. Digital wireline data from only two wells Well-A and Well-B were accessible. The whole seismic cube was then pre-stack inversion processed by DownUnder GeoSolutions in 2011 [1]. Several cubes of inversion products were then utilised for this study.

The cross-plot of elastic properties of the two wells against depth (Fig.3) shows a clear separation between reservoirs (sandstones, siltstones) and non-reservoir rocks (calcareous siltstones, siltstones and clays) on P-Impedance (AI) domain. The only exception is the carbonaceous claystones encountered at the bottom section of Well-B. These claystones appear even "softer" than the sandstones. However, they are reversely located in Vp/Vs domain that appears even higher than the other claystones and shale. Pre-stack inversion products, which utilise both AI/VpVs, are therefore, a very robust and reliable tool for lithology (in this case is reservoirs) prediction.

The follow-on stochastic AI/VpVs cross-plot (Fig.4) with the modelled fluid substitution again confirmed the good separation between reservoir and

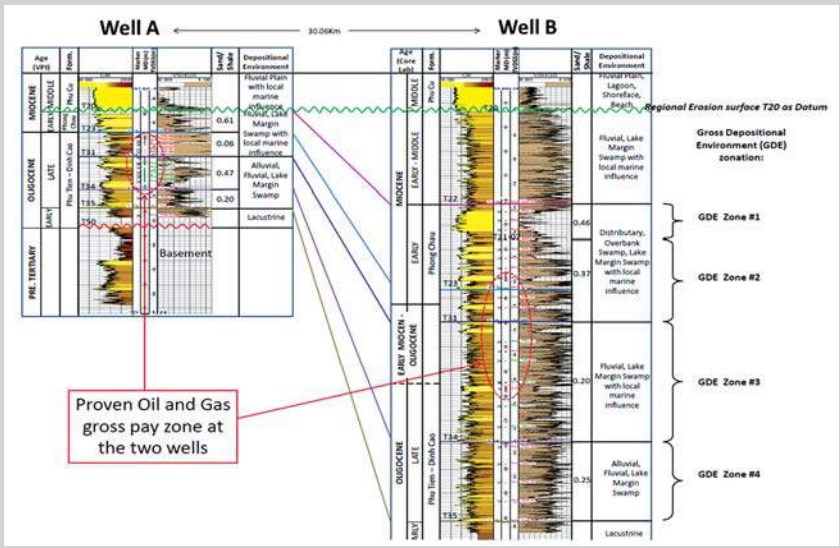

Fig.5. Well correlation and GDE definition

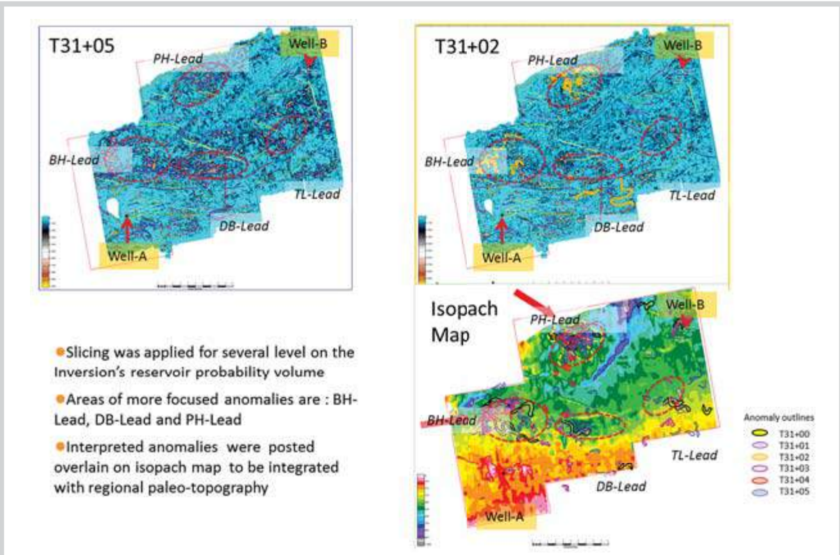

Fig.6. Slicing for inversion anomalies overlain on isopatch

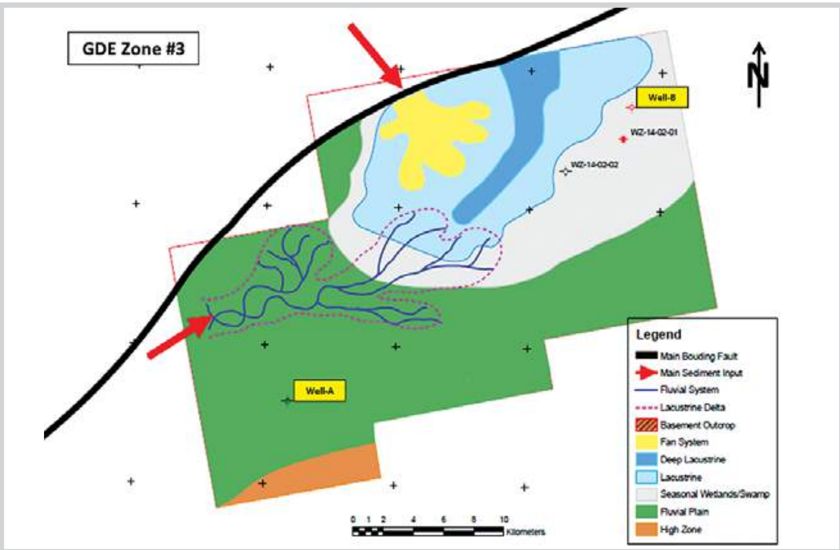

Fig.7. Gross depositional environment interpretation

non-reservoir rocks. Therefore, in actual inversion products interpretation, high net-to-gross (NTG) gas sand prediction (red) was summed with the low net-to-gross gas/high net-to-gross oil prediction (pink) to make a new cube named reservoir probability prediction. This cube is the best representation of the reservoirs' clear distinction from the other non-reservoir rocks.

It is also noted that the high net-to-gross gas is clearly delineated in the AI/VpVs domain. If good gas sand is actually present, it must be a very bright anomaly on this prediction cube. And in the pre-stack seismic domain, strong AVO class III should be obvious. The low net-to-gross gas sand/high net-to-gross oil sand is overlapped with the water wet (brine) sand. In the conventional pre-stack domain, moderate amplitude and mild difference between far and near should be expected.

3. Depositional environment and litho-facial interpretation

Depositional environment has been interpreted independently and conventionally based on regional and well data of Well-A and Well-B. Four GDE maps were produced for four stratigraphic intervals in an attempt to depict the gross depositional elements (Fig.5). Litho-facies were then interpreted on several stratal slices of the previously made reservoir prediction cube within each gross interval. The anomalies of high probability of reservoir (sand) presence were then outlined and stacked and overlain on the gross isopach map (Fig.6) for final GDE interpretation.

GDE map (Fig.7) shows two main sedimentary sources from the West and the North-Northwest and another secondary source from the East-Southeast. Due to variation of accommodation space and the source supply, the fluvial and delta system has been shifted to back/forward to shallower/deeper locations in the lacustrine. High energy environment from the West formed good reservoirs (point bars, mouth bars, and channel sands). Good reservoirs might also exist in a fan system at the Northwest dip side. Lateral seal, there, might be good owing to smeared shale along the boundary fault.

Fig.9 shows a Southwest-Northeast cross section through Well-A, Well-B and two heavy stack anomalies areas BH-Lead and PH-Lead. Inversion reservoir prediction (upper-left) shows high probability of several of stack sands deposited at BH-Lead and PH-Lead consistent with the previous litho-facial interpretation. The other section (lower-left) shows that there is low probability of good sand bearing gas presence in these two lead areas. The conventional near and far stacks (Fig.10) both show strong amplitude which highly related to the contrast between interbeded sand/shale interfaces expected at BH-Lead and DB-Lead. Far stack is just slightly stronger than the near stack. This does not support the presence of gas bearing sand. Oil sand, however, may still be present.

Fig.10 illustrates how a slice (T31+01) is tracking in section view along the inversion anomaly (reservoir probability) including the gas sand #2 encountered at Well-B. Fig.11 shows the maximum anomaly maps within the slice and its depth map. Small anomalies are observed at Well-A and Well-B which are very likely related to the gas pays founded at both wells at this level (top-right). No other

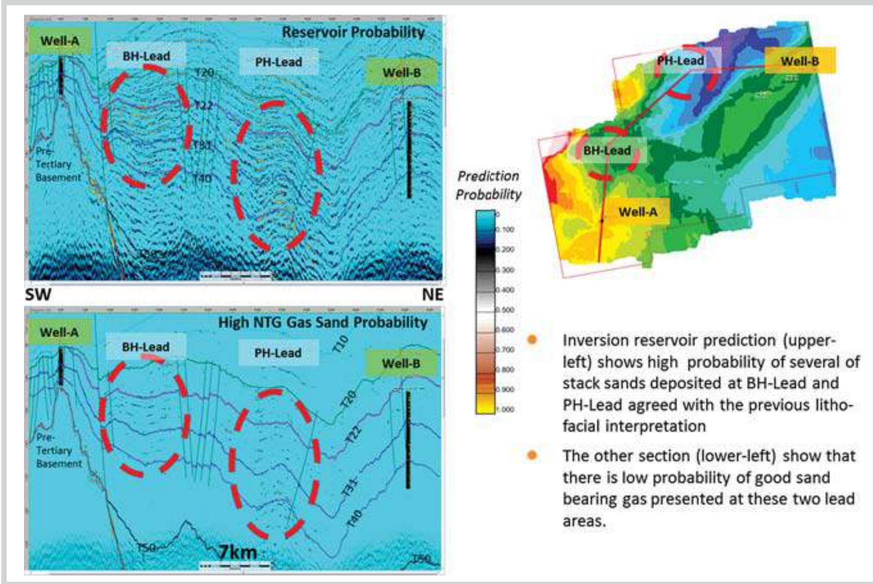

Fig.8. *Inversion's prediction Southwest-Northeast cross section*

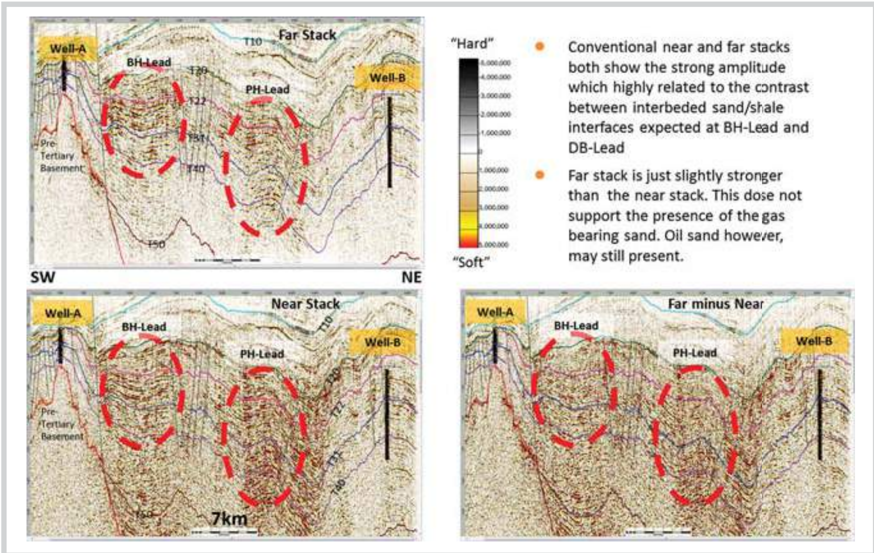

Fig.9. *Conventional partial stack Southwest-Northeast cross section*

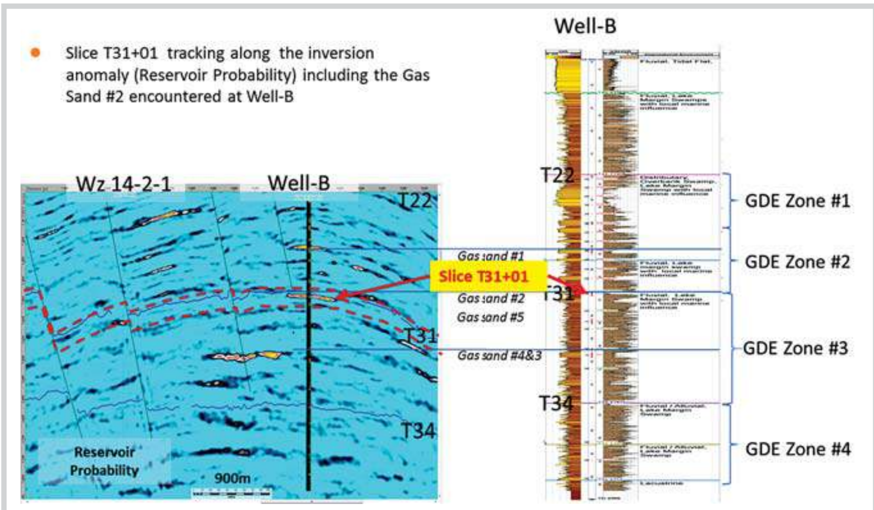

Fig.10. *Inversion slice tied to well data*

anomaly which may associate to high net/gross gas bearing sand on the whole 3D area was observed (top-right). The anomaly at BH-Lead and PH-Lead looks most bright (top-left), predicting a higher probability of good sand reservoir presence.

Fig.12 shows equivalent slicing of the T31+01 on the conventional partial stack data for additional interpretation. Far minus near slice (top-left) suggests more coal deposited in the South East of TL-Lead. Carbonaceous claystones are also expected down-dip of PH-Lead. The brighter anomaly on near stack (bottom-right) over the far (top-right) is also a better illustration of the above interpretation. Less coal is present at Well-B area as observed from the well data.

4. Analog geological model

An analog geological model is proposed which is the Albert lake basin at the border between Uganda and the Democratic Republic of Congo within the East African rift valley setting (Fig.13). The depositional setting is the lacustrine environment as in the Ha Long basin while the size is relatively similar. The analog proposed for PH-lead is the Kingfisher oil field (Figs.14. & 15 show the log correlation between the first two wells Kingfisher-1A and Kingfisher-2 at the pay interval. It can be obviously seen that Well-A and Well-B also show the same log motif, general net/gross ratio suggesting a similar depositional environment as those at Kingfisher wells.

5. Conclusions

Litho-facial and environment interpretations based on inversion products indicate the presence of a multi-stack good sand fairway

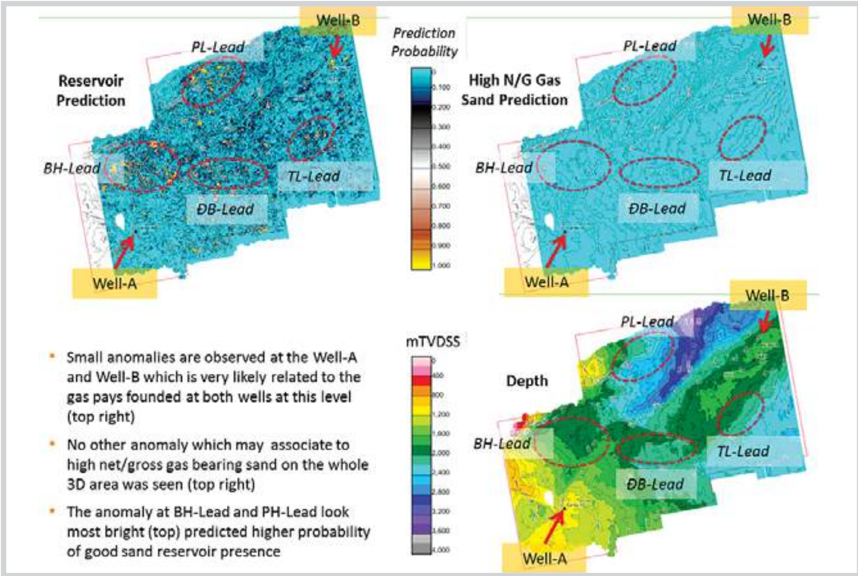

Fig.11. *Inversion slice anomalies interpretation*

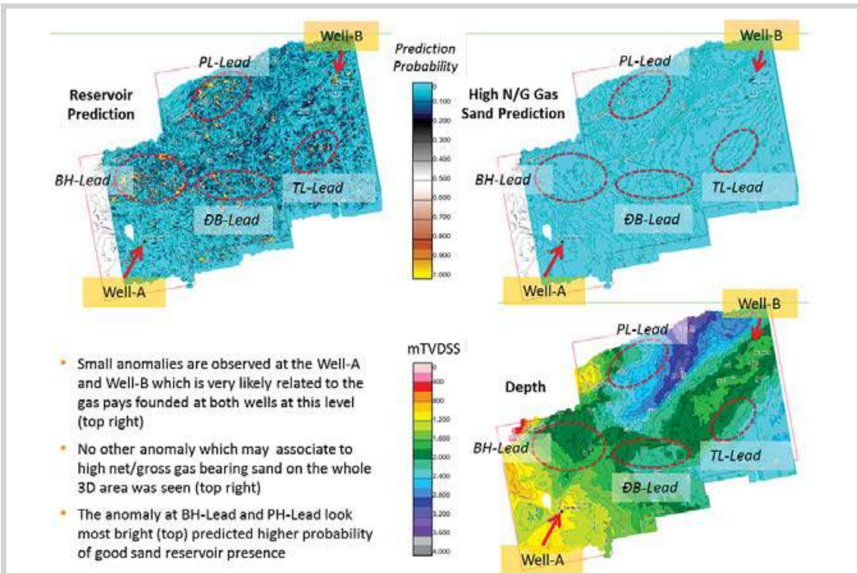

Fig.12. *Partial seismic slices interpretation*

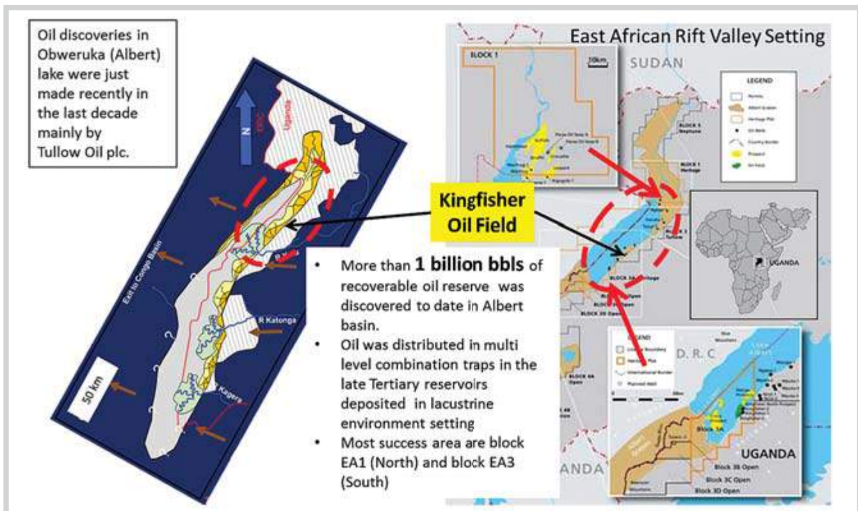

Fig.13. *Analog basin - Albert lake in East Africa [4]*

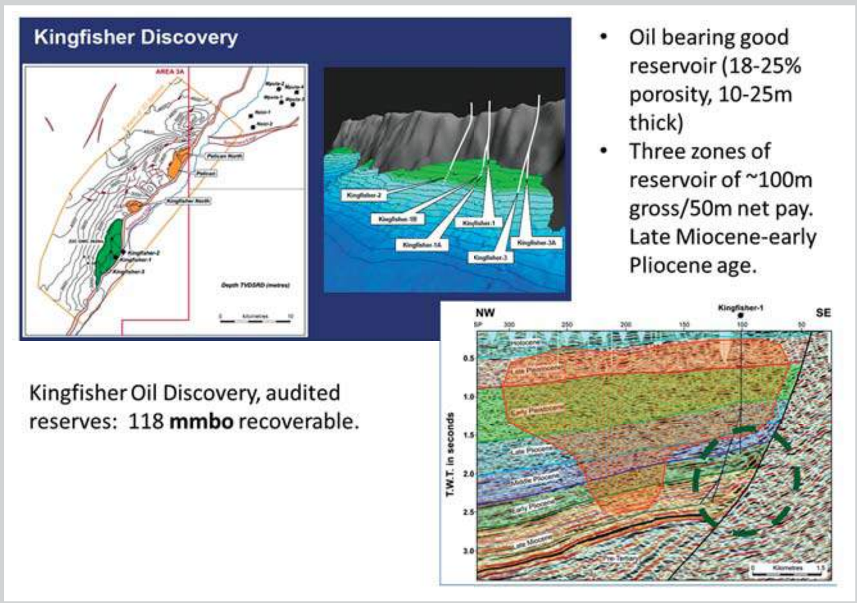

Fig.14. Analog field - Kingfisher oil field [4]

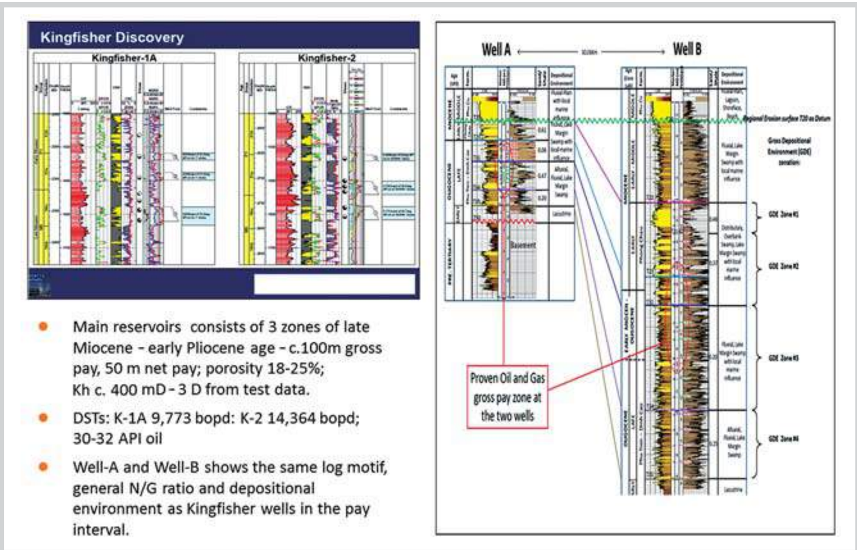

Fig.15. Kingfisher discovery - well data [4, 5]

developed and concentrated in four lead areas.

Conventional partial stack seismic also indicates that coal and carbonaceous claystones are widely deposited surrounding the PL-lead and TL-Lead.

Good sand fairway surrounded and interbedded by a lacustrine dominant carbonaceous claystones of Dinh Cao formation (already confirmed source rock potential) suggests these leads are very favoured in terms of hydrocarbon charging.

The analog from the Kingfisher oil field on similar settings in the Albert basin, East Africa supports the up-dip fault/stratigraphic sealing mechanism for this type of hydrocarbon trap.

Further fault seal analysis and updated basin modelling are recommended. However, this new stratigraphic play concept is obviously potential in the petroliferous Ha Long basin.

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