Have We Overlooked the Role of Deep Basin Hydrodynamic Flow in Flushing and Titling Hydrocarbon Contacts in the Nile Delta and Gulf of Suez?*

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Abstract

Tilted oil and gas-water contacts resulting from hydrodynamic flow have been well understood for over 60 years but are most commonly thought of as something occurring around basin margins from meteoric water flow into the basin. However, in any over-pressured basin, hydrodynamic flow is not only common, but certain to exist. This is due to the excess pore pressure at depth, causing expelled water to migrate vertically and laterally to areas of lower hydraulic head.

In recent years a number of clear examples of tilted contacts created by upward water flow from basin centers have been published from the Caspian and North Sea Basins, among others. In the Nile Delta, it has long been noted that many fields have gas-water contacts lower on the northern sides of traps relative to south, at multiple levels from Pliocene through Miocene and possibly, Oligocene levels.

The cause of these lower contacts is frequently attributed to compartmentalization from faults and facies, creating 'perched water' accumulations recognized from pressure-depth plots where gas zones are in pressure continuity but water zones are not. However, it is equally plausible that many of these pressure discrepancies can be resolved by simply applying tilted contacts due to deep basin water flow.

Examples from the Temsah Field (Nile Delta) and the Erdma area (Gulf of Suez) suggest that modeling hydrodynamic flow as a part of migration and entrapment may be an overlooked tool in exploration in both basins.

Introduction

Hydrodynamics are an important, but often overlooked, component of hydrocarbon migration and entrapment. The principles have been well understood since Hubbert's classic 1953 article (Hubbert, 1953). Several key articles and references summarize practical techniques for recognizing and quantifying hydrodynamic flow which can tilt hydrocarbon contacts assist in understanding the process in more detail

(Dahlberg, 1982, 1995; Dolson, 2016; England et al., 1991). Many of these references deal primarily with shallow basin meteoric water flow, but deep over pressured basins can create similar hydrodynamic flow and tilted hydrocarbon contacts. Recently recognized examples include those of Dennis et al. (2005), Ferrero et al. (2012), Muggeridge and Mahmode (2012), O'Connor and Swarbrick (2008), Riley (2009), and Swarbrick and O'Connor (2010). This article provides a general overview of Nile Delta, its exploration history and evidence for tilted hydrocarbon-water contacts. An additional example is shown from the Gulf of Suez Basin.

In the spirit of and AAPG GTW, this article is designed to generate new ideas and discussion, rather than be a full treatment of these topics appropriate for a peer-reviewed journal.

North Egypt Overview

Egypt's geological history and petroleum plays are more thoroughly documented in Dolson et al. (2014) and Dolson et al. (2001). Recent publications focus on the Mediterranean offshore potential (Belopolsky et al., 2012; Bentham, 2011). Gulf of Suez geology has been extensively documented, but the most classic article is that of Patton et al. (1994). Field studies in both basins are contained in classic volumes Matbouly and Sabbagh (1996) and Moussa and Matbouly (1994).

Jurassic rift basins extend northeastward under the Nile Delta cone. Only a handful of wells penetrate to the Oligocene section and the deep structure and stratigraphy and deepest petroleum system is largely unknown. Deep exploration to the Oligocene section did not commence until the discovery in 2003 of the Raven Field. Well control on Figure 1 shows key Oligocene and older penetrations which provided a framework for understanding the deeper potential.

Nomenclature is summarized in Figure 2 and the exploration creaming curve up to 2016 in Figure 3. The 2015 discovery of the giant Zohr Miocene reef trend near Cyprus has created a 'game changing' new exploration play in the deep water Nile Delta, with 30 TCF of reserve in one field (ENI, 2015a, b).

A closer look at the creaming curve of Egypt shows how important Nile Delta exploration has been for Egypt, with a still rising rate of significant field discoveries boosting production and replace the spectacular growth of the Gulf of Suez from 1965-1989. A more detailed look at the Nile Delta creaming curve (Figure 4), shows that the awarding of gas rights offshore in deep water was the primary cause of the rapid reserve growth.

The Zohr concept was overlooked by Industry despite its easy recognition on seismic sections near the Eratosthenes seamount (Figure 5). The Zohr accumulation is biogenic gas. Most of the other fields in the Nile Delta, particularly in the deeper Oligocene-Miocene, are from thermogenic sources. The history of concepts leading to deep exploration is outlined in Dolson et al. (2002) and Dolson (2005).

The overall geometry of Nile Delta depositional during the Oligocene is shown on Figure 6. This article focuses on the hydrodynamics and pressures of the deeper play. Recent drilling has discovered a number of giant deep structural and combination traps. A number of paradigms had to be broken to make the deeper play successful, including a perception of lack of source rock, too high a pressure system and a lack of porosity at great depth. All of these paradigms have been broken and Darcy range permeability and high porosity have been found as deep as 6 kilometers. Most significantly, the deeper trends are over pressured, setting up conditions for deep basin water flow and the potential for tilted hydrocarbon contacts.

A Brief Discussion of Hydrodynamic Flow and its Recognition

The reader is referred to the publications cited earlier for more detail. Figure 7 shows the major types of basin waters and their movement into basin flanks (meteoric) and upward from deep basins. Pressure vs. depth plots can be used to recognize seals but also quantify the direction of water flow in a basin as illustrated on Figure 7, by breaks in the water gradient lines where over-pressured seals are encountered.

Water flow is gravity and potential energy driven (Figure 8). It is incorrect to say water flows from high pressure to low pressures. An example is a cup of coffee. The highest pressure is at the base, and the lowest at the top. If that were true, coffee could not be contained in the cup. But tilt the cup over and out flows the water, moving from high potential energy to low.

Hydrocarbon tilting (Figure 9) occurs when different density fluids of oil, gas, and water encounter one another in a trap where the water is flowing. This multi-phase system causing tilt is show on Figure 10. Quantification of hydraulic head is relatively simple, as shown in Figure 11. Pressure-depth plots are key to recognizing hydrodynamic flow and its magnitude.

Figure 12 shows how to recognize a tilted contact on a pressure vs. depth plot. The hydrocarbon phase will plot on the same density gradient, but the water points will be higher pressure and off to the side. This is covered quantitatively in Dolson (2016) and England et al. (1991).

A pressure-depth of the Nile Delta is shown on Figure 13. Seals are shown as horizontal gray lines, below which a number of over-pressured gas fields exist. The excess pressure in the over-pressured basins provides the energy for elevated hydraulic head (shown by blue dashed lines extending above the y-axis with a slope equal to the density of water (.433-.45 psi/ft). Upward flow from over pressure to normal pressure drives the deep basin hydrodynamic system.

Effective stress exerts a major control on porosity preservation and development. In Figure 14, some low porosity fields (red) are normally pressured at depth, but under high effective stress (the difference in psi between the overburden line and the pore pressure). In contrast, fields like the Miocene in Temsah have much higher porosity, but lower effective stress due to higher pore pressure. This is also shown on a pressure vs. porosity plot on Figure 14, with high porosity systems lying above the normal compaction trend line. This is one reason why deep, high-porosity and permeable Oligo-Miocene sandstones are continuing to be found a great depth in the Nile Delta.

Perched Water vs. Hydrodynamics

Figure 15 illustrates an example of perched water, where pockets of water remain in some structural and stratigraphic positions in reservoirs, creating multiple gas-water contacts, but pressure continuity in the gas or oil phase (Marcou et al., 2004). Pressure/depth plots in these settings, more importantly, look identical to those of tilted contacts in hydrodynamic settings. A number of publications provide additional examples (Cade et al., 1999; Dennis et al., 2005; Ferrero et al., 2012; Kendrick, 1998; Muggeridge and Mahmode, 2012; Shang et al., 2009).

The author's experience in both the Gulf of Suez and Nile Delta when dealing with such accumulations was to initially describe the variable water legs as perched. In the Nile Delta, gas-water contacts are frequently deeper to the north than to the south but with the gas phase plotting on one gas gradient. Until the mid-2000's this was widely accepted as evidence of perching in complex turbidite slope channel reservoirs, with excellent examples given in a giant Pliocene field (Samuel et al., 2003).

Figure 16 shows an evolution of thought on a giant gas field in the North Sea, where a common gas gradient through reservoirs showed the deepest gas encountering apparent water bearing layers that were over pressured, but at a density that was higher than sea water. That observation caused Amoco staff to interpret the plot as an indication of perching. A well was recommended downdip and subsequently found deeper gas in pressure continuity with the shallow gas column. This has been reinterpreted by Ferrero et al. (2012) as actual hydrodynamic tilt based on more regional pressure maps and application of hydrodynamic modeling (Figure 17). Significantly from an exploration standpoint, the discovery of the deeper gas to the south was only made possible by careful integration of rock petrophysics and pressure analysis in a way that caused another well to be drill. This field could easily have been abandoned or undervalued in 1999 by assuming the log-based gas-water contact was the limit of the pool. Other examples are shown in Figure 18 and Figure 19, from the North Sea and Caspian Basin.

A similar situation existed in the Temsah Field, where the discovery in 1977 encountered an over-pressured gas-water contact high on the structure. Subsequent drilling found deeper and deeper gas contacts to the north, but with over pressured water legs. The author, like others working this field, recognized its larger size in the later 1990's and early 2000's, but assumed the water legs were from a complex set of perched water levels (discussed later). In the mid-2000's, a BP geologist proposed a hydrodynamic tilted gas-water model, something that in hindsight seems much more reasonable and simpler.

Nile Over-Pressured System and Pressure Regressions

Understanding the deep pressure system in the Nile requires a regional synthesis of well pressures and pressures from seismic. Figure 20 illustrates recognition of a pressure regression when pressure-depth plots find a deeper zone with less pressure than on overlying horizon above another seal. This diagram also indicates how over-pressured or shallow gas can be column-limited when the gas pressure at the top of column exceeds the fracture gradient of the rock. Pressure regressions, therefore, are critical in deep plays to avoid situations where pore pressure exceeds the fracture gradient of the seal.

Figure 21 shows an example of a dry hole caused by a general lack of sand but, when present at depth, high over pressured, to the point that a gas column could not be contained due to top seal failure, reached within a few meters of column.

If thick, well developed reservoirs are encountered, particularly if 'plumbed' to lower pressure across faults or to outcrops or unconformities, then a type of 'pressure relief' is develped which allows for lower pressure in the reservoir vs. the surrounding shales. Thin, highly lenticular and isolated sand bodies encased in highly overpressured shales (like in the Bougaz example in Figure 21) generally will not have pressure regressions. In contrast, thicker zones, like those in the Temsah Miocene reservoirs, are under pressure regressions relative to the encasing shales (Figure 22).

Understanding the deep Nile hydrodynamic system requires regional perspective. Figure 23 (Heppard et al., 2000) shows three main pressure trends: (1) normal pressure along the coast and outboard of the main Nile in deep water, (2) the over-pressured Nile cone where the Pliocene-Pleistocene sedimentation rate is very high, and (3) the incised Abu Madi-Baltim complex Messinian Canyon which bevels into the deeper over-pressured Serravallian shales. Fluid flow is from the excess pressure to lower systems as shown. These are also shown schematically on Figure 24. The highest pressure gradients in the Nile Delta are where the Pliocene-Pleistocene sedimentation rate is high in the core of the delta (Figure 24).

Some, but not all, of the pressure regressions noted in the deep Miocene-Oligocene play can be attributed to the incision of the 550 meters or greater erosional canyons of the Messinian unconformity (Figure 25). Recognition of pressure regression in highly over-pressured Oligocene reservoirs by top-seal breach at the Messinian unconformity was a key factor in the discovery of the giant Satis Field.

A paradigm of ‘no Oligocene source rock’ existed with many explorers working the Nile Delta through the 1990’s. However, non-commercial oil had been discovered in the Oligocene at the Tineh Field and wet gas at the Lower Miocene at the Qantara Field (Figure 26). Residual gas and shows were noted in Oligocene slope channels in the Habbar-1 well, drilled in 1999, so there was clear evidence of migration from deeper sources in these horizons (Figure 27).

The Habbar-1 well was drilled on a large faulted structural closure. High quality Oligocene reservoirs were encountered but only residual gas (Figure 28). This well was used by many geoscientists as ‘proof the Oligocene does not work’. The residual shows confirmed migration through the trap. For background on how to recognize residual shows, see O'Sullivan et al. (2010), and Dolson (2016).

Seismic showed clearly that the crest of the Habbar-1 structure was overlain by the Abu Madi Messinian erosional unconformity, above which pressure systems were much lower. Additional structures like the deep Satis closure, however, were not breached and would thus make excellent targets for enhanced seals and favorable migration pathways into reservoirs predicted to be in pressure regression. The Satis discovery found gas/condensate as predicted, and with a pressure regression.

As a side note, cores in the 2008 Satis well confirmed high quality source rock in the Oligocene section, confirming the presence of deeper source beds, sources which also match trapped fluids in many shallow fields in the eastern Nile Delta, confirming strong vertical and lateral migration (Figure 29) (Dolson et al., 2014).

Tilted Contacts, Nile Delta

The first place a large number of tilted gas/water contacts were noted in the Nile Delta was on the western basin plays around the Sequoia Field complex (Figure 30). All of the shallow fields shown have gas-water contacts higher on the south end than the north. Although the regional pressure system at this level is not as well known, the overall pattern of deeper pressures to the southeast and normal pressures to the northwest exists.

Cross et al. (2009) interpreted the water at the base of the reservoirs as perched, based on pressure data (Figure 31). However, it is just as reasonable to simply tilt the contact to the northwest, and perhaps more easily explain what is clearly a phenomenon that extends beyond this trap.

Quantifying Tilt in the Temsah Field Using Hydrodynamic Mapping

Figure 32 shows a simple conversion from mud weight to pressure gradient in psi/ft. This regional map can be converted to a deep basin flow potentiometric map and used in migration and trap analysis using Trinity software (www.zetaware.com).

Speculated regional flow patterns from over-pressure to normal pressure are shown of Figure 32. The Temsah Field complex is over pressured, but with much lower pressure located to the northeast. The Temsah structure itself is a relatively simple northwest-southeast trending anticline broken up by several faults (Figure 33).

The 1977 Temsah-1 discovery well, however, showed the anticline was not filled to spill, with water high at the crest of the structure (Figure 34). Subsequent drilling found more and more gas to the northeast, presumed to be ‘perched’ as in the example shown by Cross et al. (2009) at Sequoia Field.

The reservoirs themselves are complex stratigraphically, consisting of highly variable slope channels draped over a 4-way closure (Dolson et al., 2002). At the time these systems were observed, the lenses of water were dismissed as perched water which would have little impact on production.

Pressure vs. depth plots clearly showed the gas column in pressure continuity (Figure 35), but with high pressure water legs plotting to the right on the diagram. Is it perching or tilting? The best way to tell is simply to model the trap using a potentiometric surface or excess pressure layer combined with the structural geometry.

Figure 36 is the regional mud weight map converted to psi/ft and then converted to a potentiometric surface map. It clearly shows elevated head to the southwest, with water flow to the northeast.

If the system were hydrostatic and migration modeled without flow, then the Figure on the left in Figure 37 would have the structure filled to spill. But when the hydrodynamic component is added, the column is flushed to the northeast with a much deeper contact with the crestal portions wet (right map in Figure 37). This Trinity migration with hydrodynamics model is a very close fit to the known accumulations.

The model supports a hydrodynamic tilt for this field, and by inference, for many of the other fields in the Nile Delta (Figure 38). The explorer is left to wonder how many small fields or other traps with water high on the trap are actually up-dip of deep accumulations in the same hydraulic system. The method of using Trinity software to model migration under hydrodynamic conditions is discussed in He and Berkman (1999) and illustrated with simple gridding software in Dolson (2016).

An example of just one area to re-investigate is shown in Figure 39, where a Pliocene bright spot on a fault trap was drilled but found producible gas over residual gas and water. The flat spot on the Ringa-1 well turned out to be a paleo gas/water contact as interpreted by Heppard et al. (2000). The subsequent reserves were reduced by over two thirds.

But is it? The position of high pressure in the well and low pressure across the fault was used to explain the residual gas. But could this be an Omen-Lange analogy or a Temsah analogue as discussed earlier? Could the contact simply be tilted to the northeast? Only another well can tell.

Gulf of Suez Example: Erdma Area

The prevailing wisdom in the Gulf of Suez is that the sub-salt tilted fault blocks have flat hydrocarbon-water contacts. That may not necessarily be the case.

The Erdma area Miocene sandstones are deep water, distal deltaic sandstones of the Kareem Formation that form a 150+ gas and condensate field. The S40 level sandstones are on a high, gently folded and faulted nose with a reservoir pinch-out to the northwest, on the down-dip end of a large Miocene delta (Figure 40). The shallow gas pays are located over a deeper Lower Cretaceous Nubia horst block that was discovered in 2003 from an integration of oil shows and test data in two key wells, forming the Saqqara Field (Figure 41). The shallower gas field is shown with red circles on Figure 41.

Figure 42 shows a pressure vs. depth plot of the S40 sand interval. As in the cases shown previously, the gas gradient is continuous between the wells, but the Erdma-4 well has a gas-water contact shallower than the Erdma-1 well.

Seismic resolution below the shallower salt and sand layers above the S40 horizon is degraded and typically full of multiples which mask subtle faults and the details of the structural geometry. The difference in gas-water contact between the Erdma-1 and 4 wells caused the field for nearly 20 years to be viewed as isolated sub-seismic-resolution fault traps and compartmentalized reservoirs. None of these shallow zones were produced until acreage was acquired by Amoco in the early 1990’s and an interpretation of perched water was applied to the pressure plot shown in Figure 42.

Prior to this time, the reserves per well were kept small, with great uncertainty as to the extent of each pool. The gas recoveries are progressively deeper on the field to the southeast and a deep basin exists northwest of the trap. Amoco twinned the Erdma-1 well, which had tested, in 1985, high rates of gas and condensate but was plugged and abandoned by BP after concluding none of these wells were part of the same accumulation. Two weeks of extended tests confirmed the well had only one pressure barrier (suspected to the southwest toward a major fault) and had a minimum of 40 BCF reserves. The twinned flowed at high rates for over 18 months and became one of the most prolific wells in GUPCO, with little to no pressure drop (Figure 43).

Although hydrodynamic maps are not available due to relatively sparse basinal data, another explanation is possible for this trap (Figure 44). A simpler solution is tilting southeastward of the gas/water contact. This solution is less complicated than the perched model, and with the steep basinal dip to the northwest off the structure, it is possible the deeper graben to the northwest is mildly over pressured, leading to the mechanism of upward basin water flow to explain a possible tilt to the southeast.

Egypt Yet-to-Find

No matter which way you look at the statistics and geology, there is a lot of room to grow new fields in Egypt. In the Nile Delta, the shallow Miocene reefs, but ultradeep-water carbonate trend will add significant new resources. The deep structures will continue to be found. In the Gulf of Suez, and perhaps parts of the Western Desert, more surprises and reserve growth may occur through a re-look at pressures and fluid context with an eye to possible hydrodynamic involvement.

There may be more than 38.6 BBOE (224 TCF) of reserves left to be found in Egypt (Figure 45). It seems clear from the last decade of drilling and these examples that understanding hydrodynamics will help unlock new plays and prospects.

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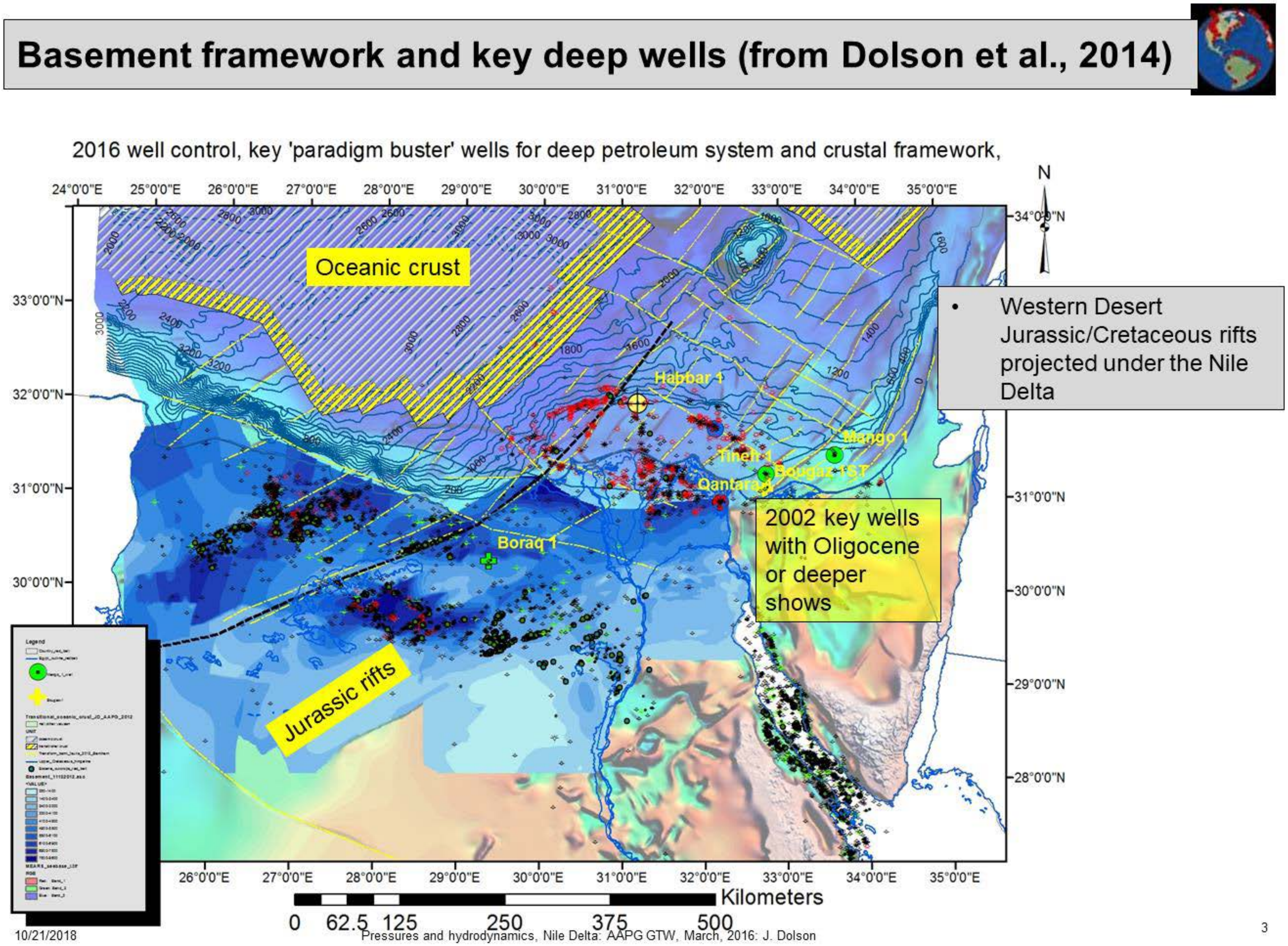
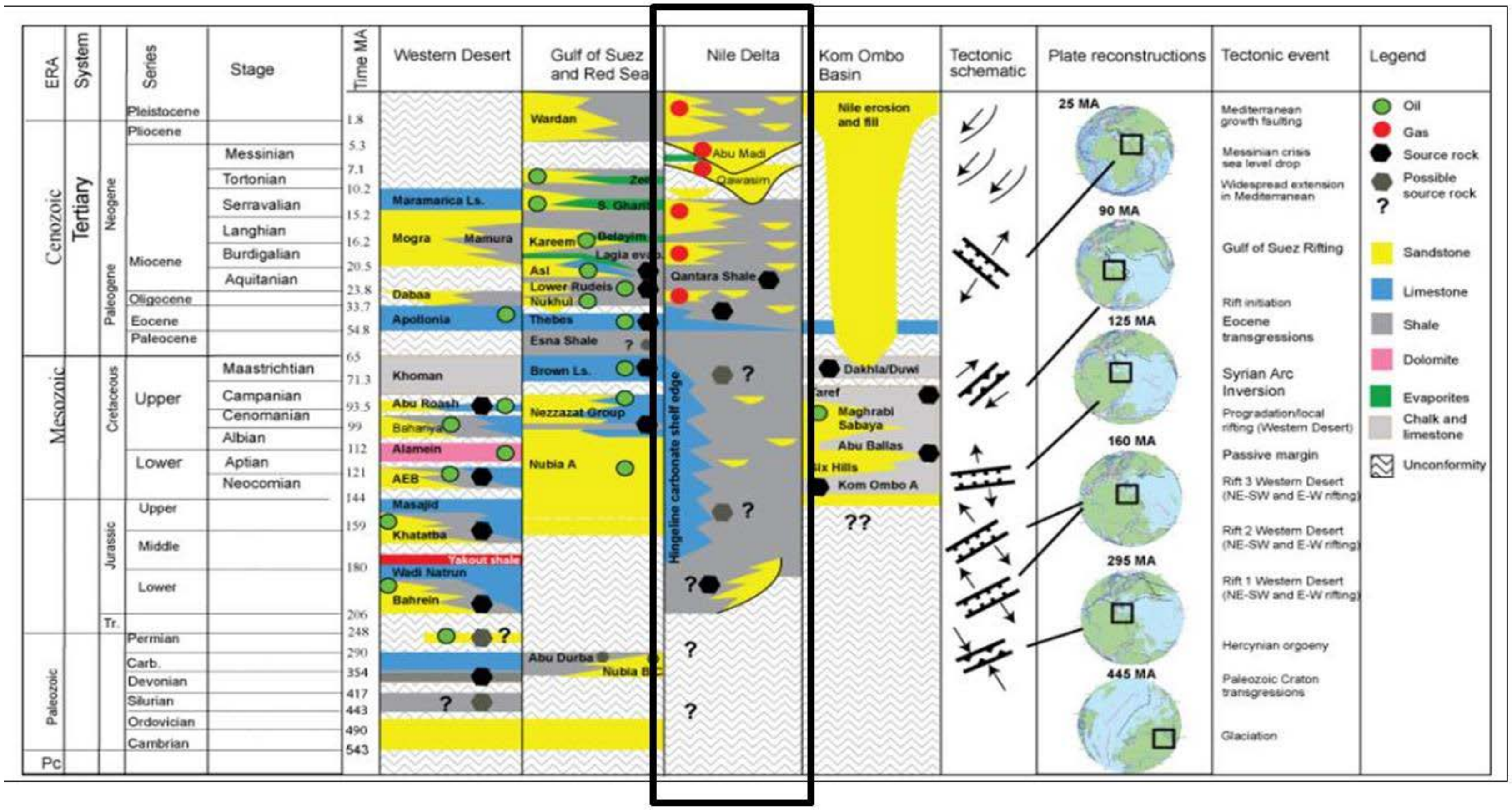


Figure 1. Generalized geometry of Jurassic rifts, onshore, Western Desert, extending northeastward under the Nile Delta.

Tectono-stratigraphic framework: 2014



How deep does the petroleum system go offshore in the Nile Delta?
Shows of hydrocarbons as deep as Lower Cretaceous.

Figure 2. Generalized Egypt stratigraphy.

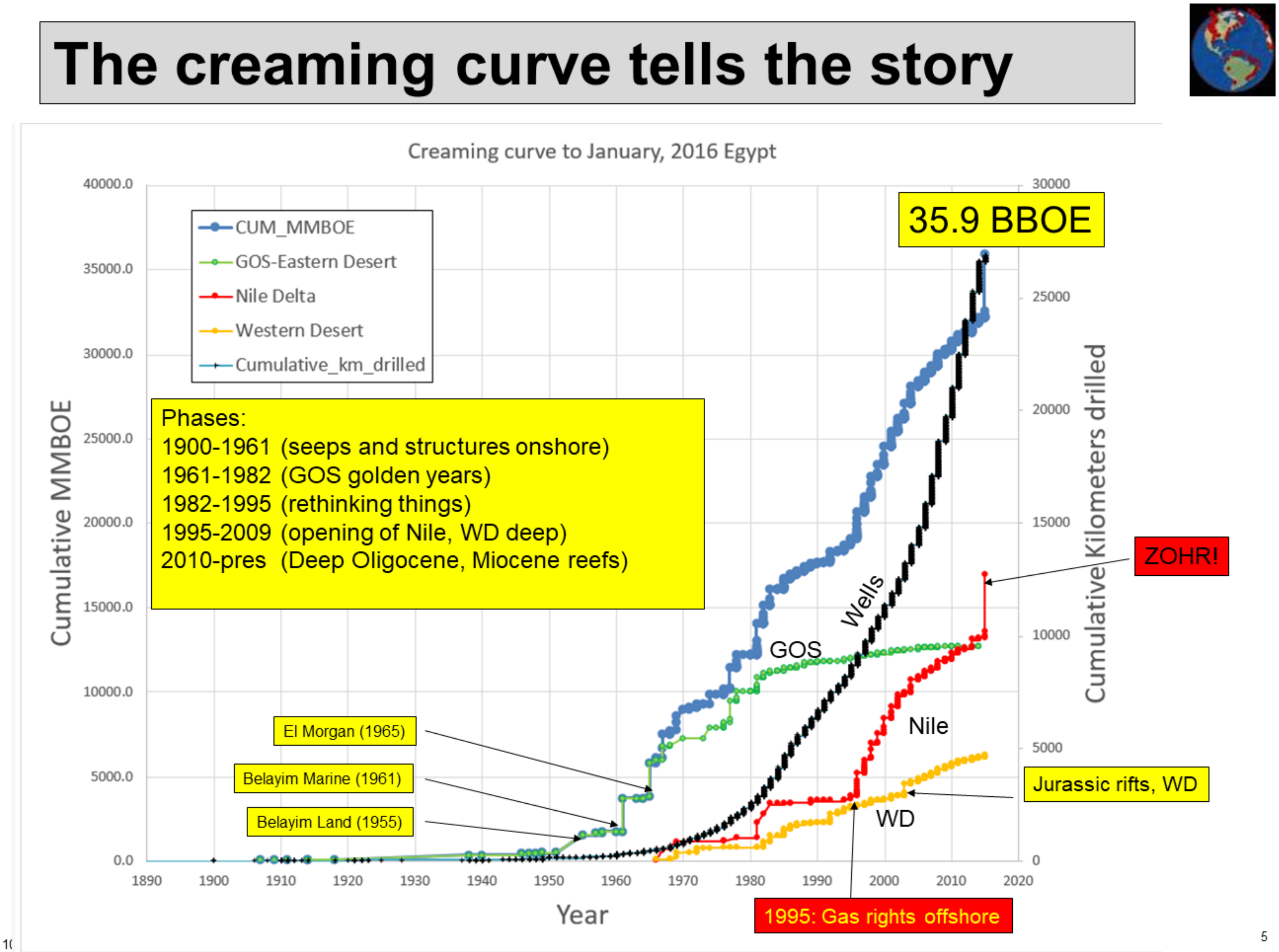


Figure 3. Egypt creaming curve.

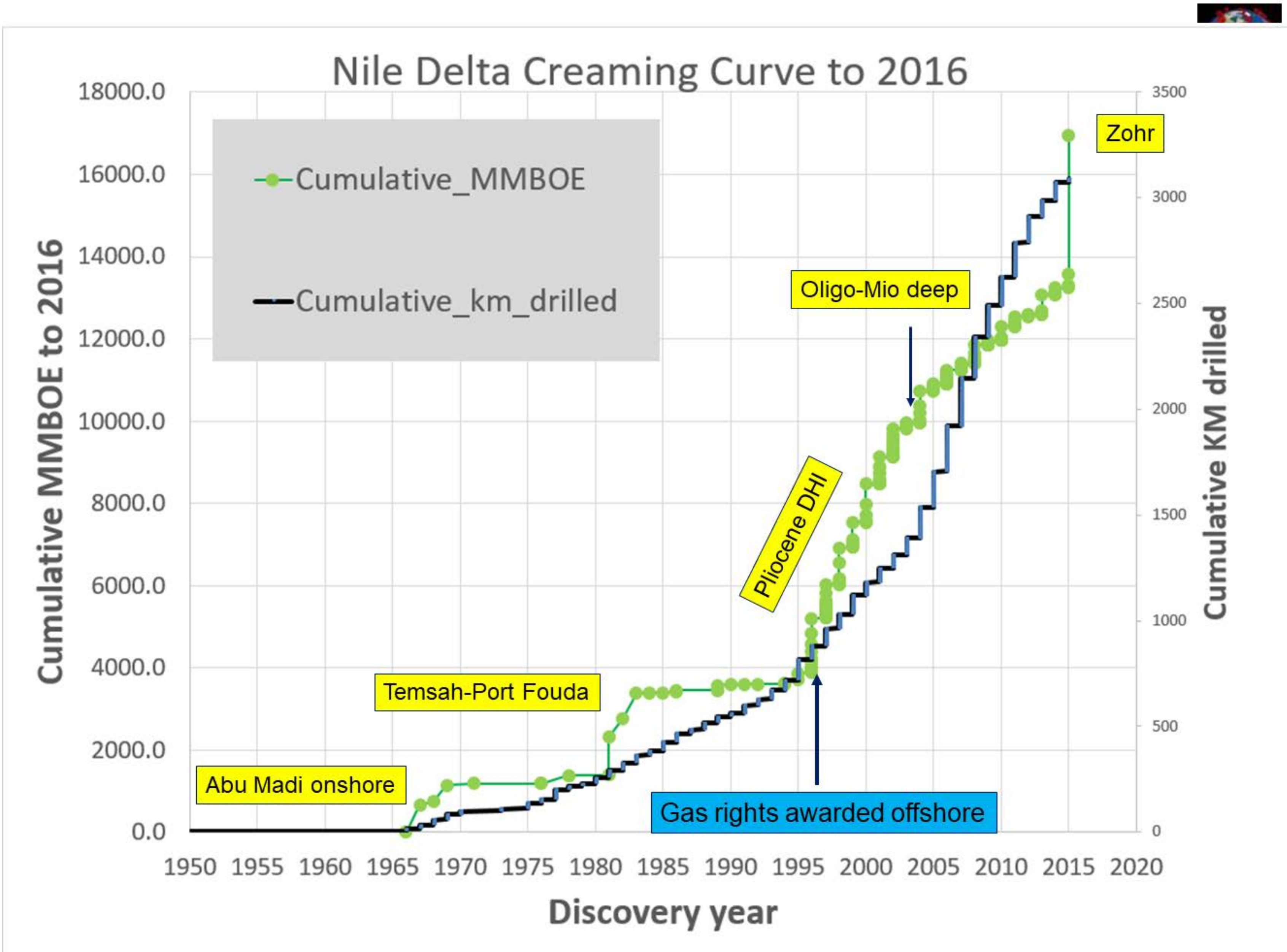


Figure 4. Nile Delta creaming curve and exploration advances.

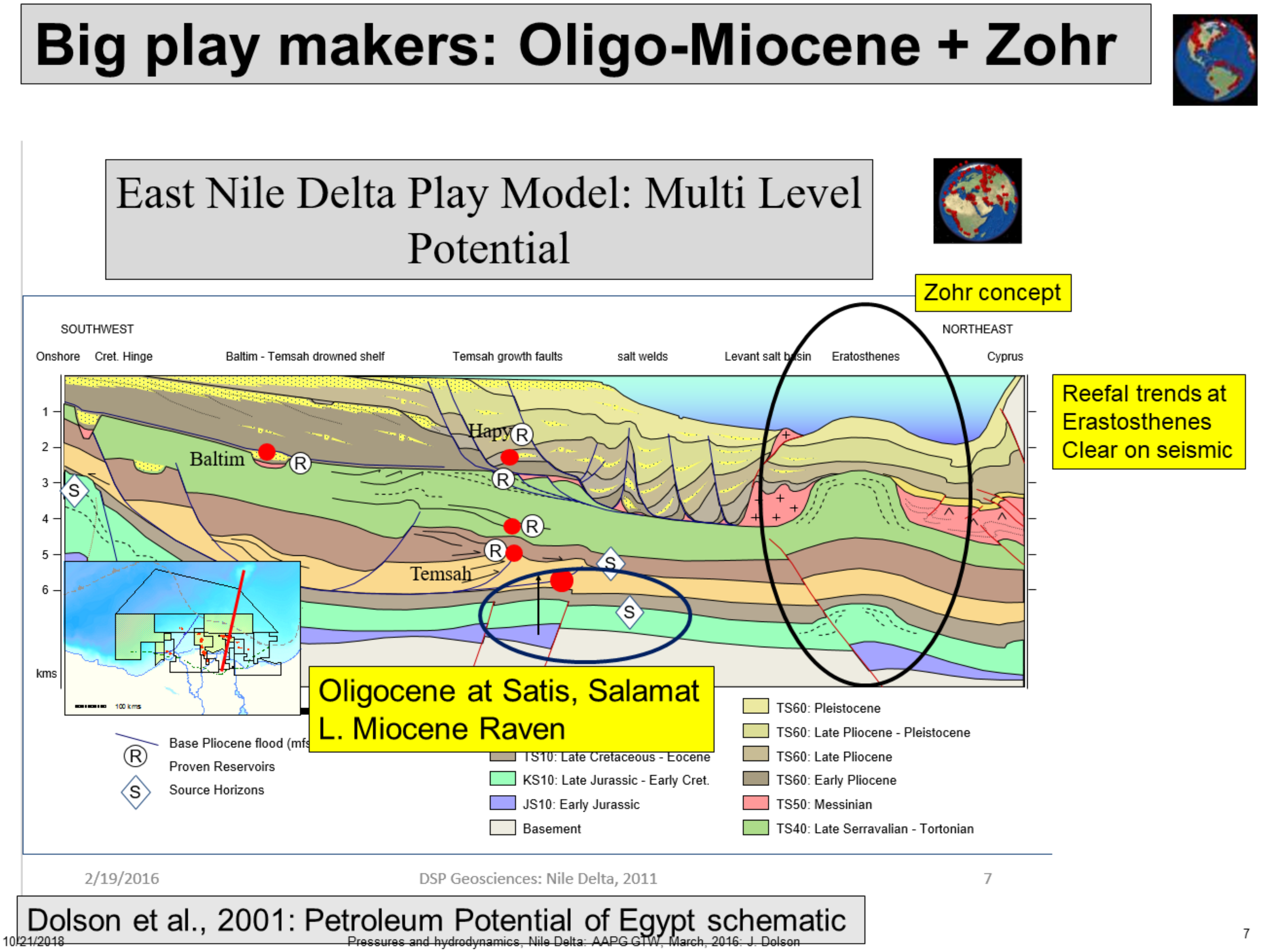


Figure 5. Nile Delta play diagram highlighting deeper play concepts and the Zohr Miocene reef concept. This figure is currently undergoing revision as new details of the Zohr discovery are released.

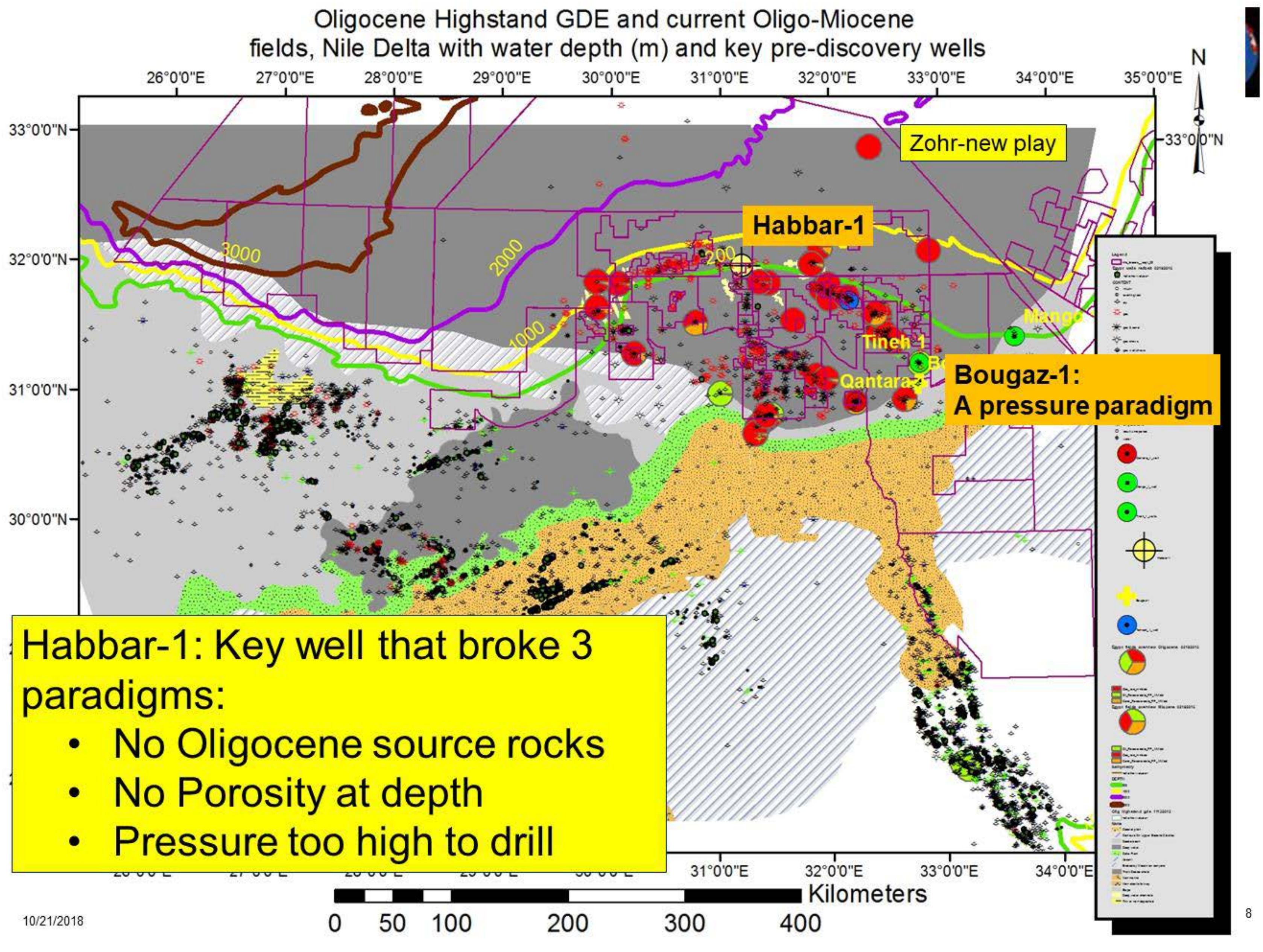


Figure 6. Oligocene GDE and key Nile delta fields.

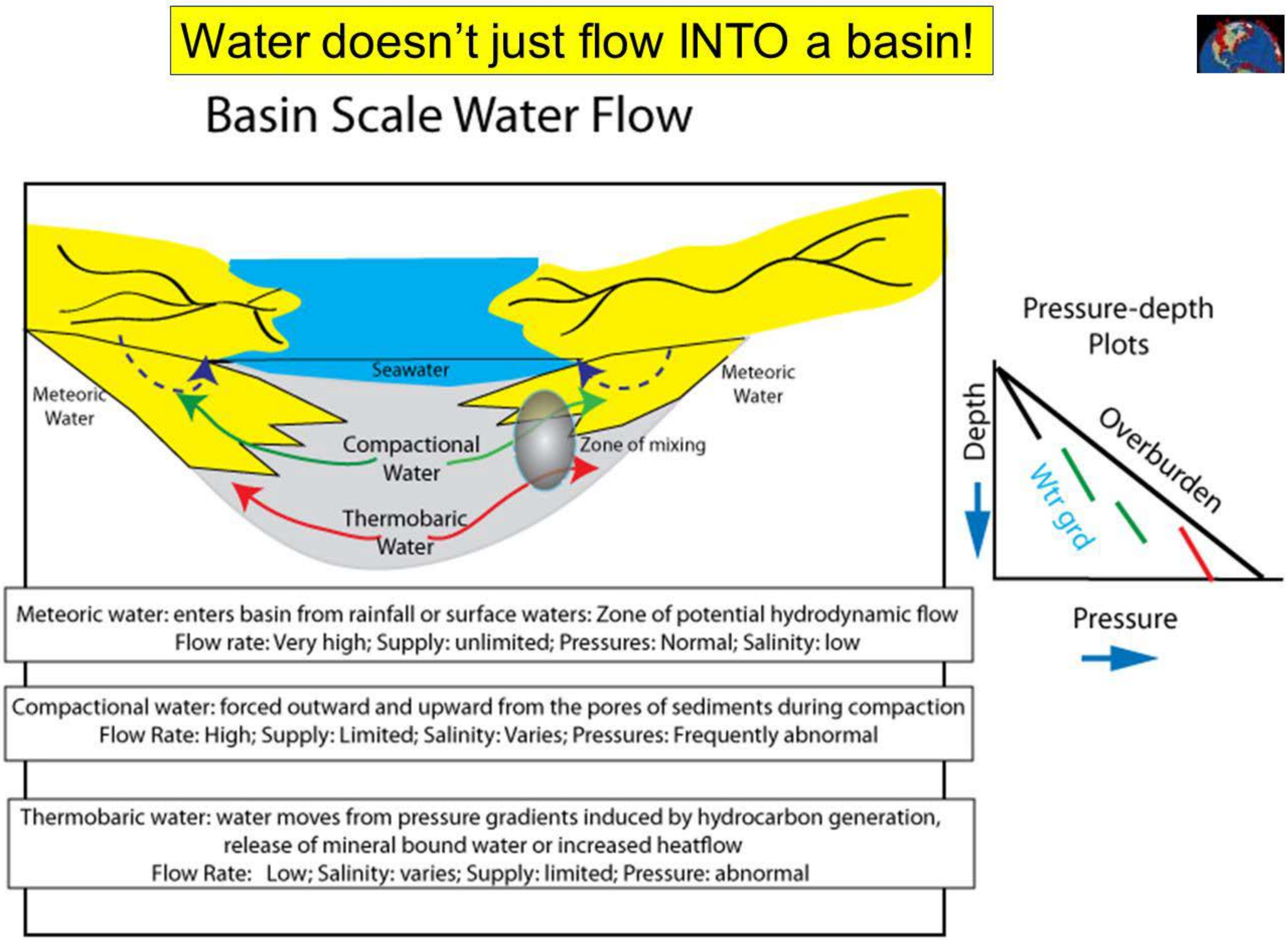


Figure 7. Three major types of water systems in a basin and direction of flow. From Dolson (2016), and modified from Hartmann and Beaumont (1999).

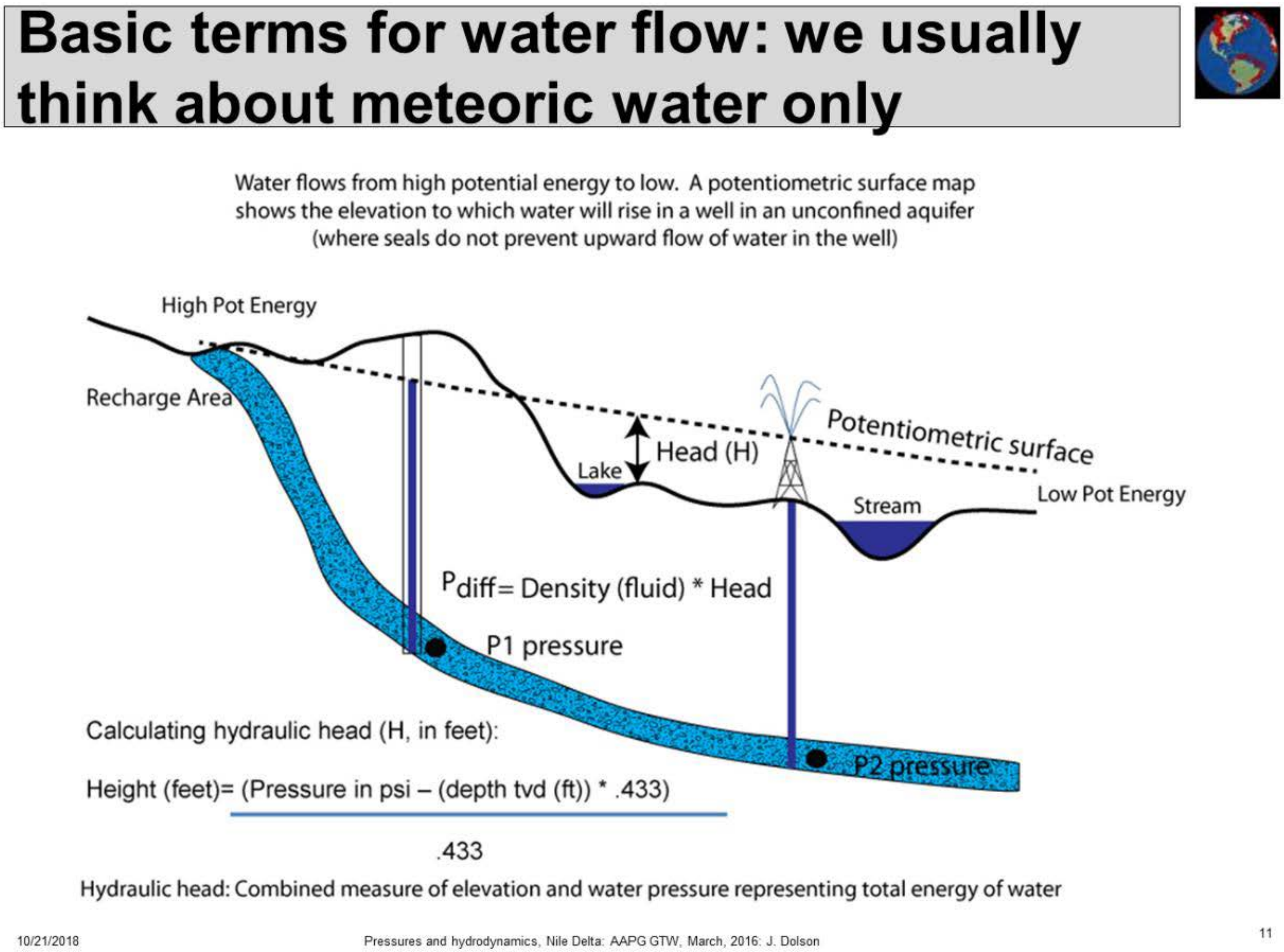
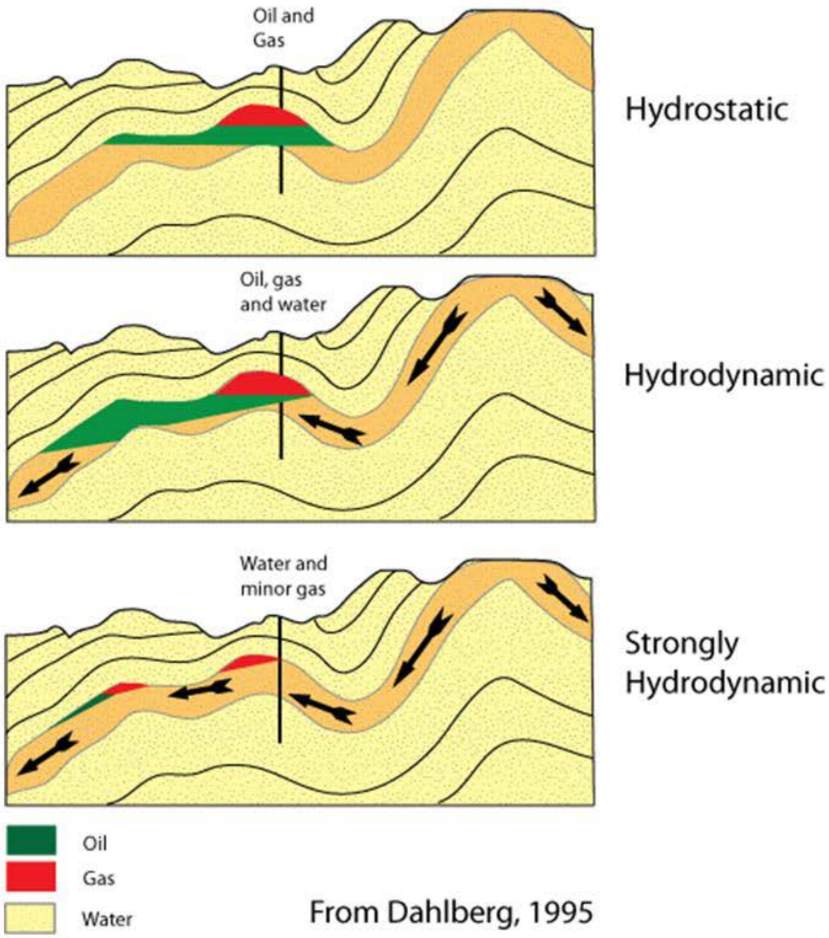


Figure 8. Hydraulic head. Water flow is a function of excess pressure and potential energy. Quantifying and mapping the potentiometric surface are key to understanding and predicting water levels and flow lines. Modified from DNR (2018).

‘Normal’ View of tilted hydrocarbon contacts: shallow trends on periphery of basins



OCCURS IN ACTIVE HYDRODYNAMIC REGIMES

Generally shallow depths

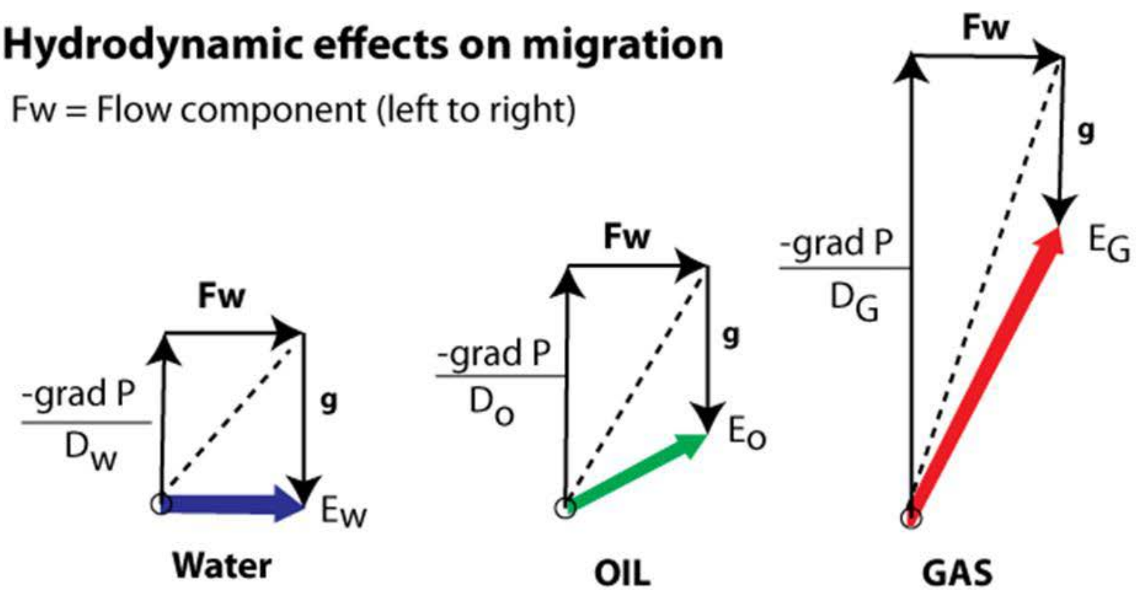
CAN BE DIFFICULT TO DISTINGUISH FROM CAPILLARY TRAPS

Attitude of the tilt is normal to the individual force vectors

Figure 9. Hydrodynamic tilt occurs when different fluid phases of oil and gas are encountered along a migration path in a hydrodynamic system.

Hydrodynamic effects on migration

Fw = Flow component (left to right)



Fw = Horizontal water vector

g= downward effect of gravity

D_W Density of water

D_O Density of oil

D_G Density of gas

E_W Vector direction of water

E_O Vector direction of oil

E_G Vector direction of gas

-grad P= negative of pressure gradient (pressure decreases upward)

Gas, with greater buoyancy, deflects the most in a hydrodynamic environment.

Hydraulic head maps must be converted to buoyancy for a hydrocarbon phase in order to be used in hydrodynamic tilt maps.

The U-V-Z approach utilizes these concepts to predict entrapment under hydrodynamic conditions.

In hydrostatic cases, the buoyancy for both oil and gas is vertical and hydraulic head and water flow is not an issue.

Modified from Dahlberg, E. C., 1995, Applied Hydrodynamics in Petroleum Exploration, 2nd Edition: New York, New York, Springer Verlag, 295 p.. Used with permission.

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Figure 10. A good diagram of the divergent motion of fluids under hydrodynamic conditions shows that the degree of tilt is a function of the density differences in the fluids involved. Modified from Dahlberg (1995).

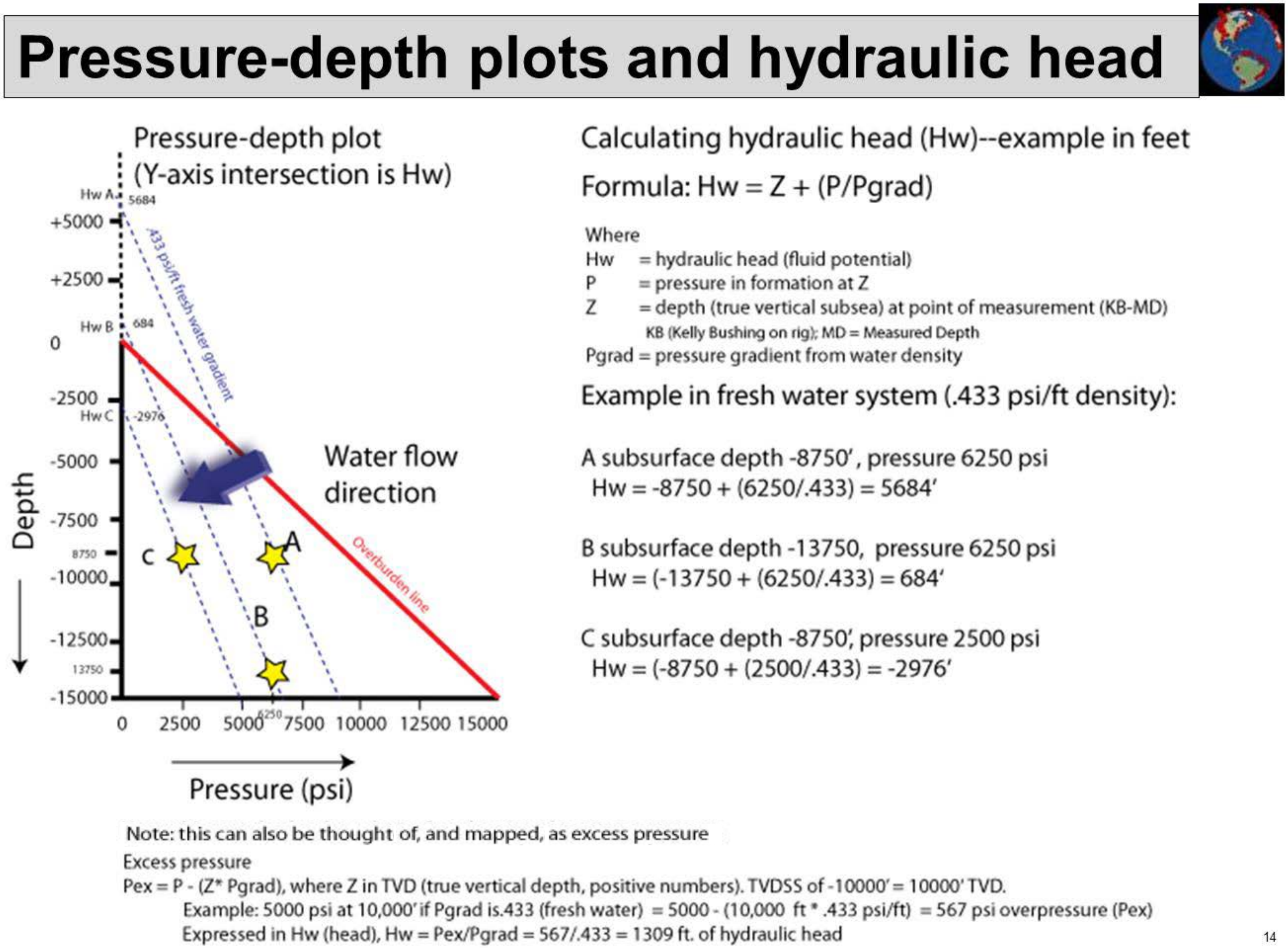


Figure 11. Pressure-depth plots can be used to estimate hydraulic head (the height to which water will rise in a well due to excess pressure. These kinds of plots can be used to access seals but also to recognize the direction of deep basin water flow (Dolson, 2016).

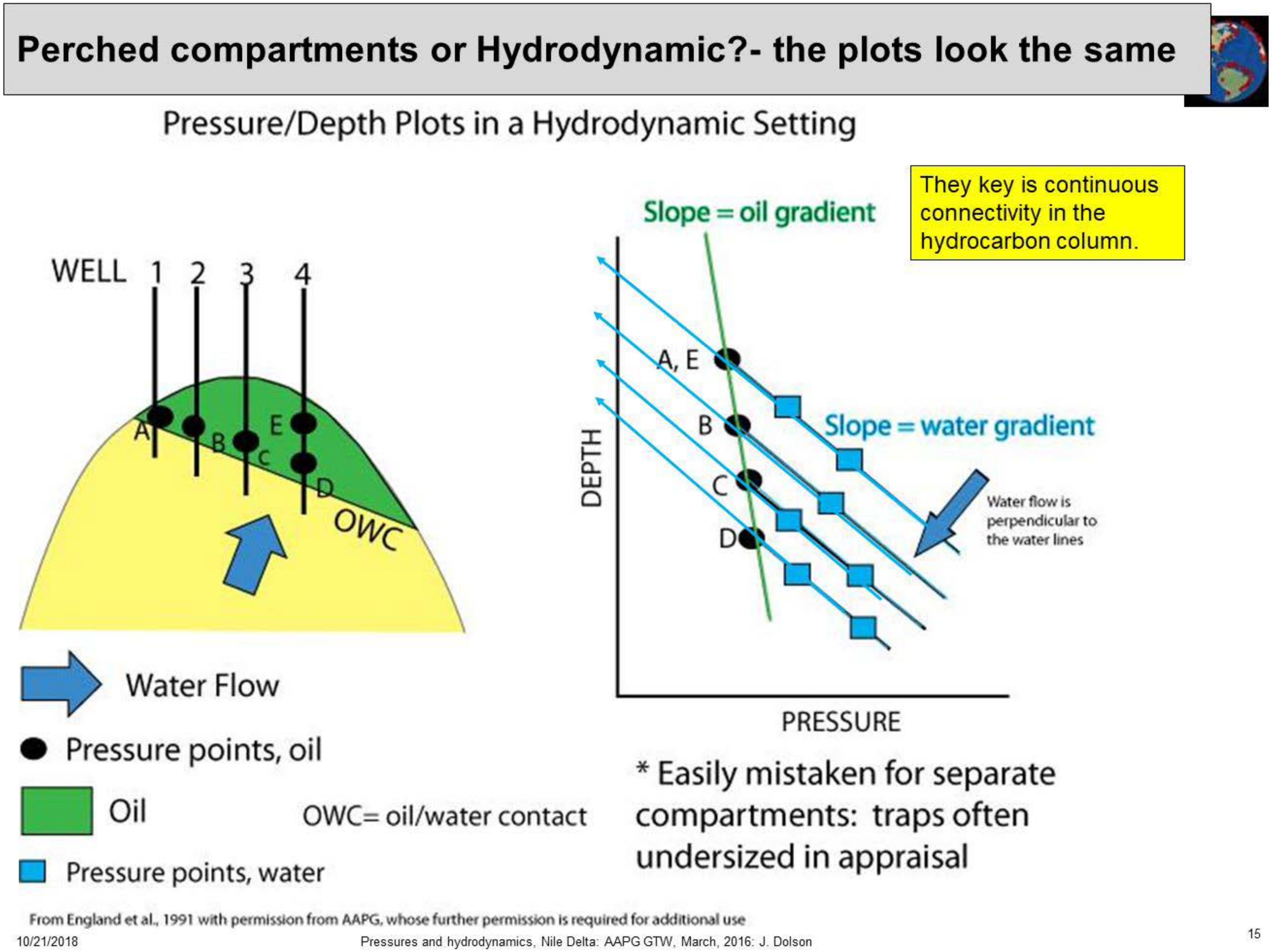


Figure 12. What a tilted contact looks like on a pressure/depth plot.

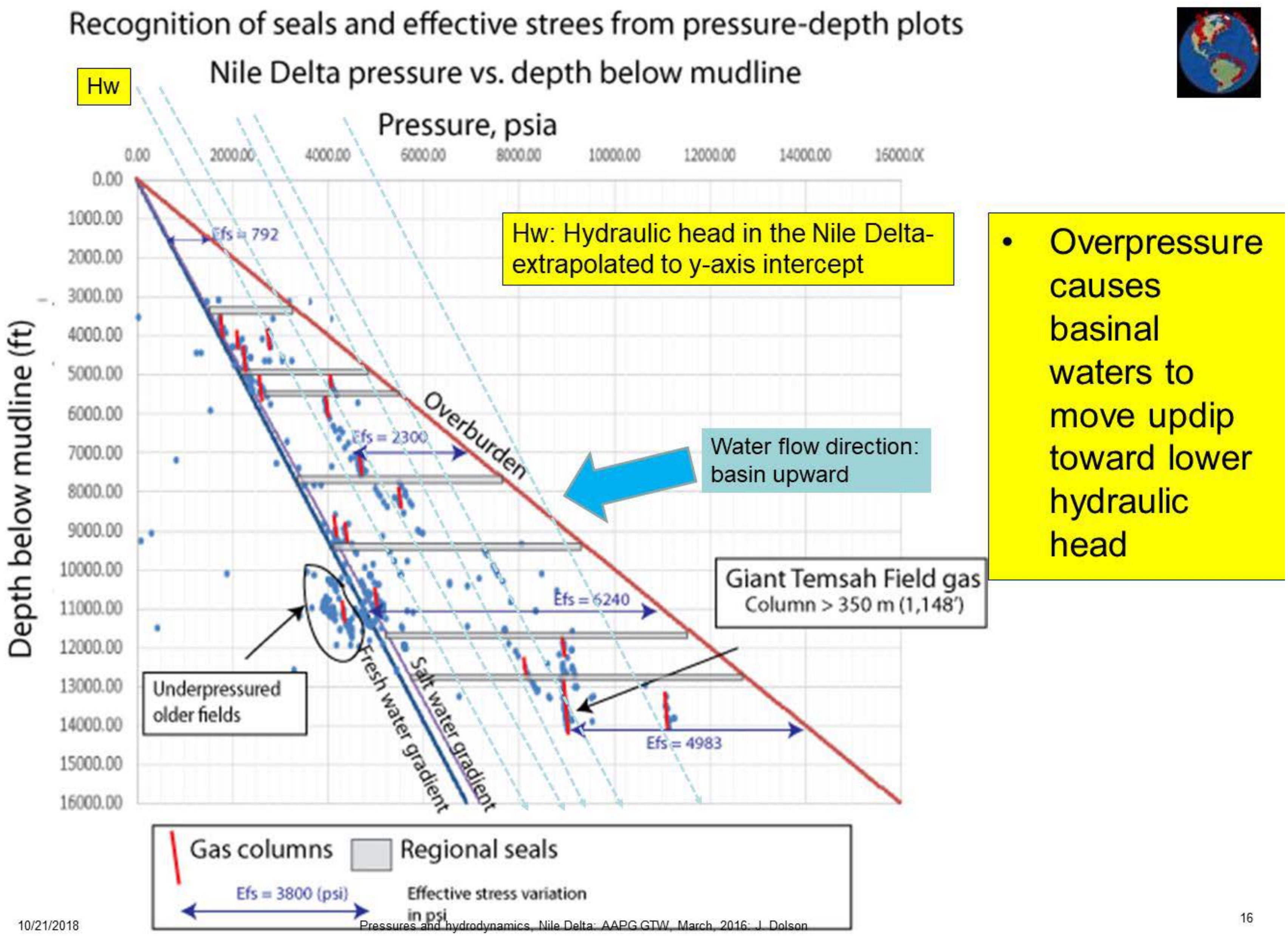


Figure 13. Nile Delta pressure vs. depth plot

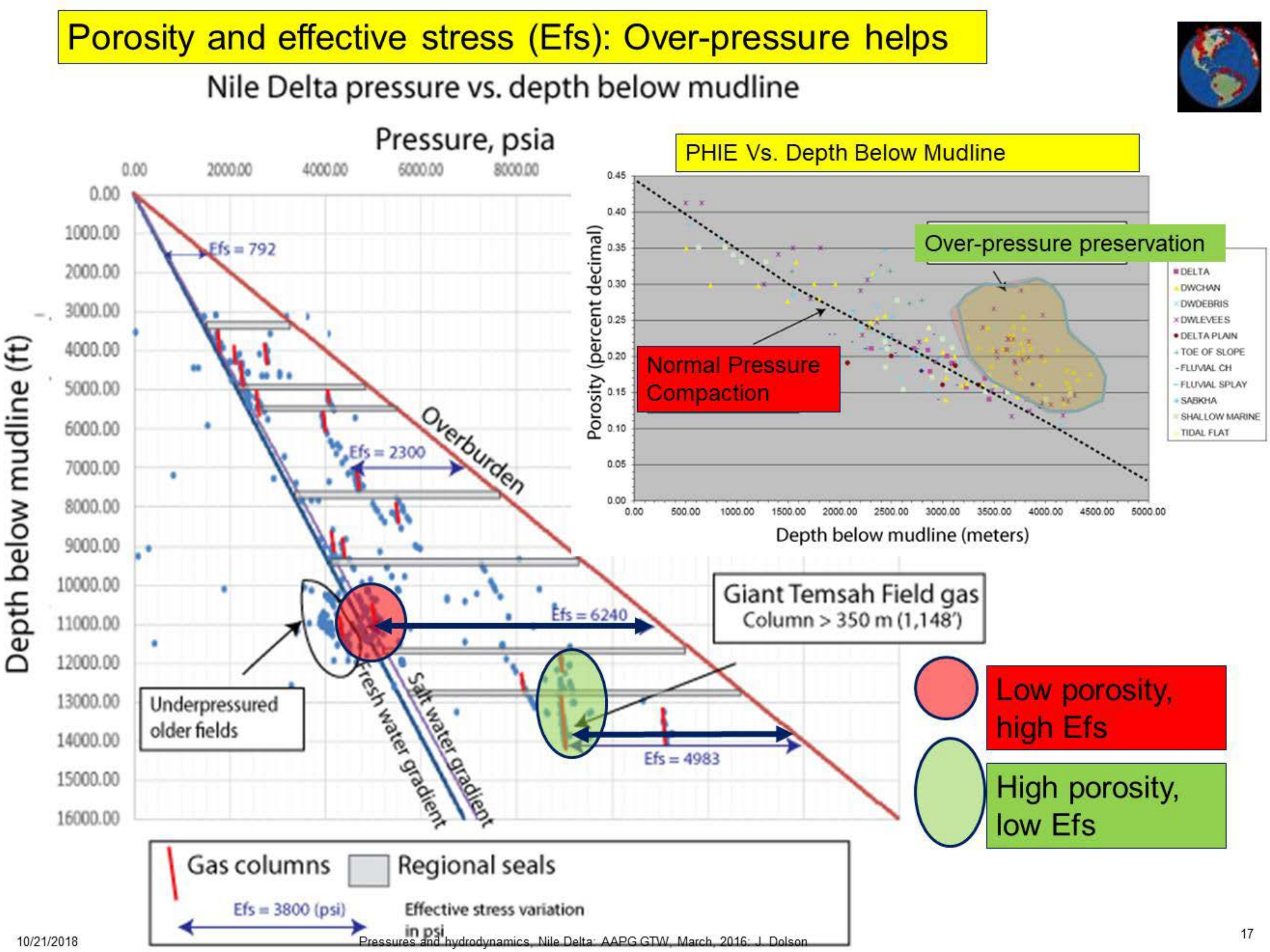


Figure 14. Porosity vs. effective stress.

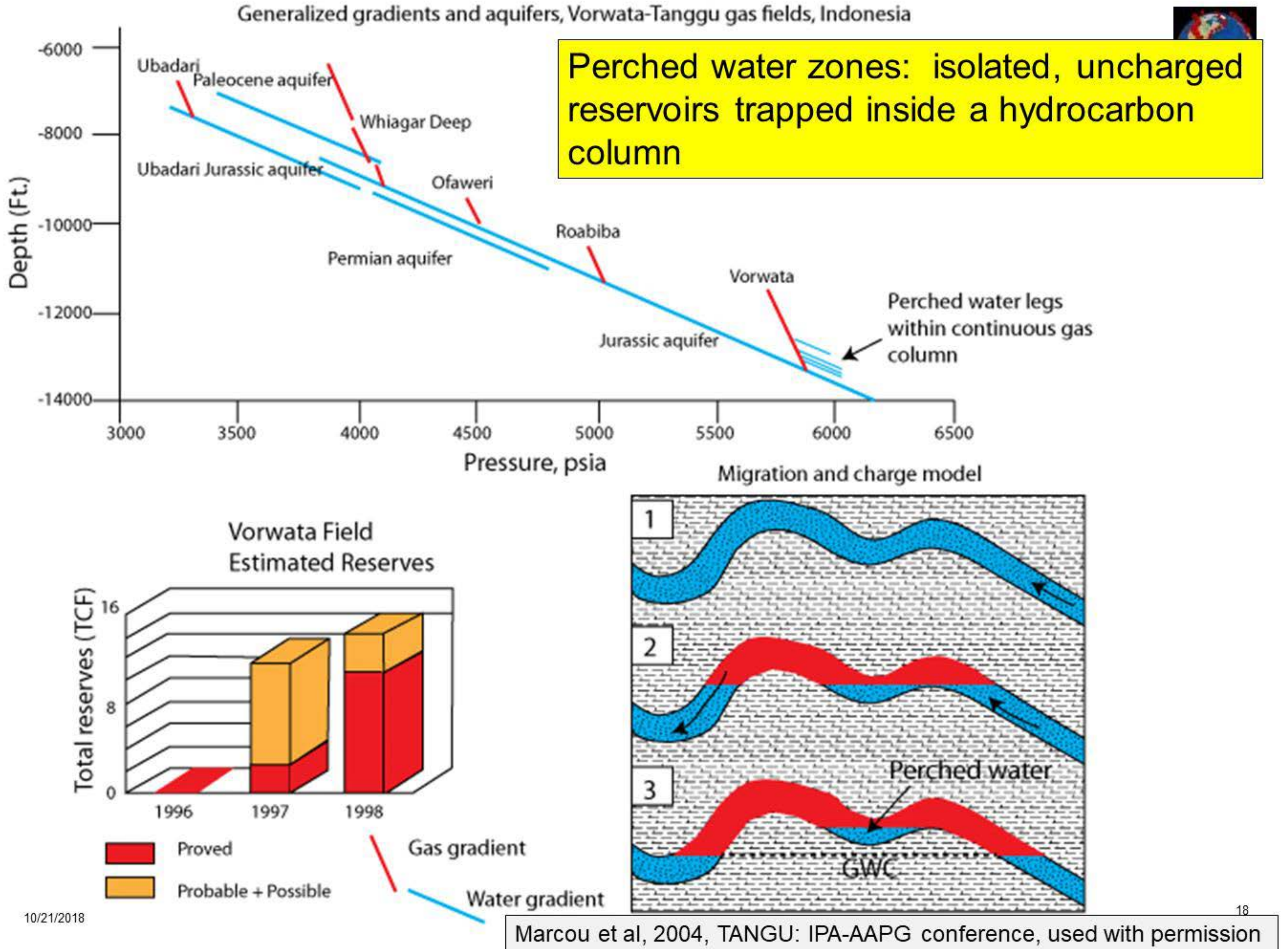


Figure 15. Perched water in Tangu Field, Indonesia. The pressure vs. depth plots look identical to other fields under tilting by hydrodynamic flow.

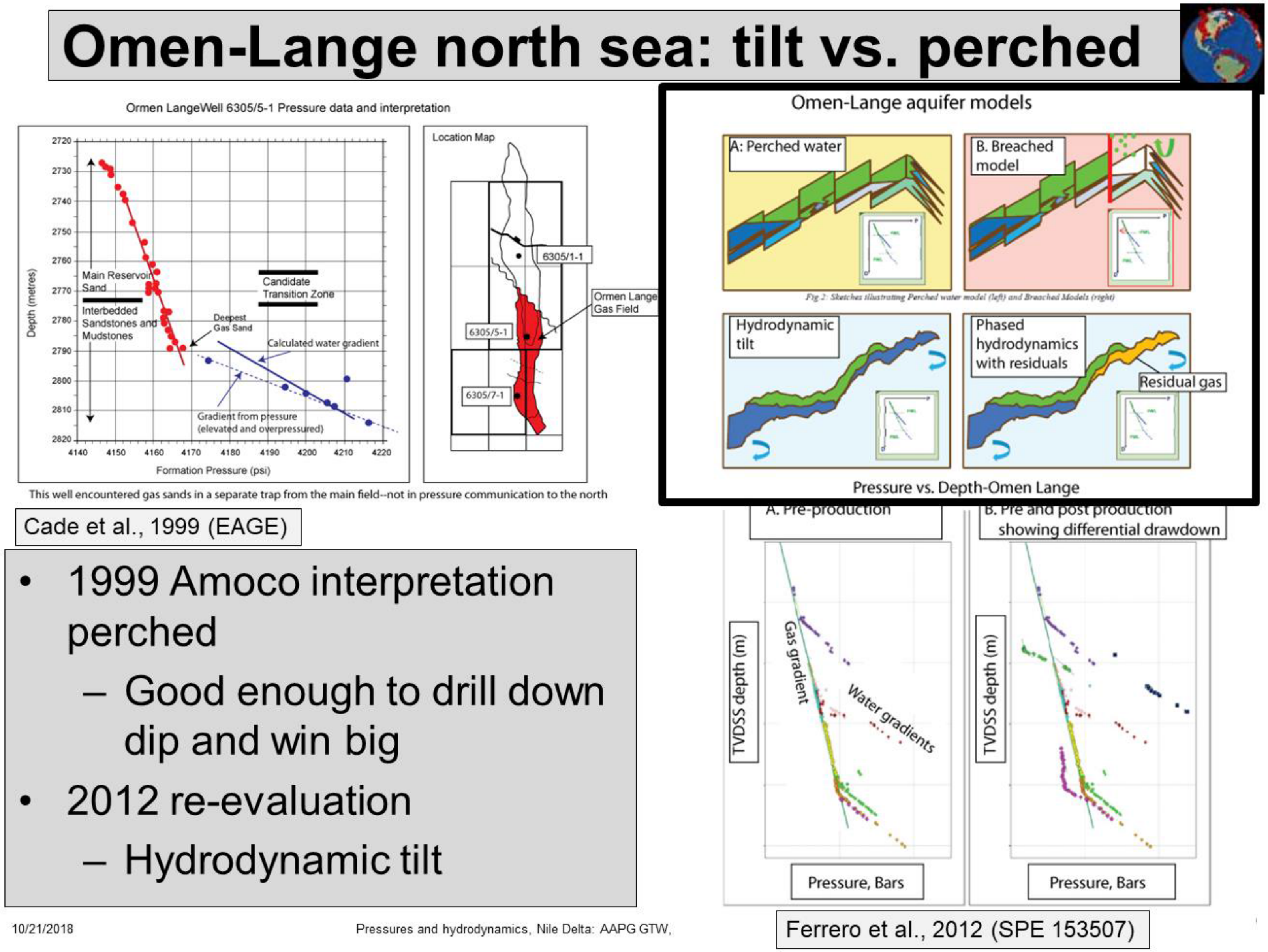


Figure 16. Well documented example of a change in concept from perched water to hydrodynamic tilt over time (Ferrero et al., 2012) vs. the perched interpretation made in 1999 (Cade et al., 1999).

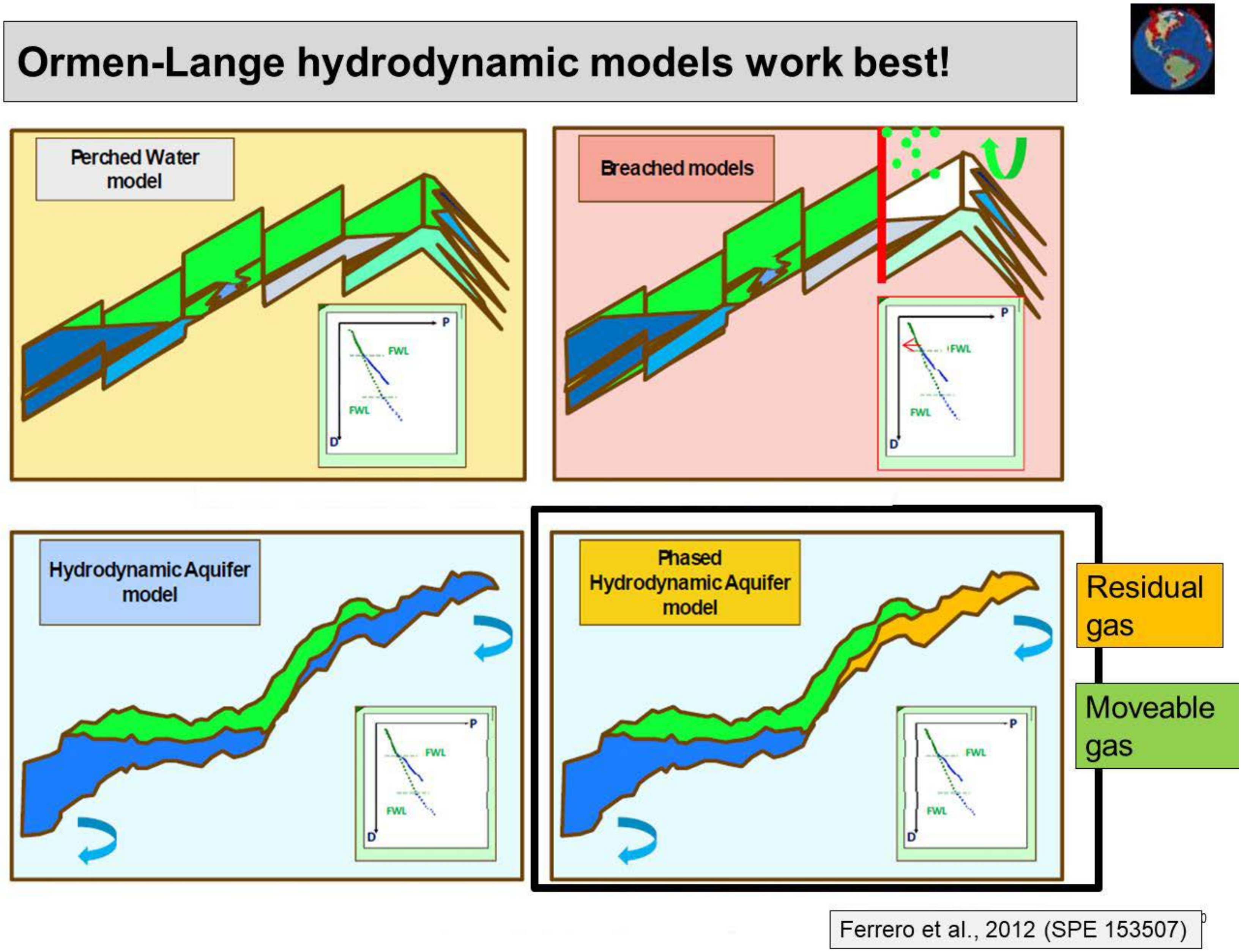
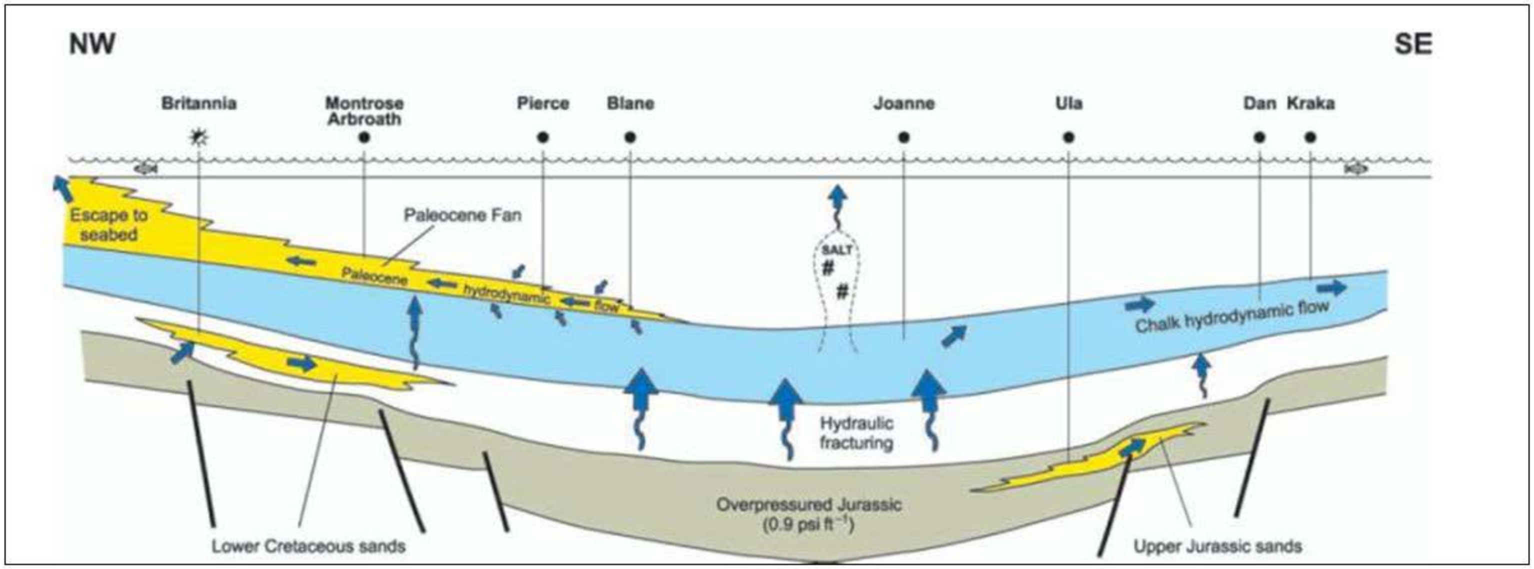
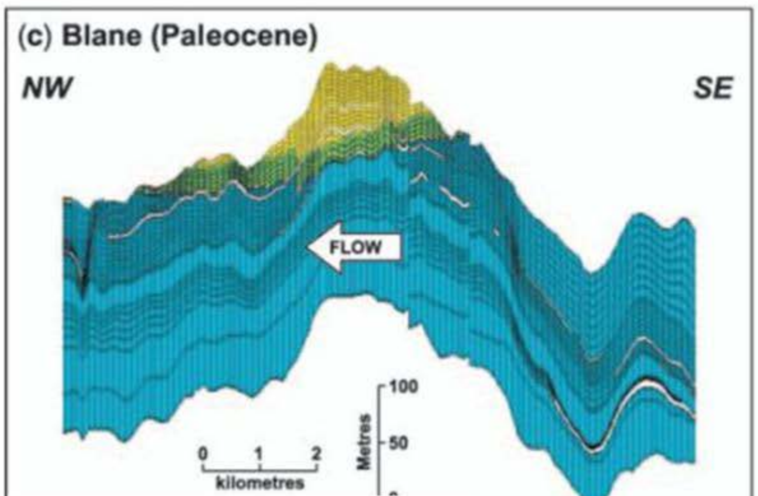
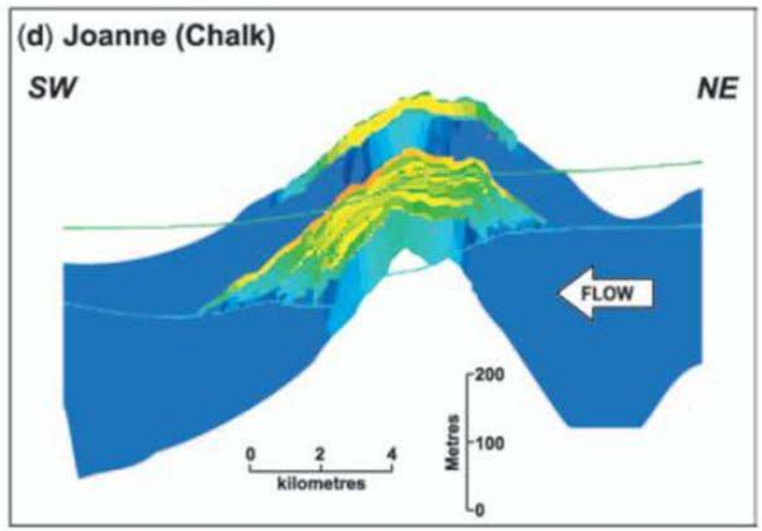


Figure 17. Perched vs. hydrodynamic and other models.

North Sea example of upward water flow and tilting







Tilted oil–water contacts: modelling the effects of aquifer heterogeneity
H. DENNIS, P. BERGMO and T. HOLT
Petroleum Geology Conference series 2005, v.6; p145-158.
doi: 10.1144/0060145

10/21/2018 ressures and hydrodynamics, Nile Delta: AAPG GTW, March, 2016: J. Dolson

Dennis, et al., 2005, Geolsoc

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Figure 18. Additional example of deep basin water flow and tilting, North Sea (Dennis et al., 2005)

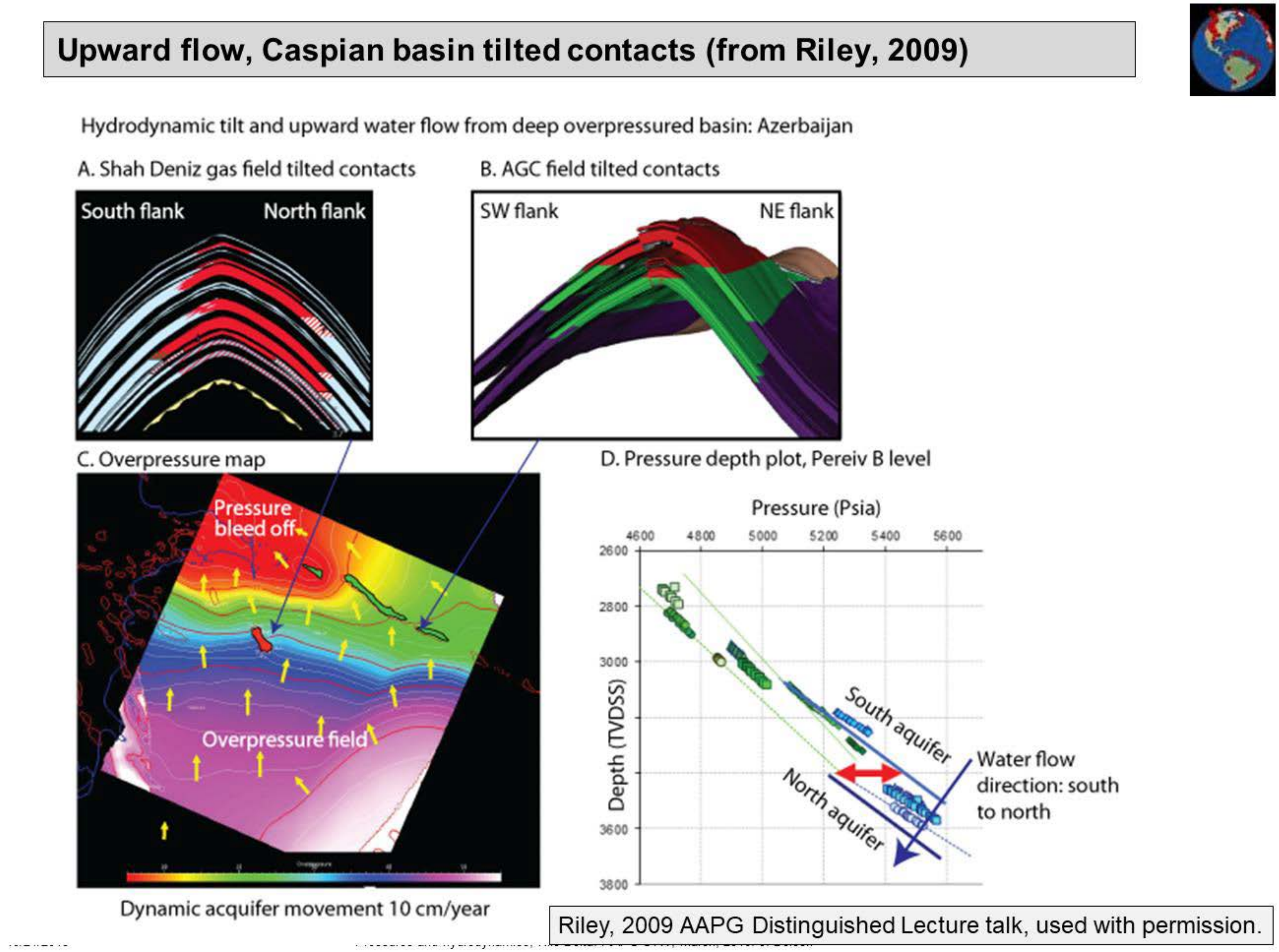


Figure 19. Upward basin flow and tilting, Caspian Basin (Riley, 2009).

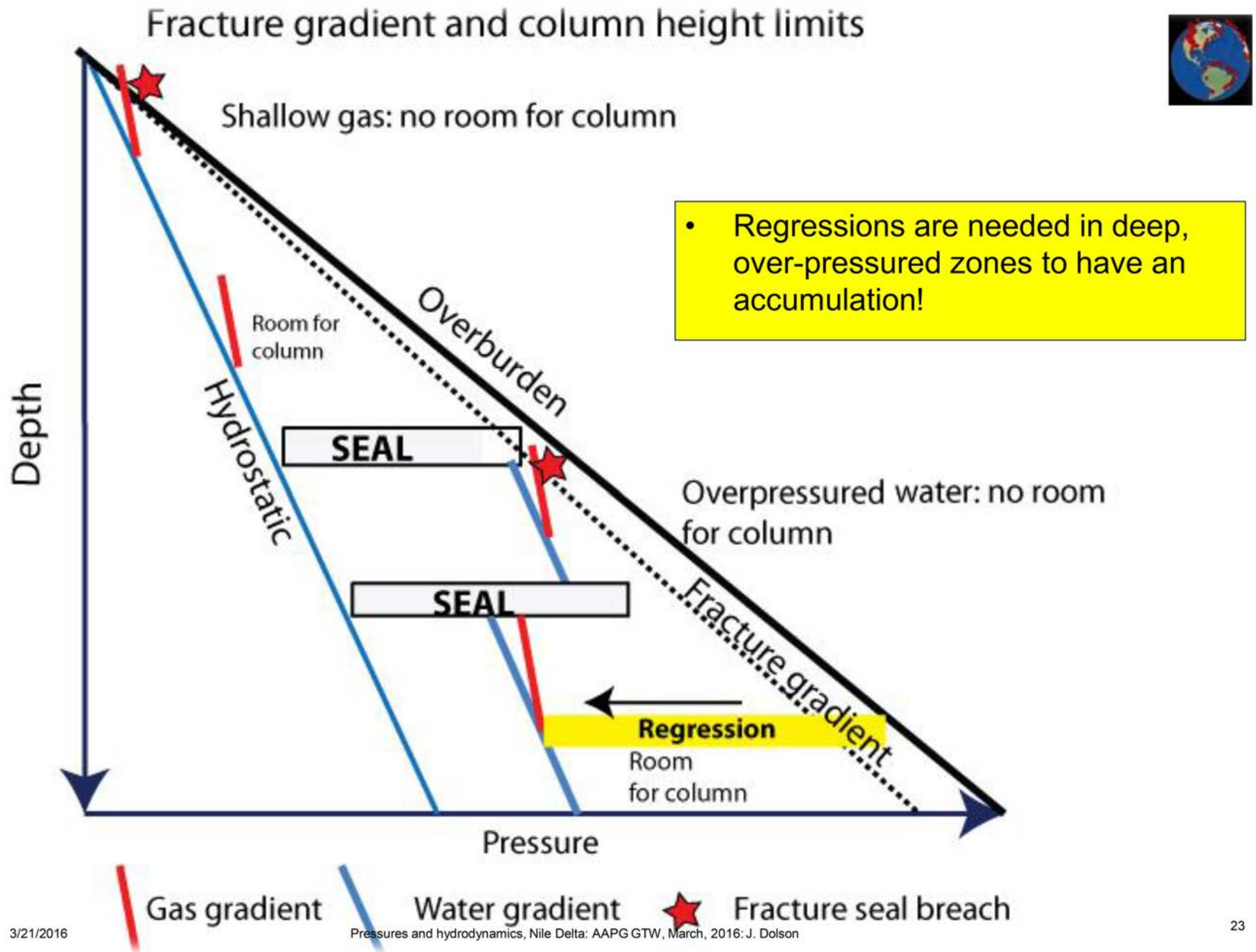


Figure 20. Simplified concept of a pressure regression (from Dolson, 2016).

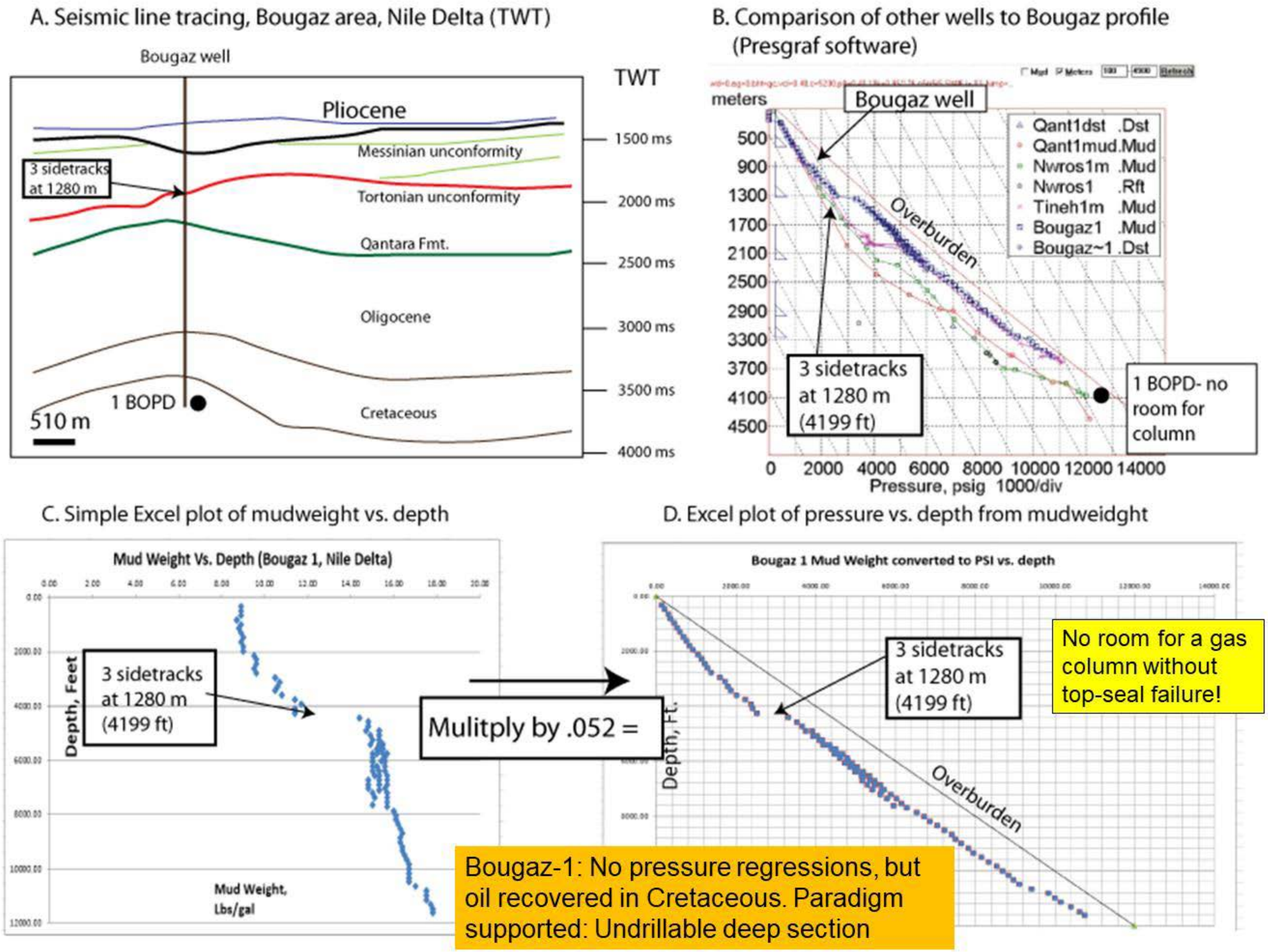


Figure 21. Trap and seal failure, Bougaz well, Nile Delta. No pressure regression occurred in this well and the result is a dry 4-way structural closure where high pore pressure prevented a tall column from being developed.

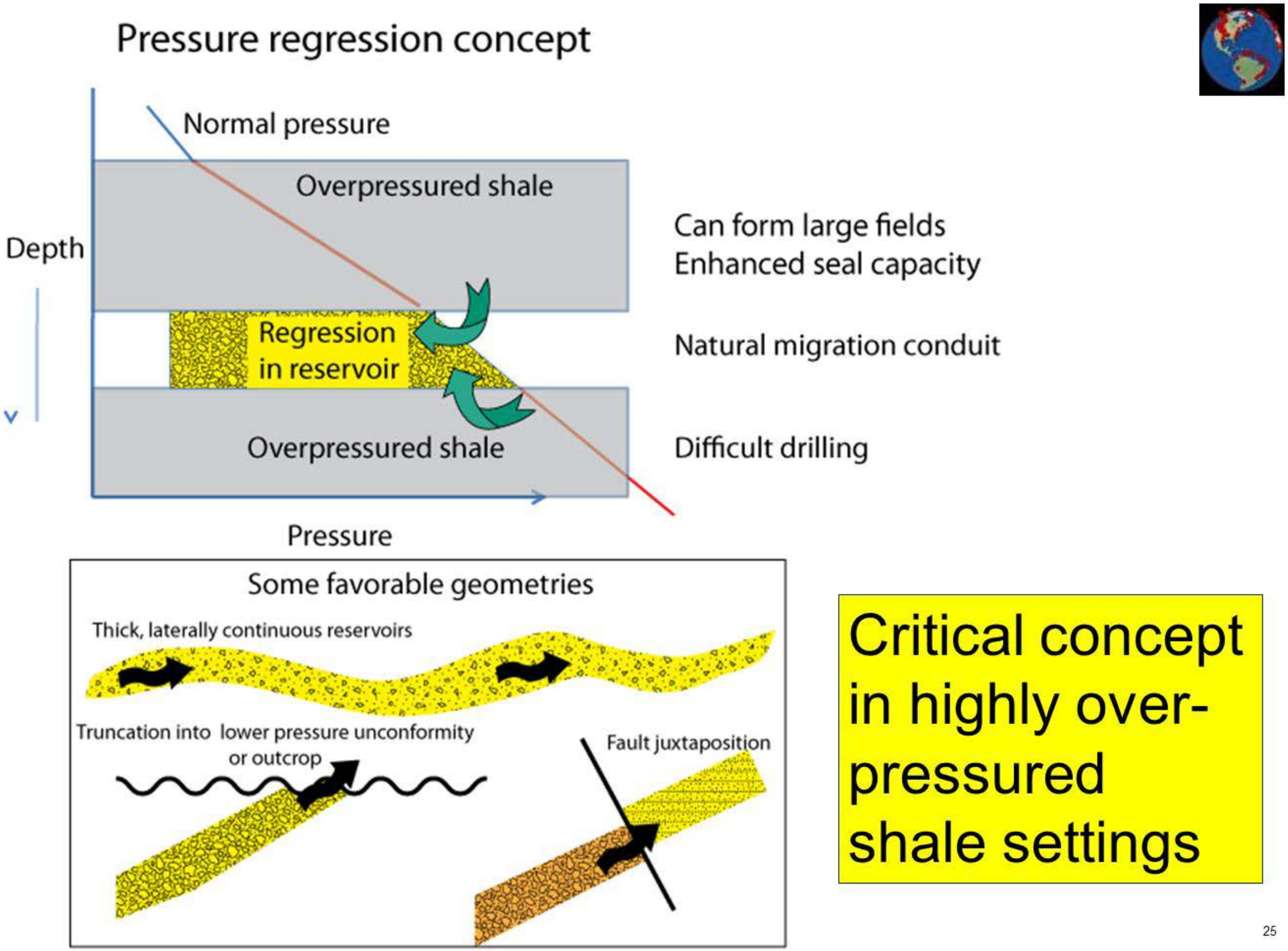


Figure 22. Favorable geometries for regressions.

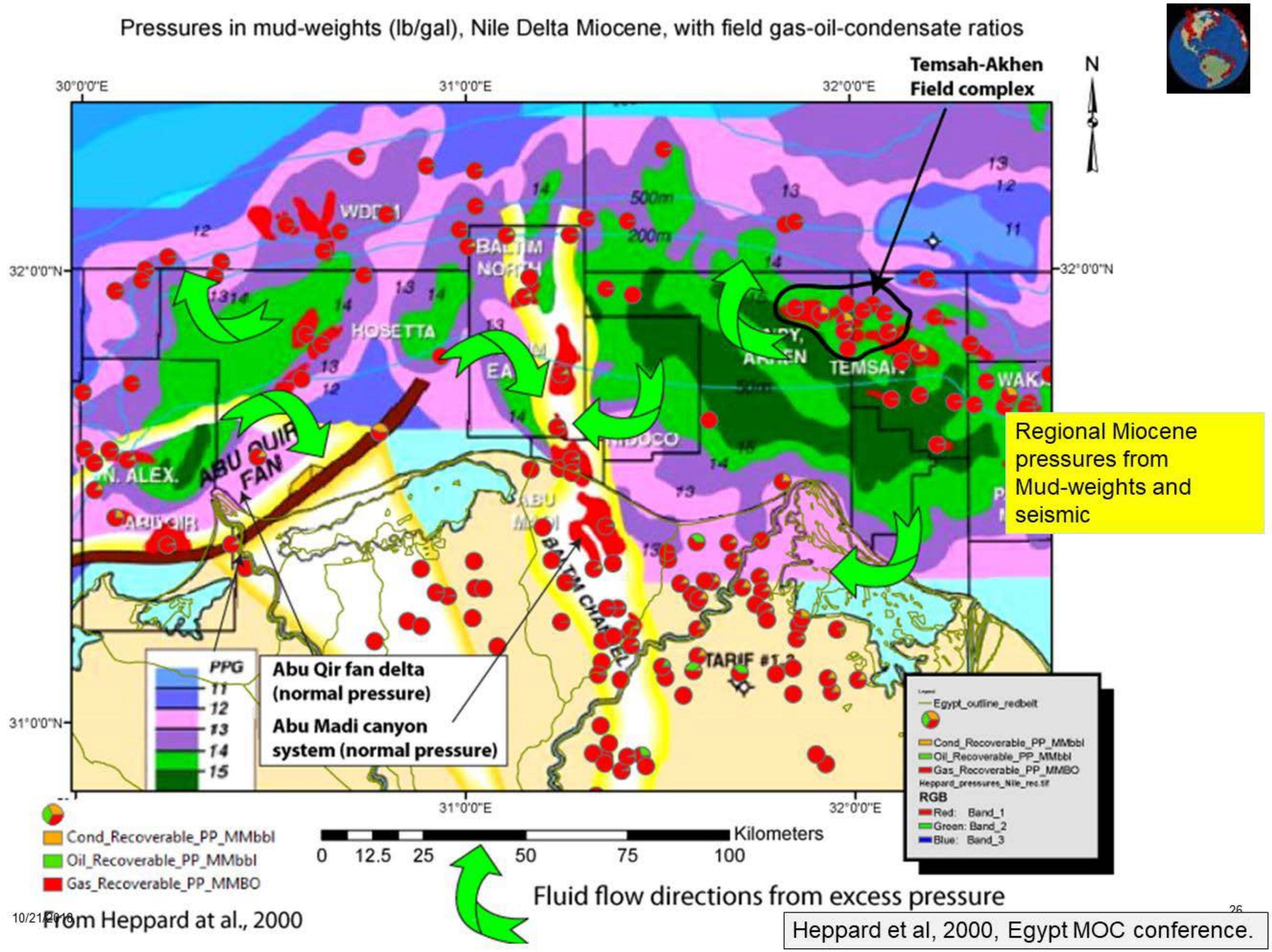


Figure 23. Nile Delta Miocene pressure system.

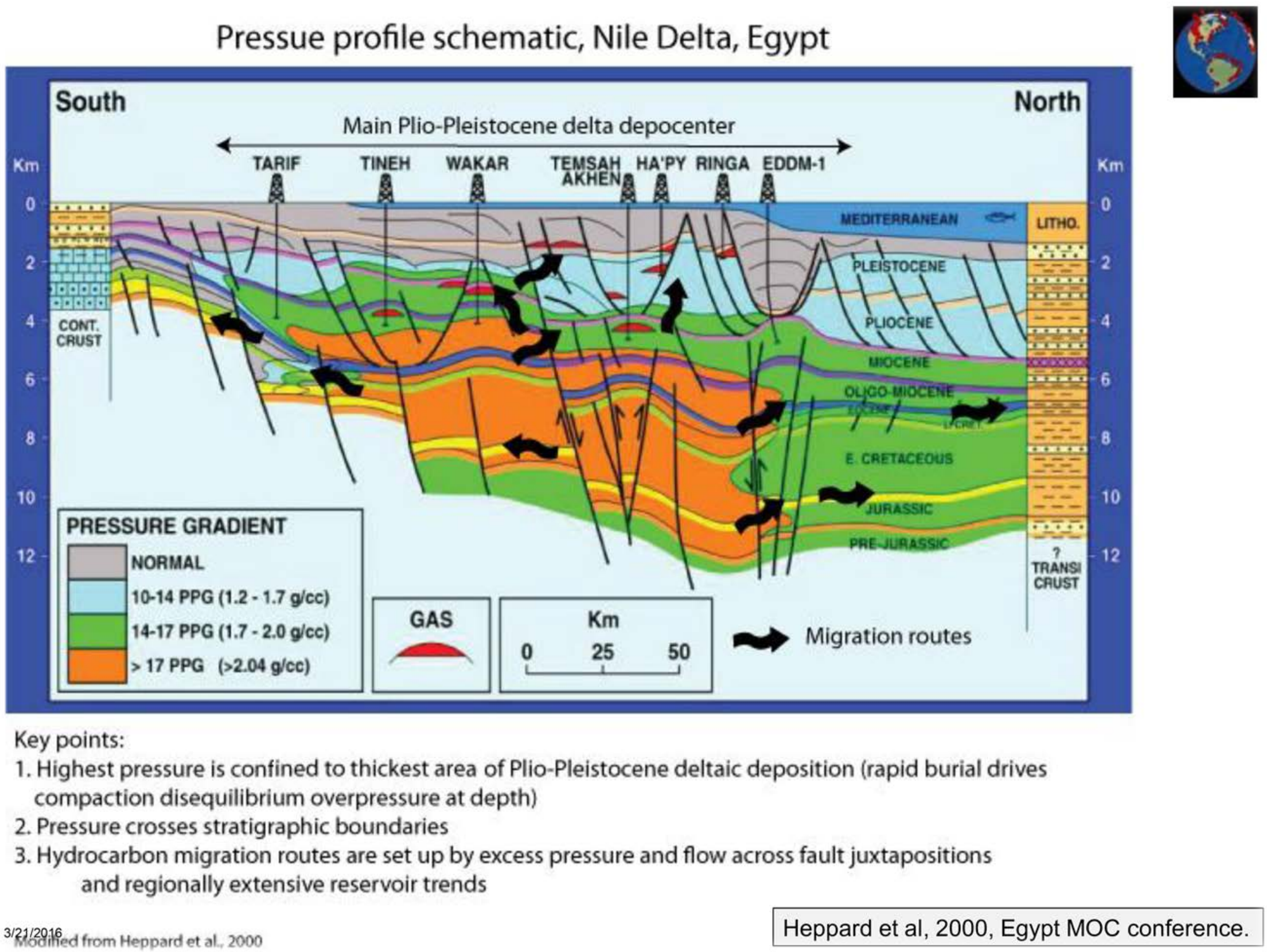


Figure 24. Cross-sectional cartoon of Nile Delta pressures and migration pathways. Modified from Heppard et al. (2000).

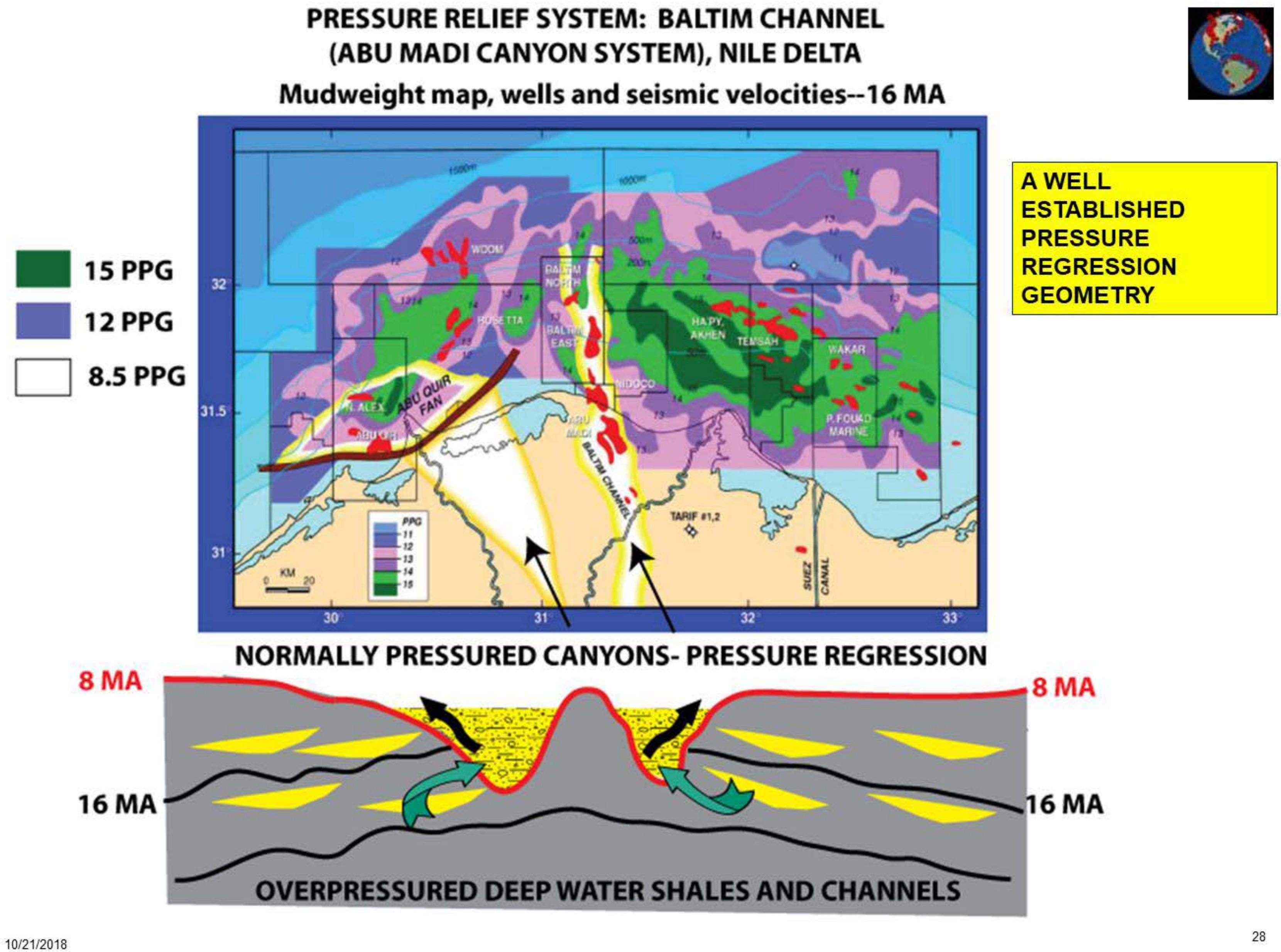


Figure 25. Schematic of the Abu Madi Canyon system pressure regression.

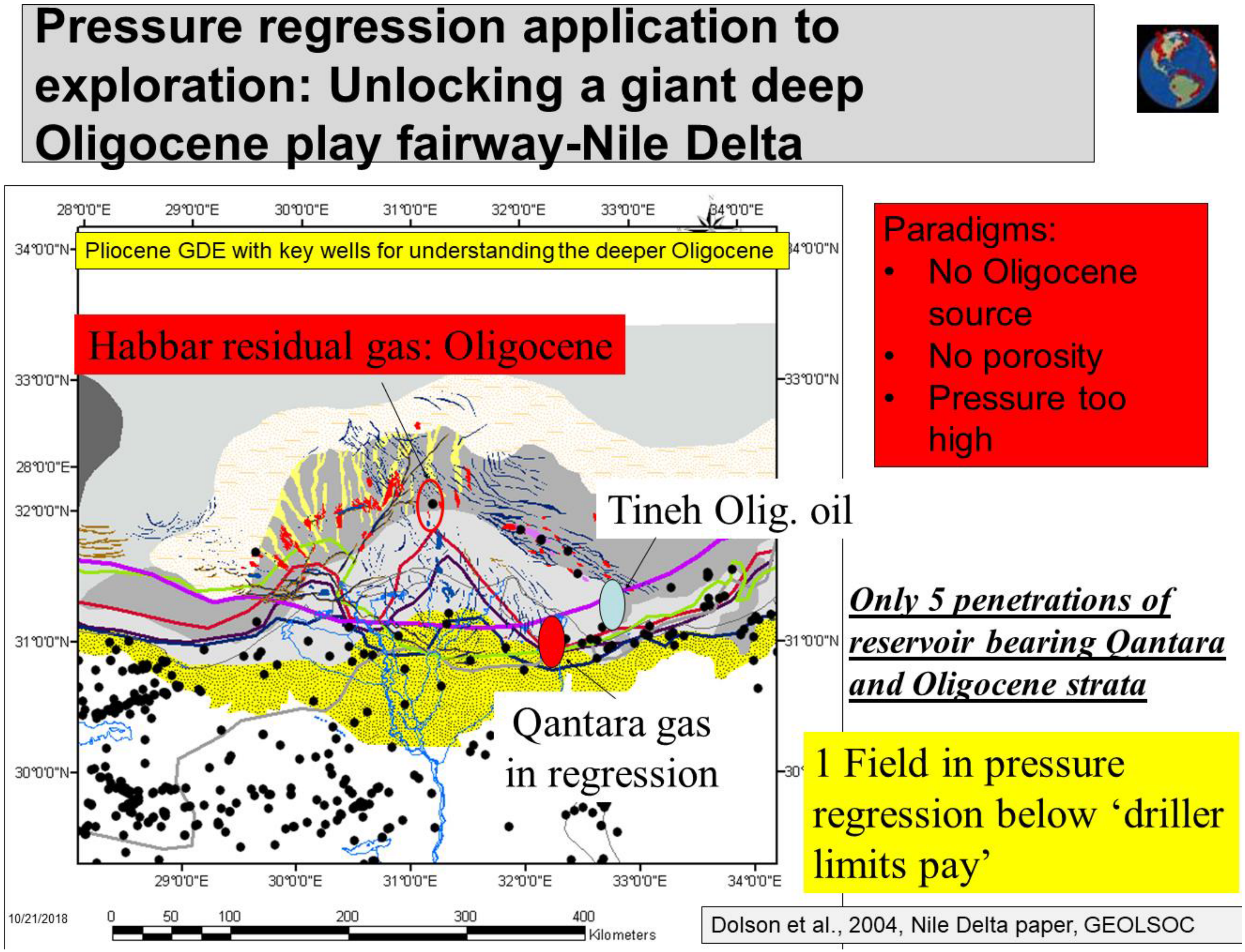


Figure 26. Miocene GDE and key wells used to derisk the Satis Field and other deeper plays near the Abu Madi canyon pressure regression.

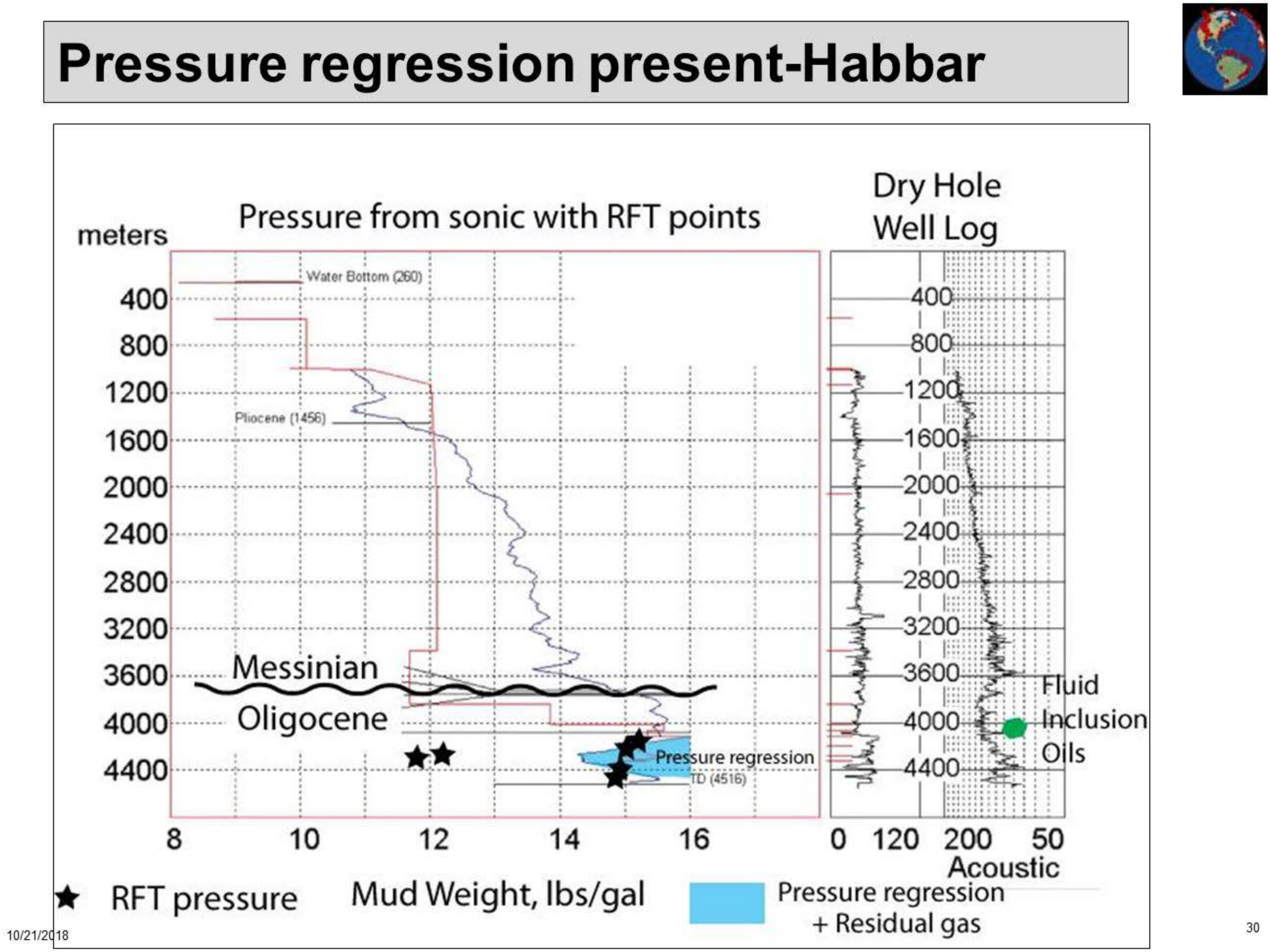


Figure 27. Pressures and logs, Habbar well. A pronounced pressure regression in a zone of residual gas showed migration through this trap. Fluid inclusion data showed oil as well as gas in the system.

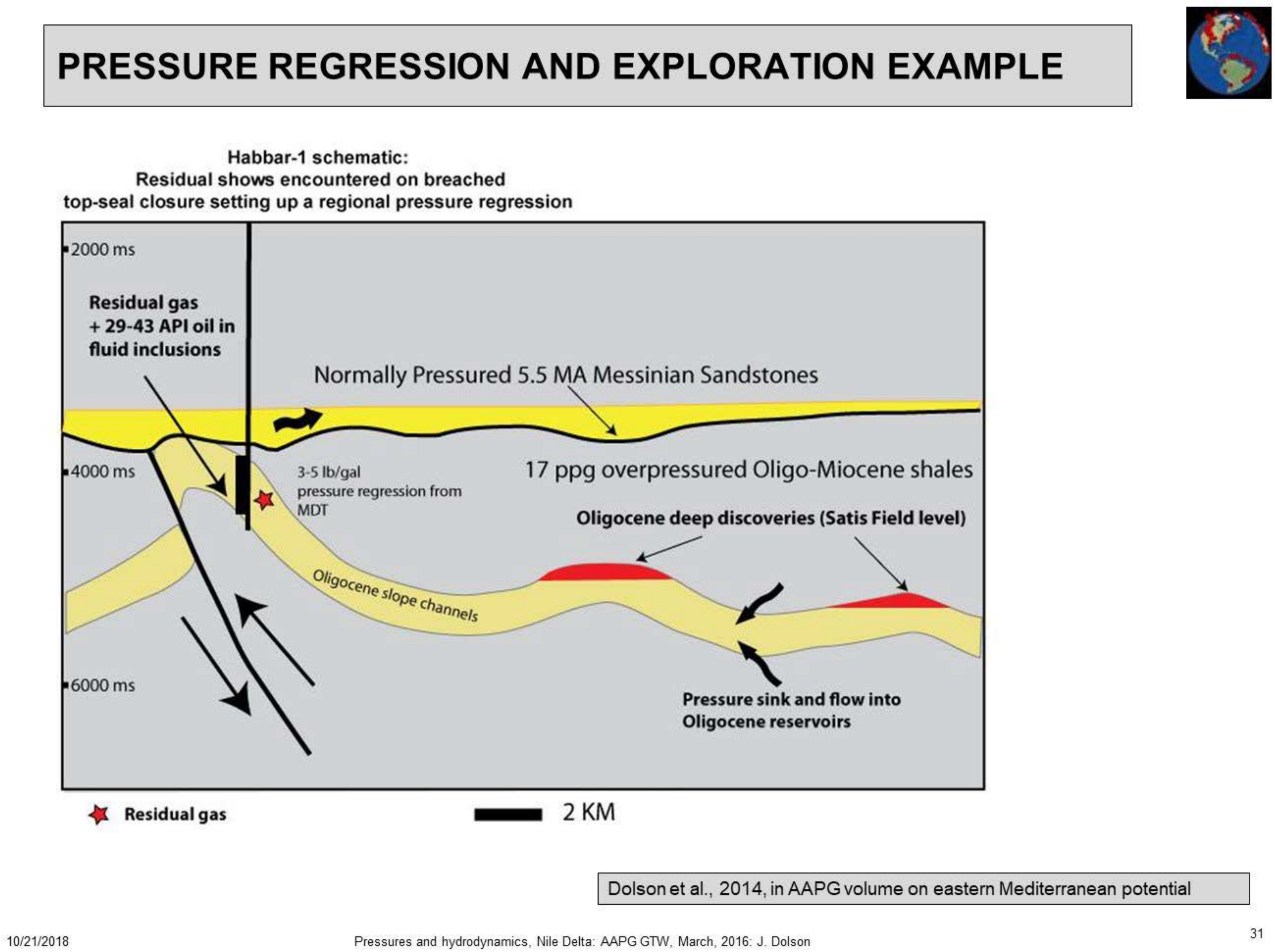


Figure 28. Challenging a paradigm with recognition of the cause of the Habbar-1 failure as a result of seal breach into the Messinian unconformity (Dolson, 2016).

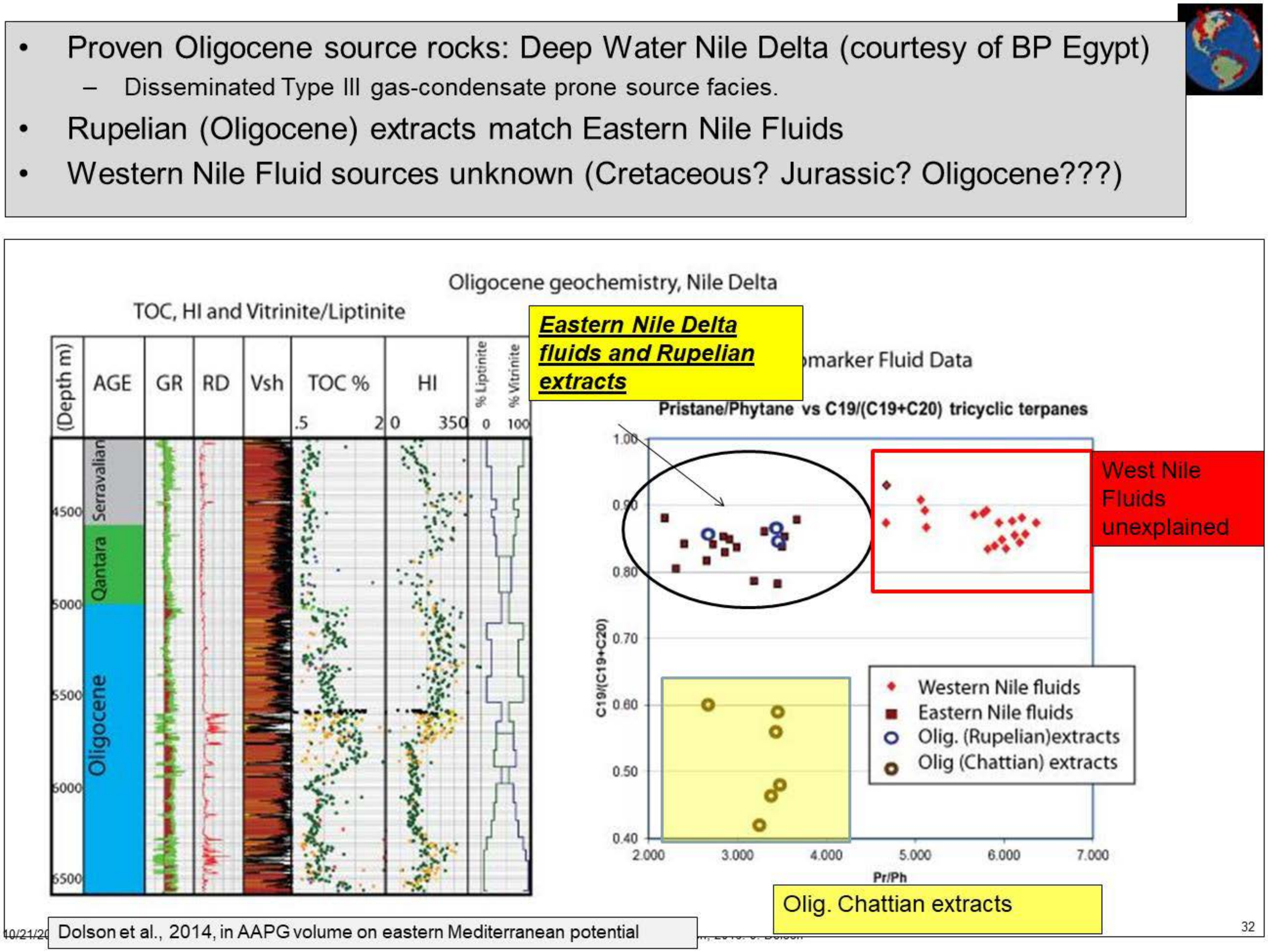


Figure 29. Geochemistry in the deep Satis well confirms a deeper Oligocene source rock.

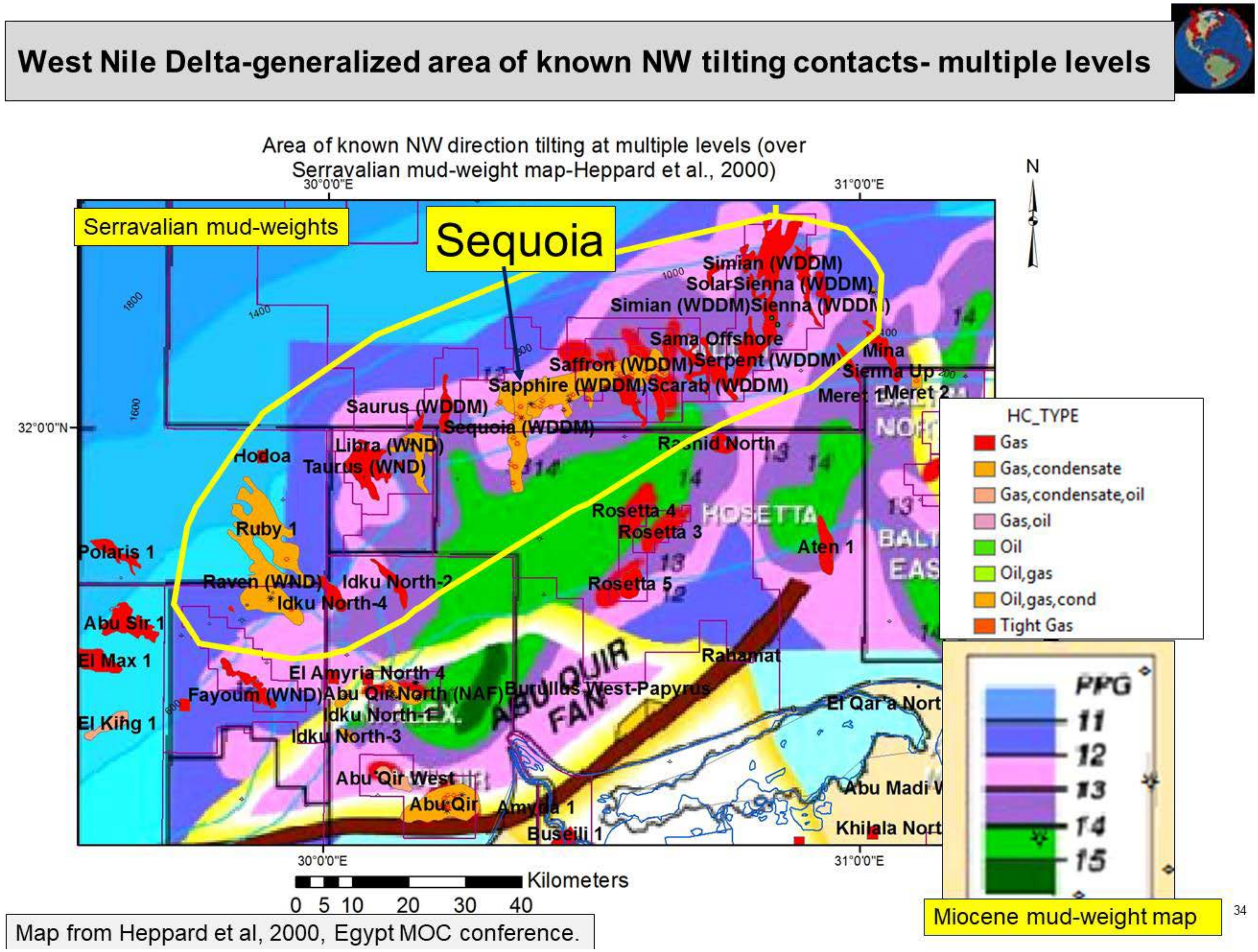


Figure 30. Pliocene-Pleistocene fields of the Sequoia complex overlying deep, over-pressured Miocene shales.

Nile Delta Pliocene: perched water in channel synclinal lows or tilted?

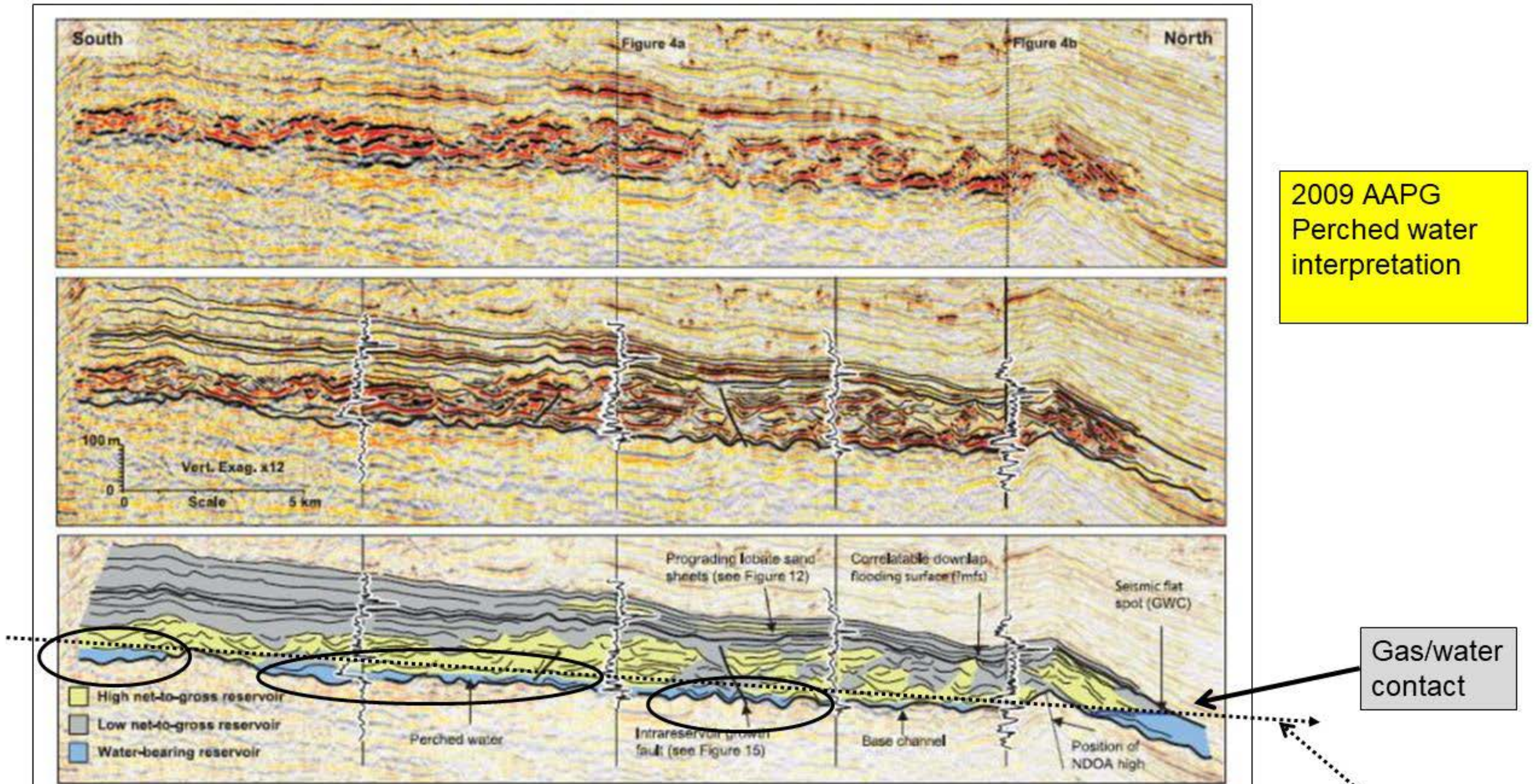


Figure 3. North–south, seismic cross section and interpretation from along the length (downdip) of the Sequoia field illustrating an upward-fining profile of channelized high net-to-gross (bright amplitude) and low net-to-gross (dull amplitude) reservoir facies. The location of the downdip aquifer (GWC = gas-water contact) and areas of perched water are also shown. The location of this cross section, which is depicted on Figure 2, coincides with the position of the four exploration and appraisal wells that also display simplified gamma-ray log profiles. The base of the channel system is defined by a prominent erosion surface, whereas above it is buried by a series of prograding and downlapping slope deposits. NDOA = Nile Delta offshore anticline; mfs = maximum flooding surface.

Or is it tilted? Difficult at times to tell!

From Cross et al, 2009, by permission of AAPG whose further permission is required for further use

AAPG BULLETIN, V. 93, NO. 8 (AUGUST 2009), PP. 1063–1086

Figure 31. Perched or tilted contacts? An alternative interpretation for the Sequoia Field area. Modified from Cross et al. (2009).

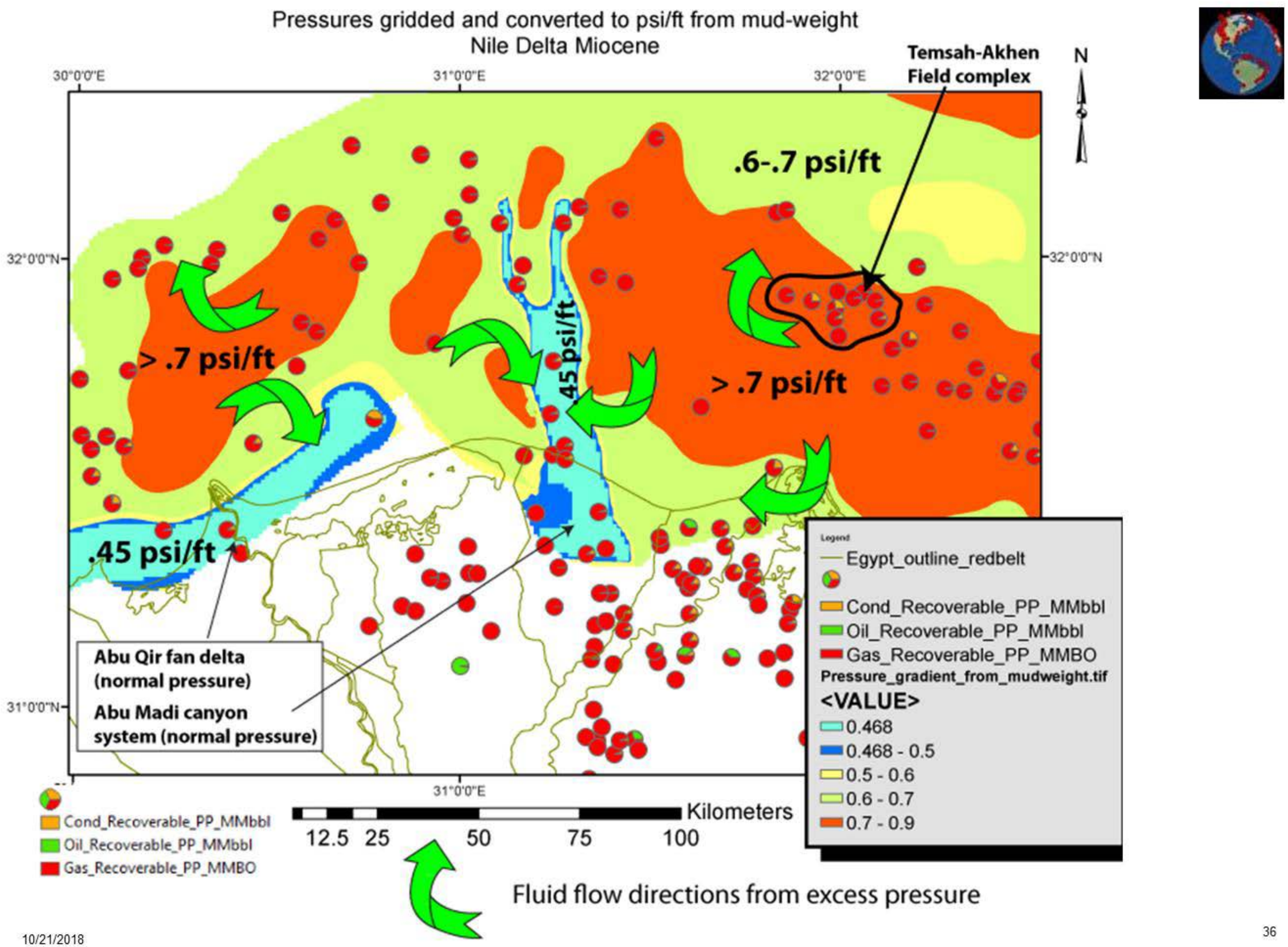
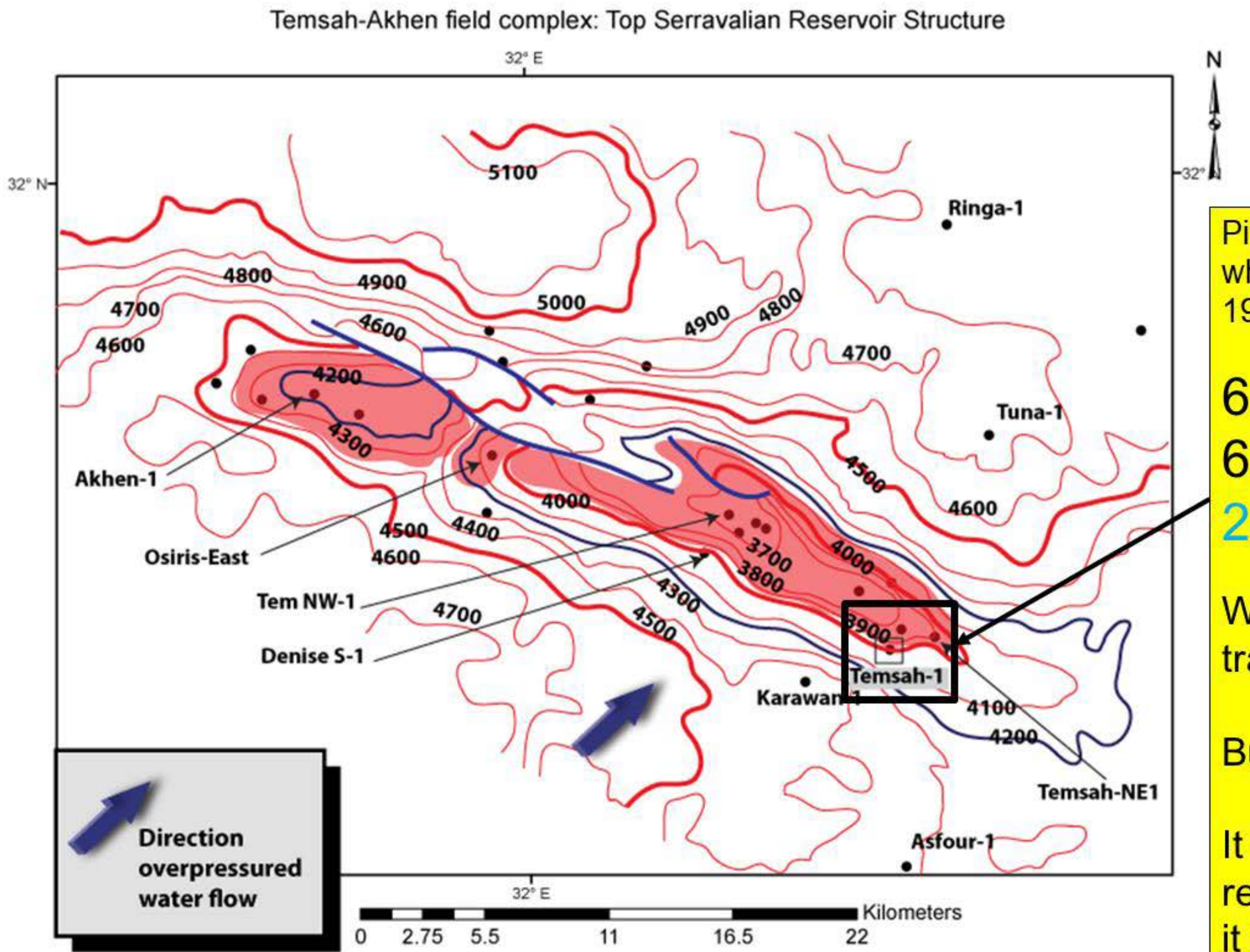


Figure 32. Conversion of the regional mud-weight map to pressure in psi/ft.

Generalized structure and gas accumulations, Temsah Field



Pity the poor geologist who drilled Temsah-1 in 1977.

6.4 MMCFD, 62.4 BOPD, 2730 BWPD

Water high on the trap!

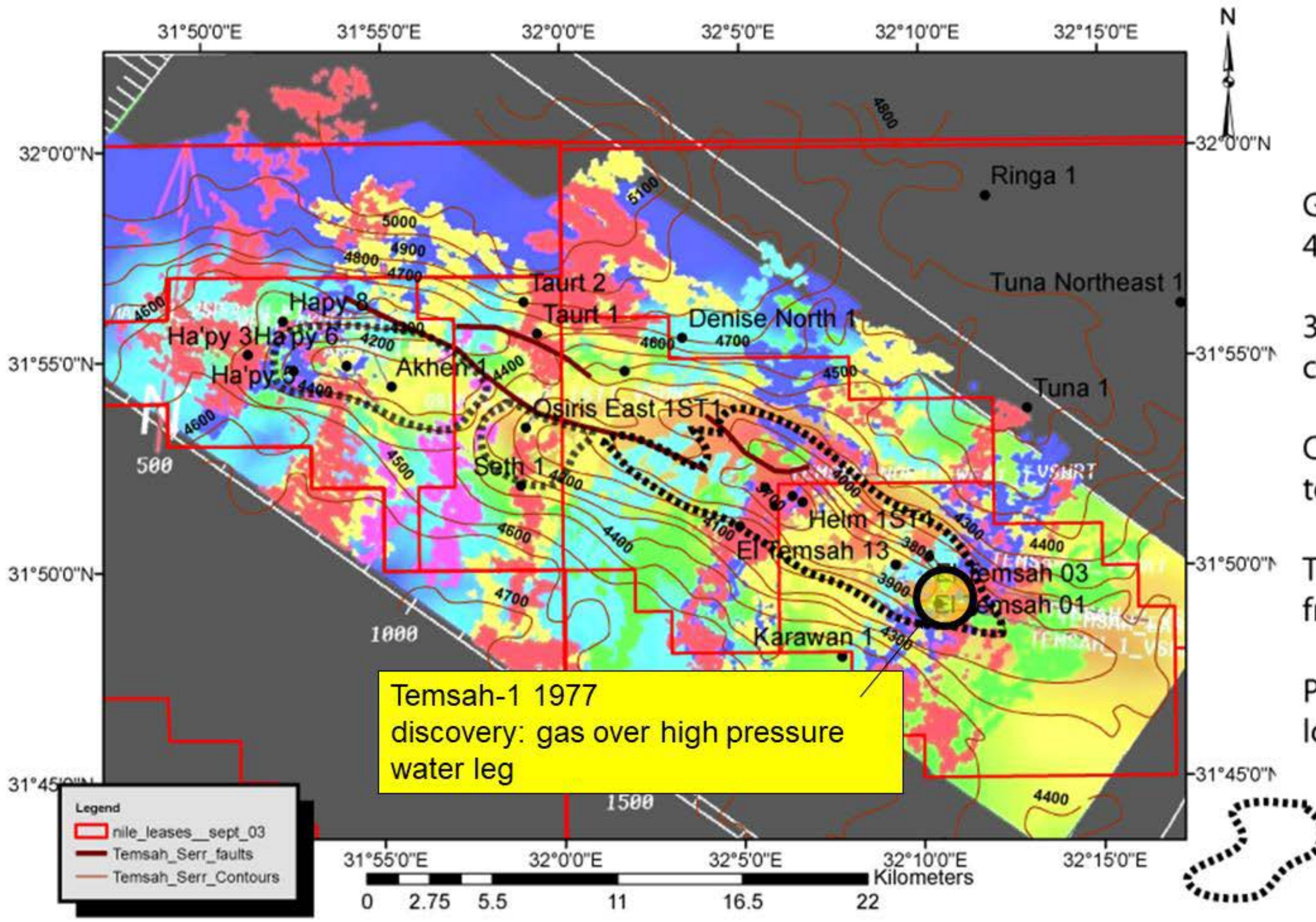
Bummer.

It took 25 years to recognize the tilt and it is still under debate.

Figure 33. Temsah-Akhen Anticline structure map and generalized gas accumulations.

Plenty of opportunity for compartmentalization and perching in slope channels

Temsah-Akhen field complex: Top Serravalian structure and slope channel seismic amplitudes



Greater Temsah structure 450-500 meters of closure

350-400 meters gas column in Miocene

Column limited by top-seal capacity

Tilted gas/water contact from SW-NE

Perched water in channel lows

Approximate field outline

Figure 34. Slope channels crossing the Temsah Anticline used to argue complex perching of water.

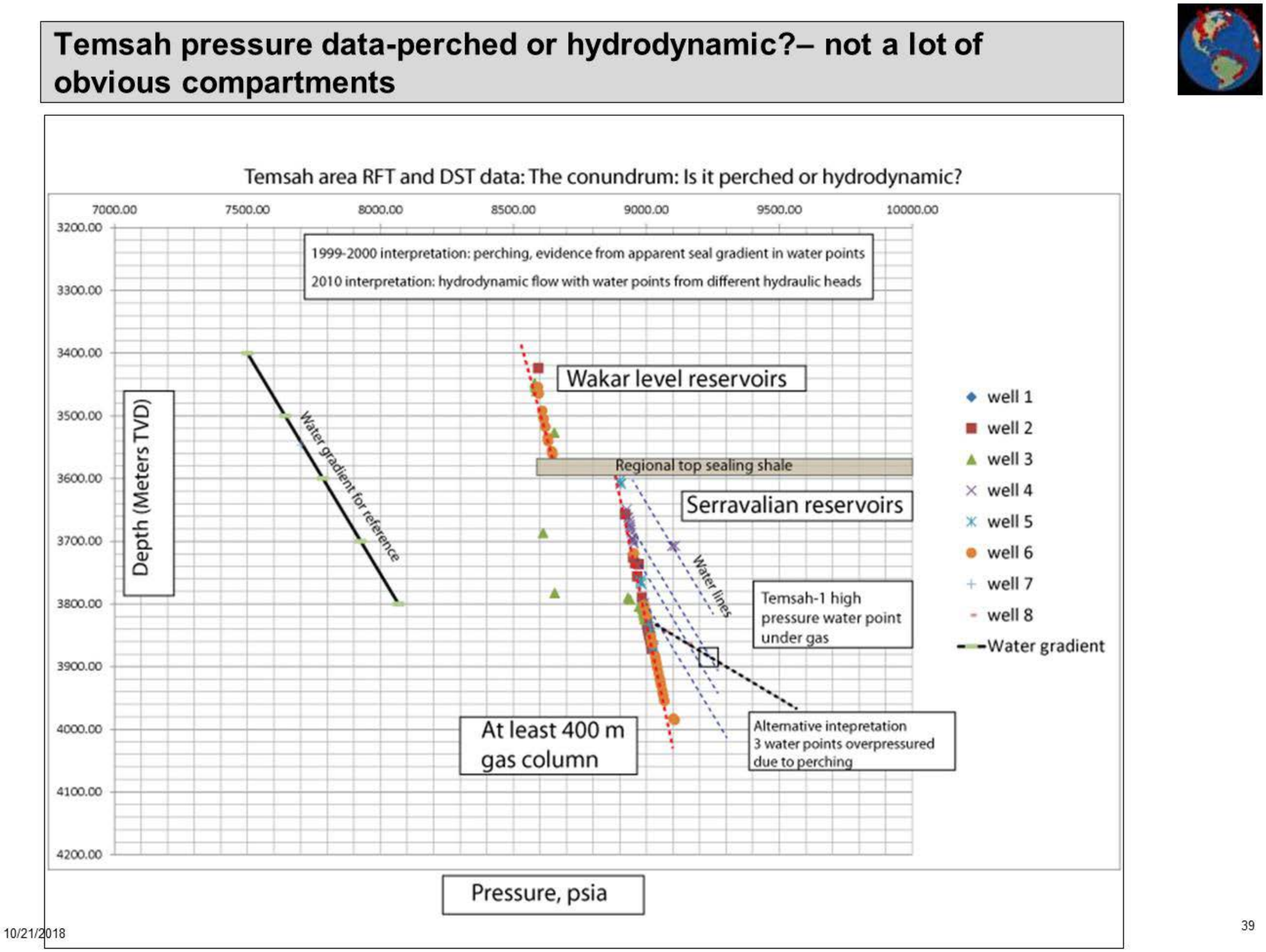


Figure 35. Temsah pressure vs. depth plot. Hydrodynamic or tilted?

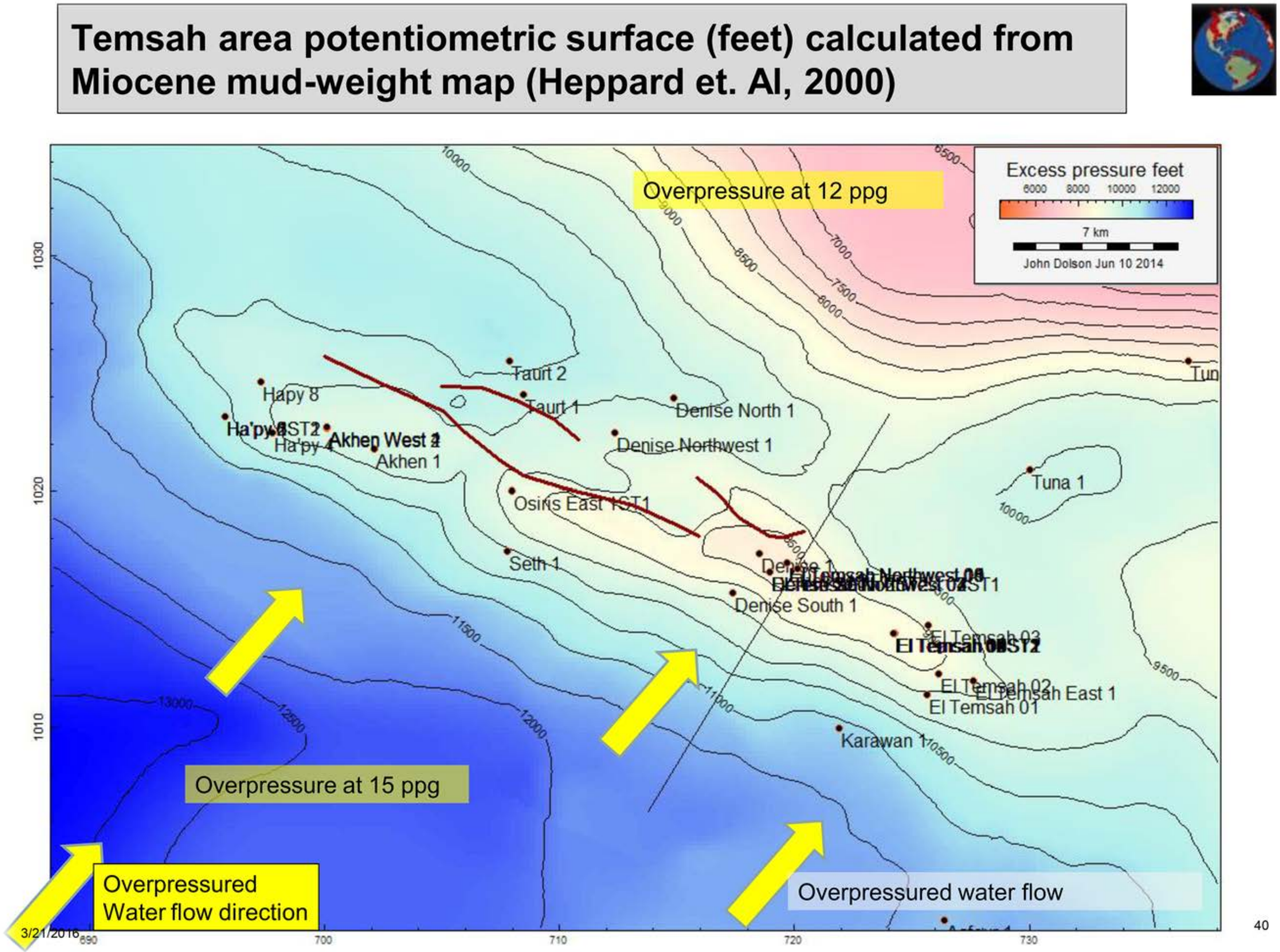


Figure 36. Potentiometric map as input to migration modeling.

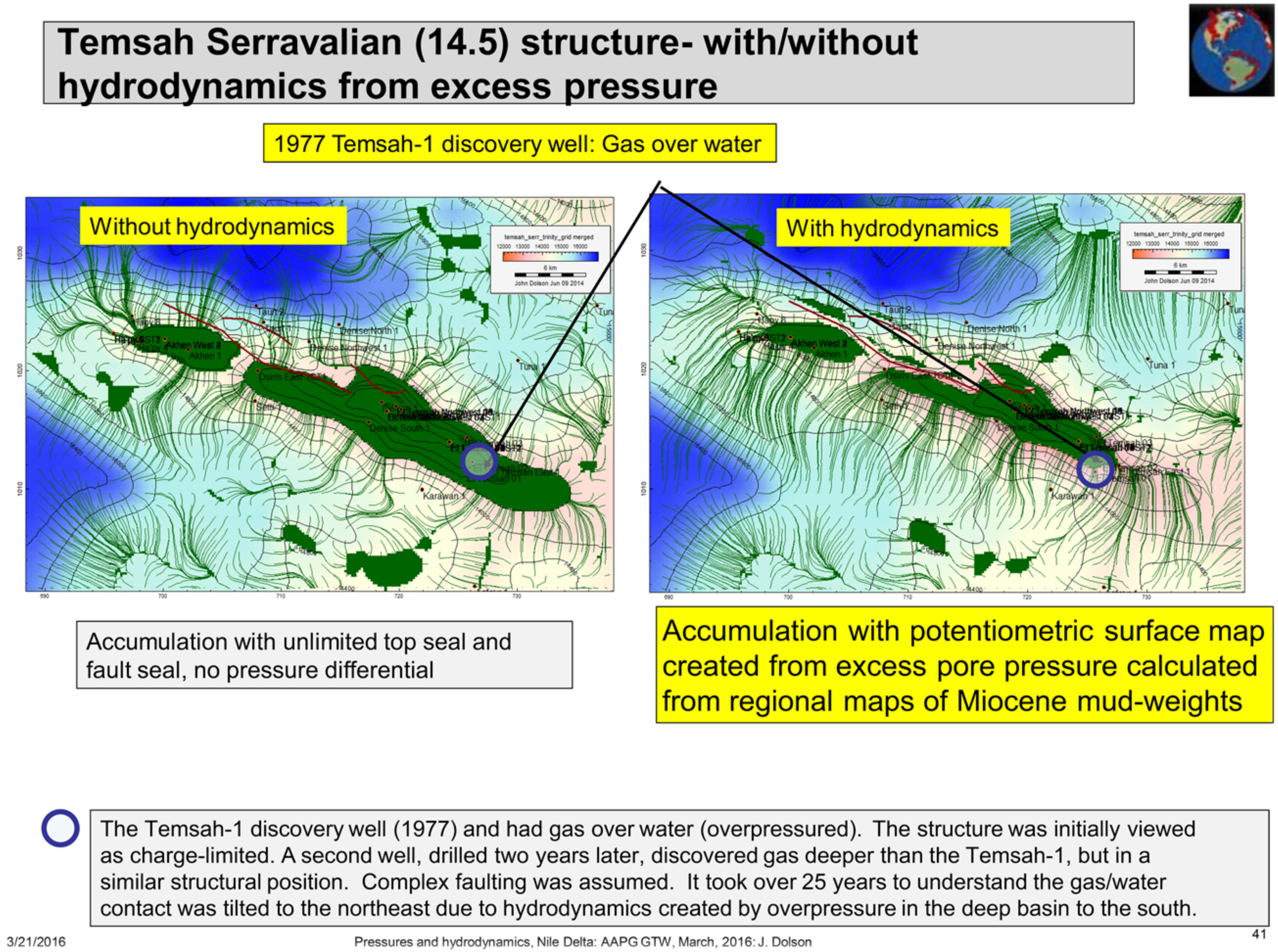


Figure 37. Resultant migration models.

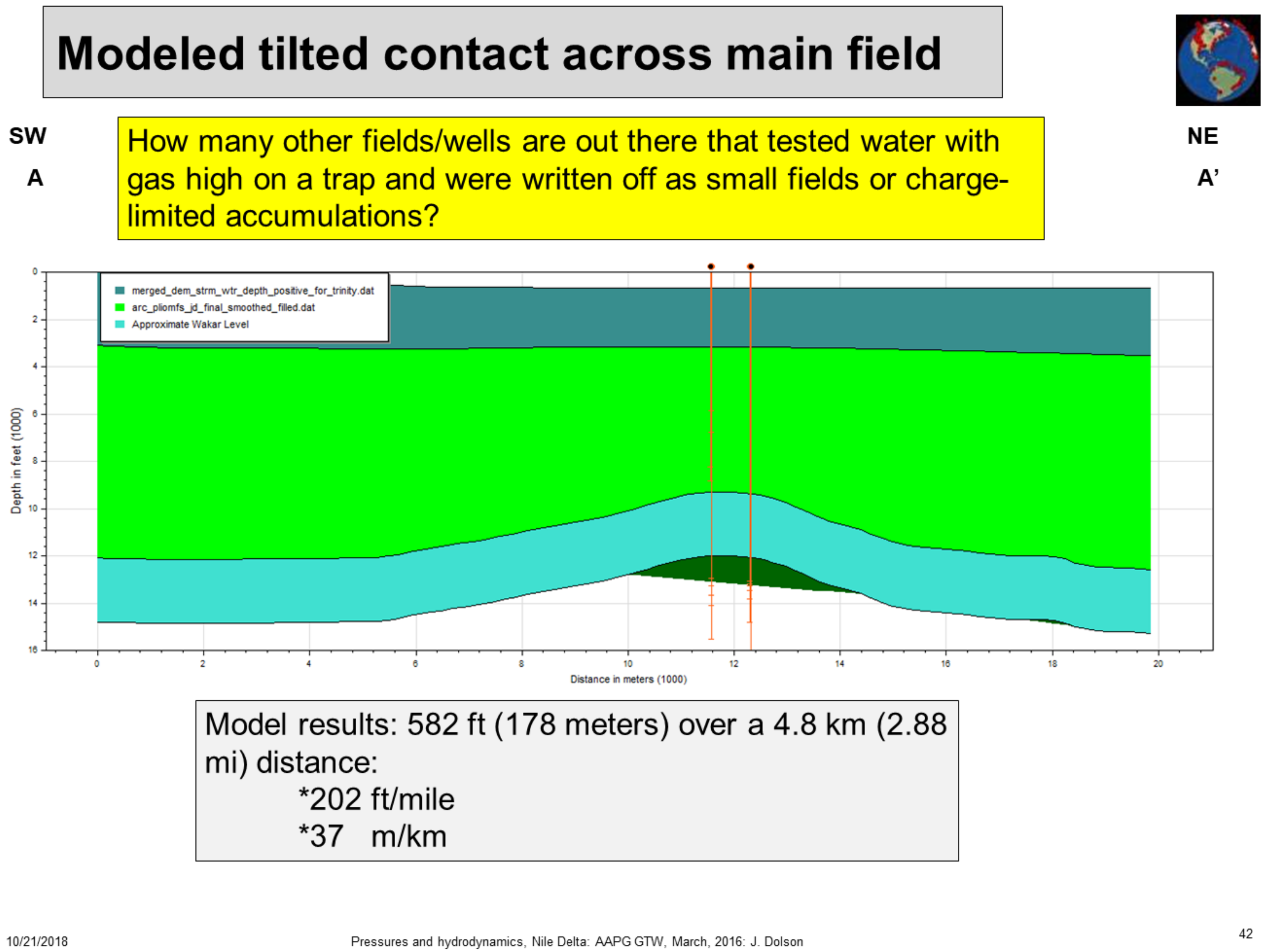


Figure 38. Cross section through the Temsah Field showing modeled gas-water contact (dark green).

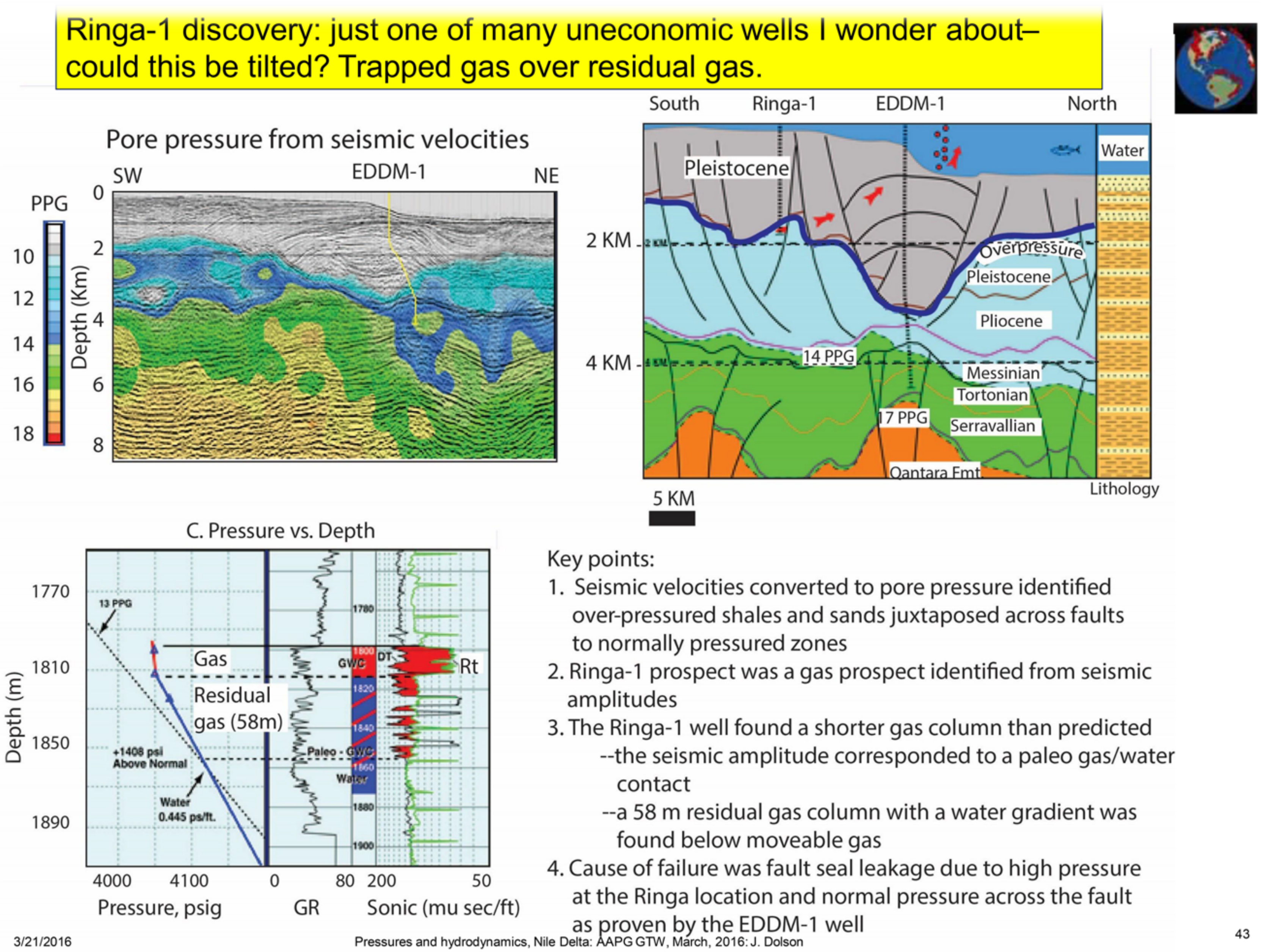
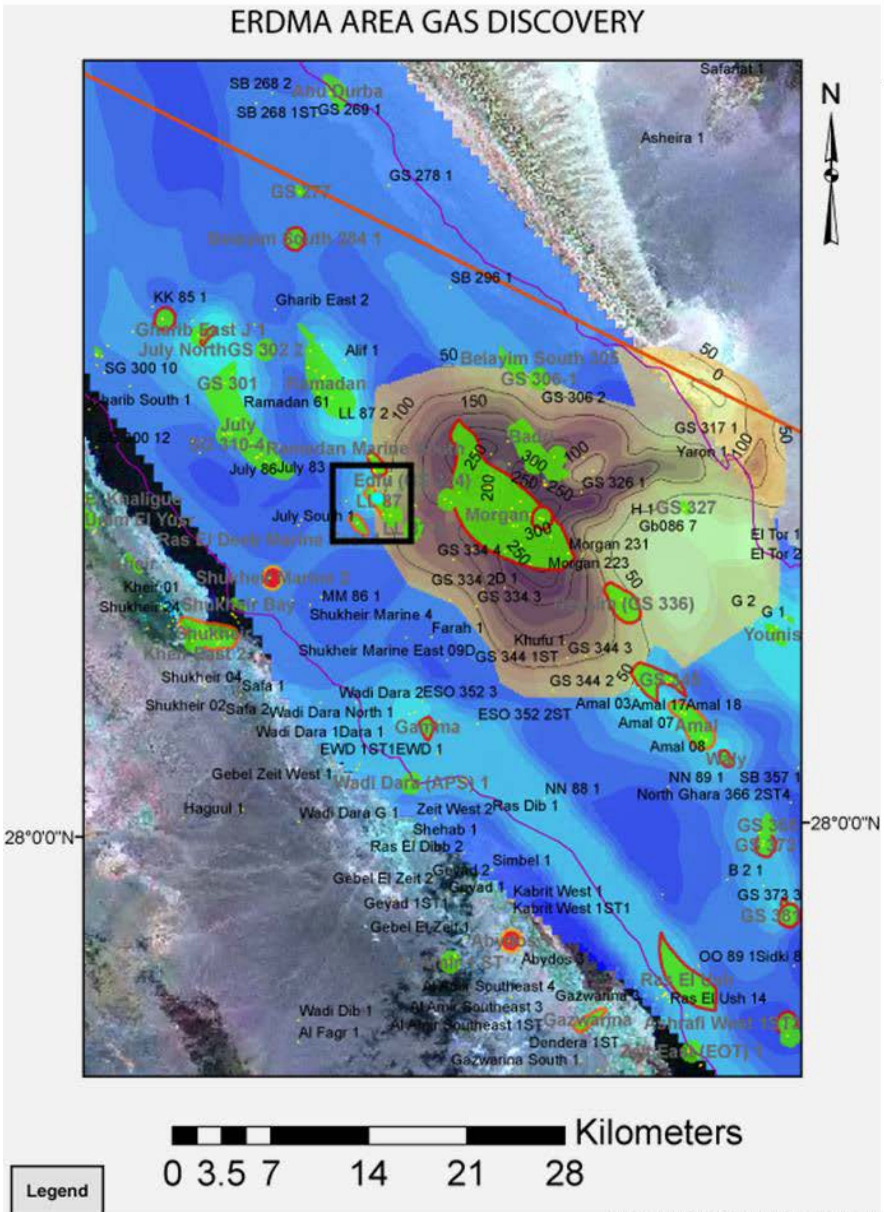
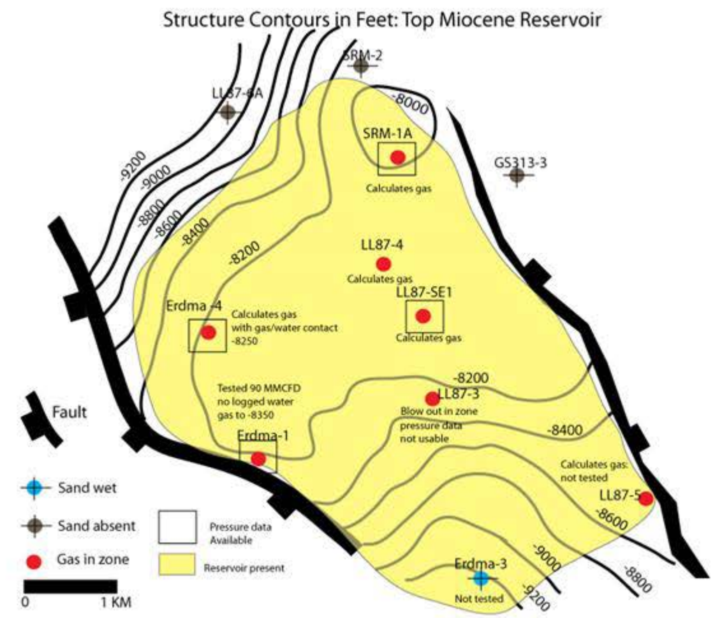


Figure 39. Hydrodynamic tilt or residual gas?



A known combination trap: 150 BCF Gas Field–Morgan fan pinchout



Discovery well (Erdma-1) drilled in 1985 down-flank; tested 90 MMCFD with condensate. Offset well (Erdma -1) encountered gas and water shallower and was considered in a separate trap. The field was restudied in 1995 and pressure data indicated perched water and connectivity in all wells in one large stratigraphic trap. A subsequent twin to the Erdma -1 was the most prolific well in the GOS for GUPCO for over 18 months with no pressure drop.

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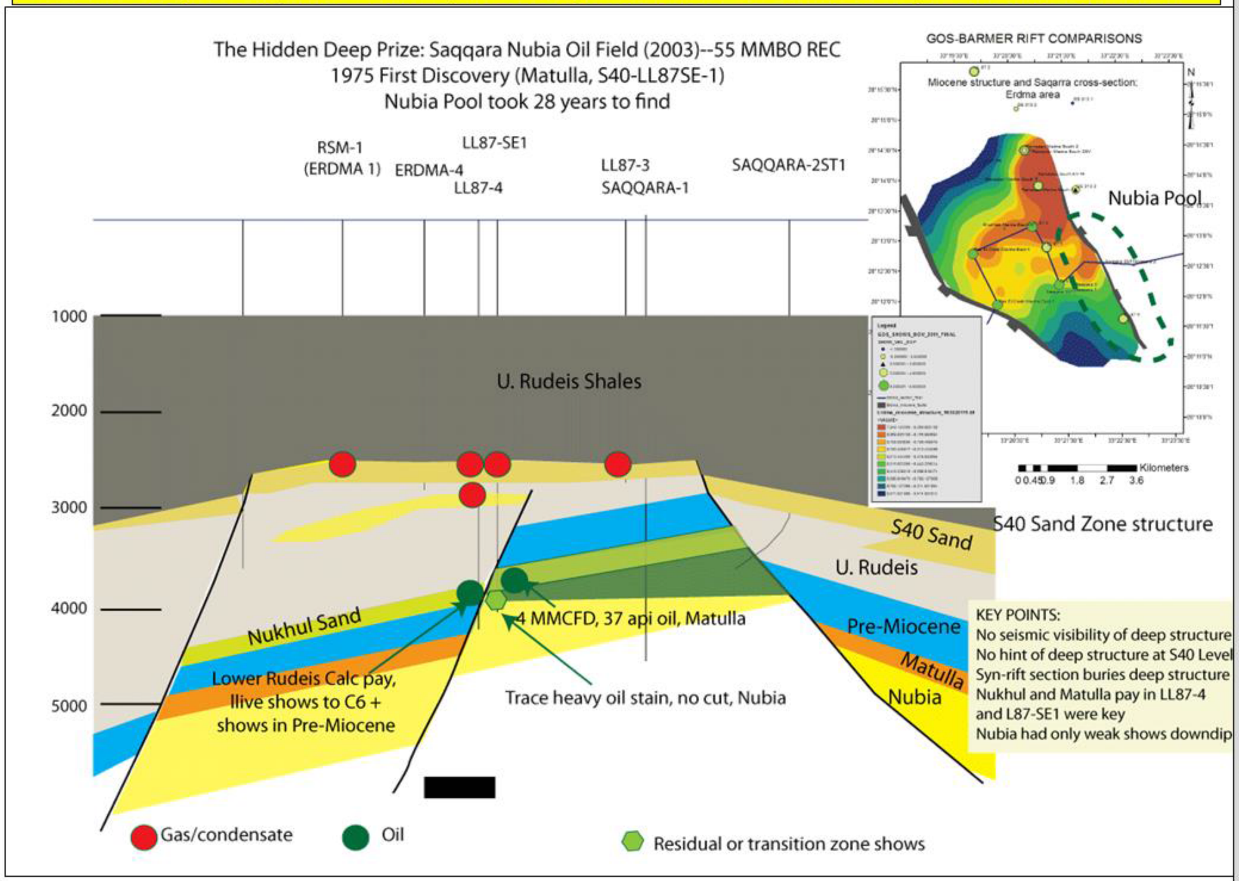
Figure 40. Southern Gulf of Suez Erdma area Miocene syn-rift sandstone combination trap.

And UNDER the gas: the Saqarra Nubia oil field 28 years to discovery of deep fault blocks (somewhat schematic)

2003 discovery: concept and initial maps made by 1998 at GUPCO based on dipmeters and oil shows



Seismic imaging in the Gulf of Suez is so poor that even the S40 sand zone was difficult to shape structurally. Structure maps were from gross seismic shape and then dipmeters and hand-contoured geological maps.

Test and show data deep always suggested a deeper Matulla and Nubia accumulation. Good geological integration shaped out this picture in the late 1990's. Seismic de-multiple reprocessing shaped out the deep structural block in early 2000. In 2003, BP drilled two of these structures, with a combined recoverable of about 100 MMBO. The Saqarra trap is offset to the east and southeast from the shallow closure at the S40 level.

Message: there will be other seismically 'hidden' deep structures in the basin: break-though imaging needed.

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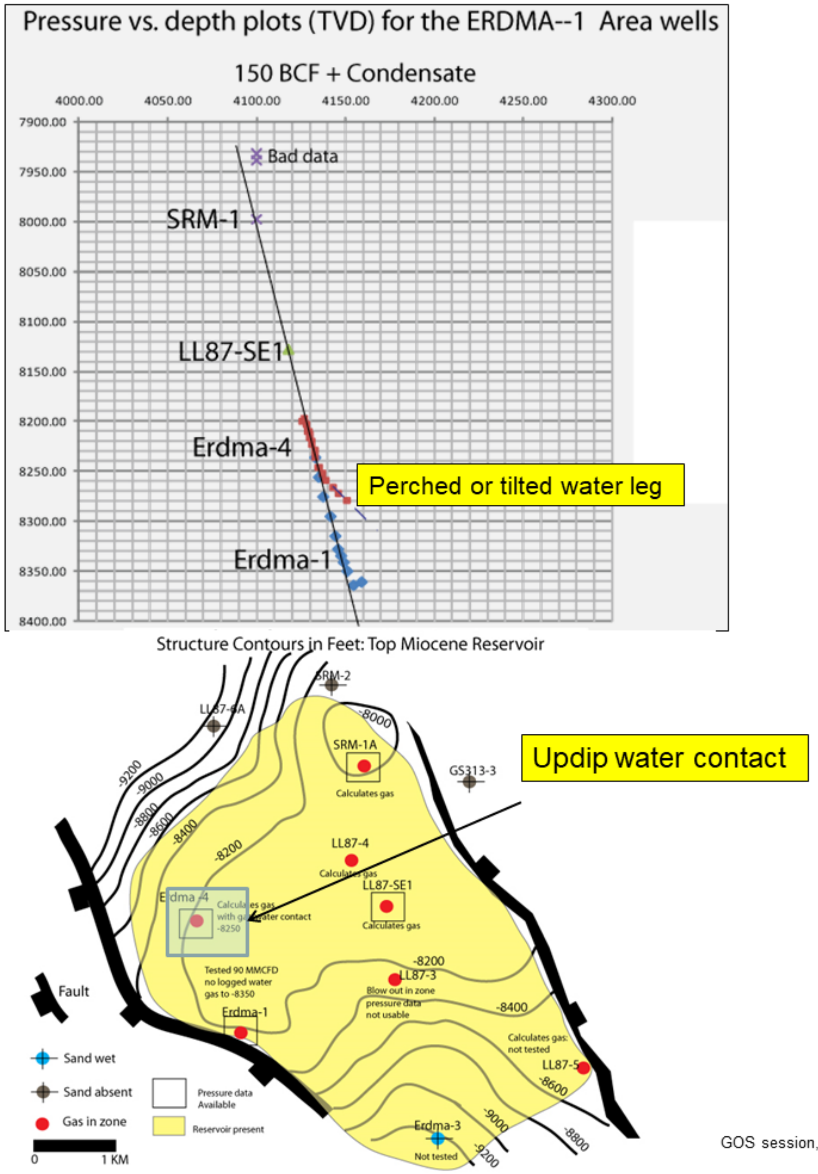
Figure 41. Diagrammatic structural section over the Erdma area structure. The deeper oil pool in the Nubia Formation was discovered by BP in 2003, keying off down-dip wells with shows and tested hydrocarbons down-dip of the Nubia pool. The exact depths and shape of the deeper pool are somewhat schematic, as a full data set is not available to accurately depict the deep trap.



GOS session, J. Dolson

The key to the Erdma gas field commercialization was recognition by GUPCO staff in 1995 (10 years post abandonment of all the wells as uneconomic) that the wells were connected in one common gas column.

Original pressure-depth plots were done in measured depth and appeared to show compartments. TVDSS corrected data showed continuity and water in the Erdma-4 interpreted as perched or tilted, leaving a significant volume of gas.

In 2001, GUPCO re-evaluated deep structure and found two Nubia fault blocks below this field holding 180-120 MMBO recoverable.

Figure 42. Pressure vs. depth plot in the S40 sand interval. This gas-condensate reservoir may actually be vertical seepage from the deeper oil in the Nubia section at Saqqara Field. The Edfu discovery is another deeper pool discovered during this same re-evaluation of the deeper structural trend (not shown on this diagram).

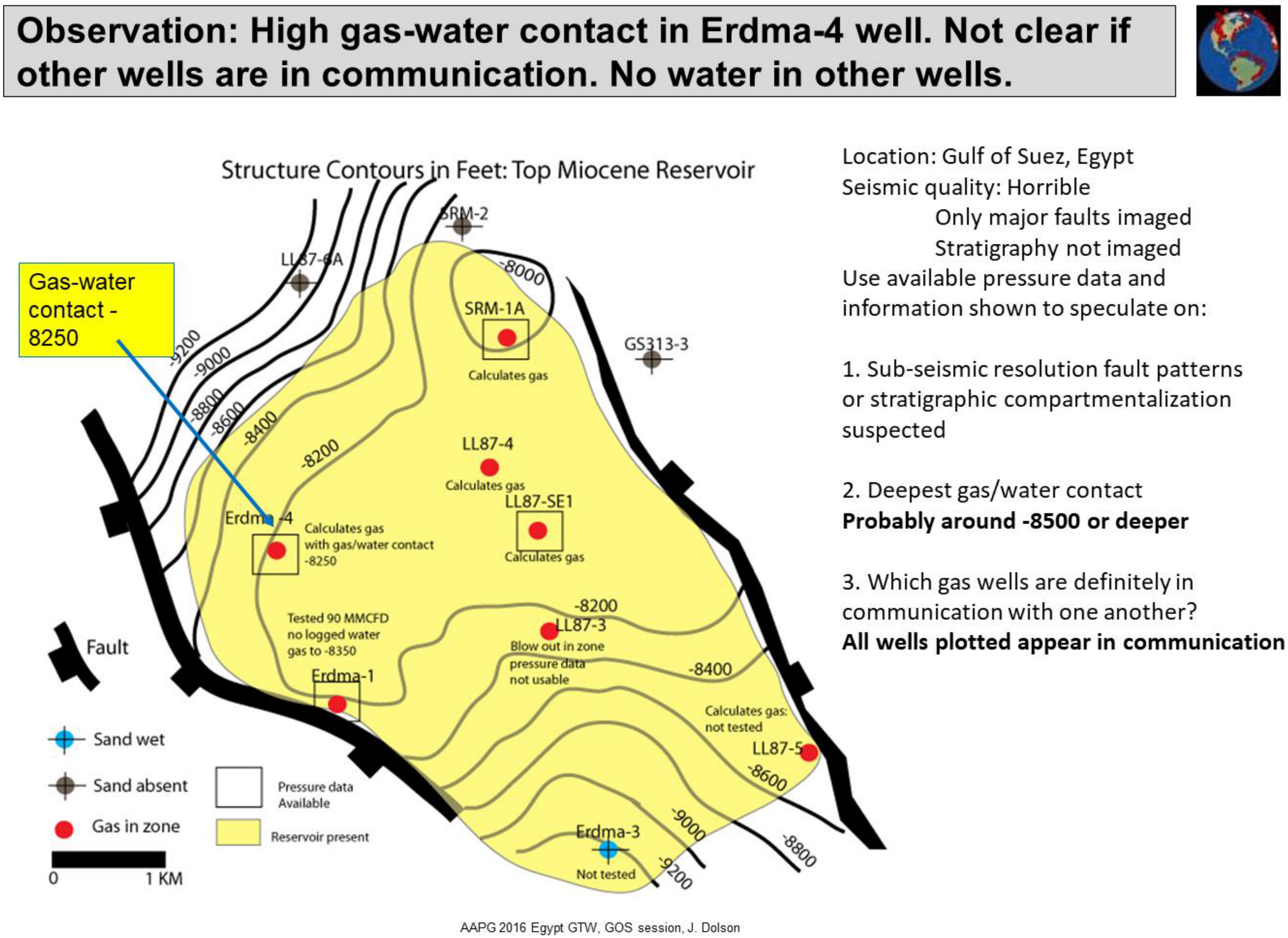
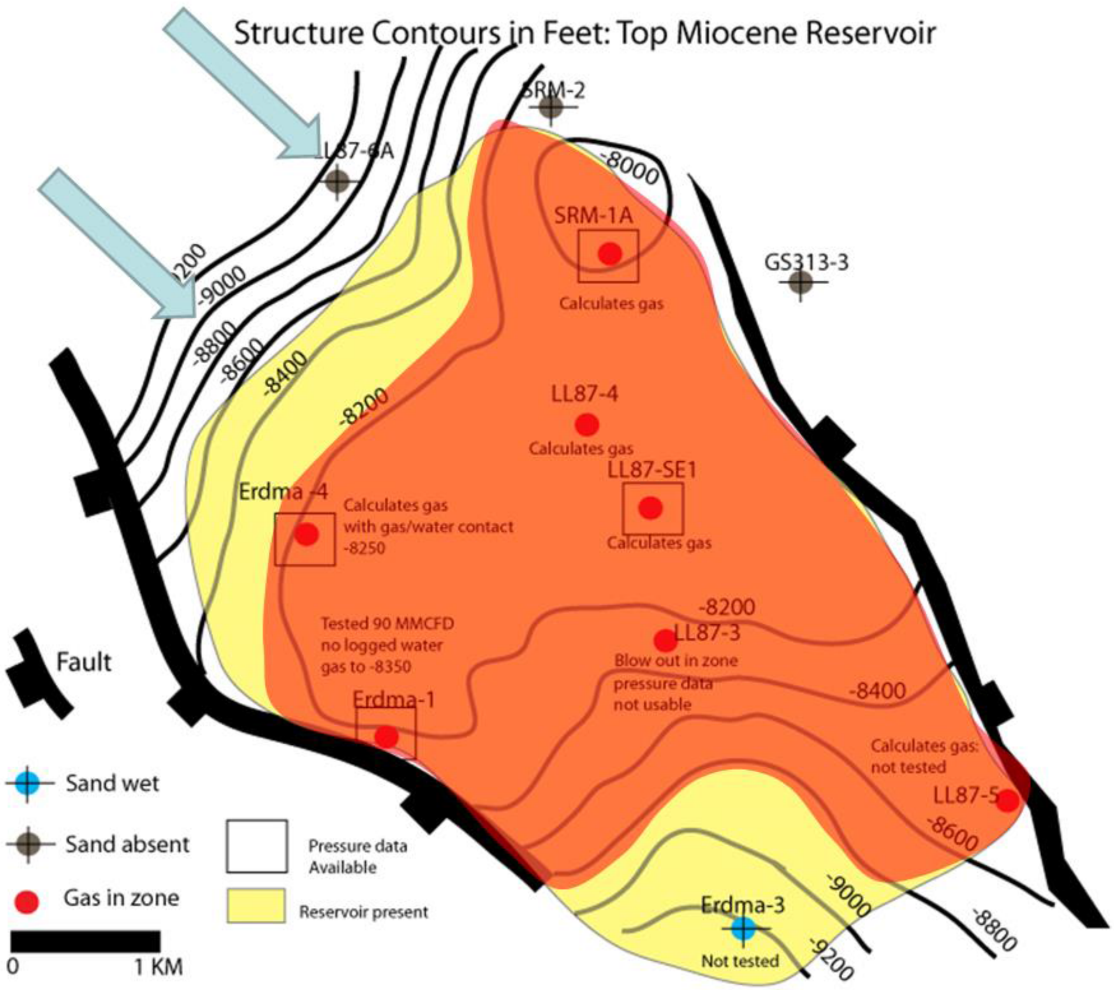


Figure 43. Test summaries on the S40 reservoir. The pressure plot shown in Figure 42 indicates that at least four of these wells are in pressure continuity.

Simplest solution: Tilted contact. Perching is also possible, but more difficult to do as the stratigraphy looks simple.



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Location: Gulf of Suez, Egypt
Seismic quality: Horrible
Only major faults imaged
Stratigraphy not imaged
Use available pressure data and information shown to speculate on:

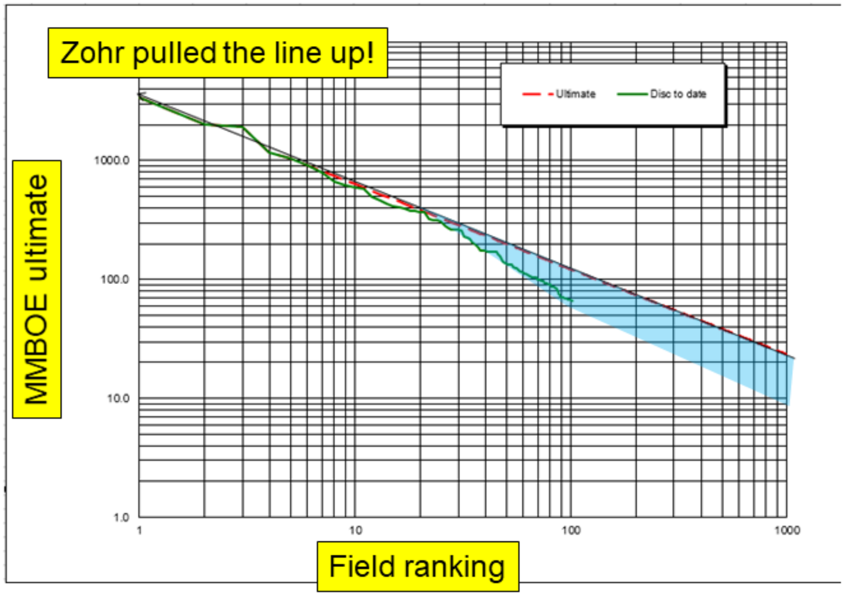
1. Sub-seismic resolution fault patterns or stratigraphic compartmentalization

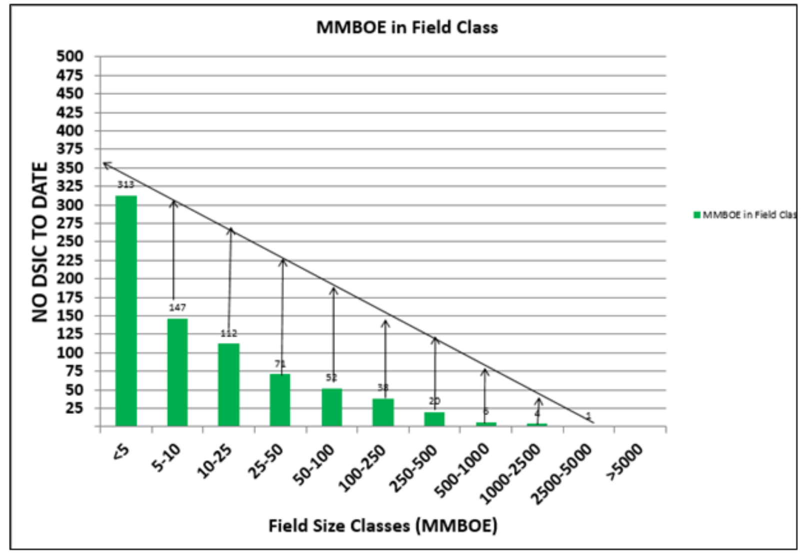
2. Deepest gas/water contact
Probably around -8800

3. Which gas wells are definitely in communication with one another?
All wells plotted appear in communication

Figure 44. Hydrodynamic tilt model of the SW sandstone.

What's left out there to find?—post Zohr update of Dolson et al., 2014 estimates (AAPG)—where from and what are the barriers?





Statistical yet-to-find for Egypt: 38.6 BBOE (224 TCF), still in line with 2014 predictions. A lot left, much of it in the Nile Delta.

Figure 45. How much oil and gas is yet to be found in Egypt? A speculative 2016 modification of Dolson et al. (2014).