Reservoir vs. Seal Pressure Gradients: Calculations and Pitfalls*

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Abstract

There is confusion about calculating pore pressure gradient in permeable beds (reservoirs) versus very low permeable beds (seals), especially in the geopressured section. Geoscientists are inclined to use pressure values in psi and kPa. On the other hand, drilling engineers prefer to calculate subsurface pressure values expressed in pound per gallon mud weight equivalent (ppg mwe). Equating the subsurface geopressured entrapped fluid in the reservoir to the manmade, changeable mud pressure leads to incorrect calibration of pore pressure prediction models. It also creates fictitious pressure regressions on most of the reservoir pressure's P-D plots, displays and gives the impression of a so-called centroid effect.

Methodical examination, calculation and prediction of subsurface pressure in a widespread database from the shallow and deep waters of the Gulf of Mexico demonstrate a distinctive discrepancy between pressure behaviors in seals versus reservoirs. Therefore, the two lithological unit's petrophysical properties should be examined and interpreted separately due to the impact of the geopressure partitions.

The four subsurface geopressure zones (A, B, C and D), introduced in this study, explain the fundamentals of pressure measurements and interpretation in reservoirs, in addition to the basics of pressure prediction methods in seals. The top of geopressure (TOG) between the normally pressured and geopressured subsurface sections marks the pivot zone where the pressure gradients in both reservoir and seals divert. A hydrodynamic flow above TOG is usually associated with sediment dewatering. On the other hand, geopressured pressure gradient in a virgin reservoir shows a hydrostatic gradient with cascaded excess pressure envelopes.

The gradient's slope in each of the sub-surface's four zones is contingent on the vertical subsurface compartmentalization, stresses, rock formation's permeability and fluid density. Exploration risk, including sealing integrity, hydrocarbon trapping capacity and drilling challenges are greatly impacted by the subsurface geopressure gradients abnormality. Foreseeing the subsurface pressure gradient perturbation is essential for assessing the prospect's risk and the possible drilling hurdles prior to moving the rig on the proposed location.

Introduction

For a long time, the industry implemented, a hybrid pressure-depth plot combining the pressure in psi and ppg mwe on the same display for analysis. Therefore, standard mathematical transformation gradient conversion factors of 1/0.052 emerged to convert from psi/ft to ppg mwe and 0.852 from kPa/M to ppg mwe. These conversion factors can be acceptably applied in the seals; however, it is erroneously applied in the reservoirs (Bruce and Bowers, 2002). Moreover, this hybrid depth vs. psi - ppg combined plot gave birth to a new phenomenon identified as the Centroid (Traugott, 1997). The calculation of pressure gradient in reference to the subsea, RKB, DF can leads to a serious misleading calculation. The pressure gradient's calculation by Dickinson, 1953 lead to unintended belief that pressure gradient (PG) decreases with increasing depth.

The four subsurface geopressure zones, introduced in this paper, explain the fundamentals of pressure measurements and interpretation in reservoirs and the basics of pressure prediction methods in seals. The top of geopressure (TOG) between the normally pressured and geopressured subsurface sections marks the pivot zone where the pressure gradients in both reservoir and seals divert. A hydrodynamic flow above TOG is usually associated with sediment dewatering. On the other hand, geopressured PG in a virgin reservoir shows a hydrostatic gradient with different excess pressure envelopes. Reservoir and seal pressure gradients in each of these zones behave differently. The change of the gradient's slope in each of these zones is mainly contingent on the vertical subsurface stress, compartmentalization and fluid's density. The excess pressure generated by geopressure in reservoirs should stay in the same hydrostatic window dictated by the sealing capacity of the shale above. However, the predictable excess pressure trend in the seals follows the principal stress (overburden) trend. Pressure transgression and regression and, accordingly, sealing capacity is greatly impacted by the geological building blocks of a specific prospect. The comprehensive evaluation of the PG changes in each of the four zones sheds light on the possible cause of the hazardous shallow water flow in deep water. It also justifies the presence of sizeable hydraulic head in the geopressured zone that causes hard kicks and well blow out. A model of calculating the disparity between reservoirs versus seal pressures along a tilted structural feature is herein introduced. This is in contrary to beliefs of a hypothetical Centroid point as a cause.

This study advocates the preferred methods of seal's PP prediction and calibration models. It also sheds light on the common pitfalls of PG calculations in reservoir beds. Exploration risk, drilling challenges, and the economic feasibility of a prospective play are greatly impacted by the subsurface geopressure gradients abnormality.

Subsurface Compartments

The slope on the pore pressure gradients are mostly dictated by compartmentalization. Subsurface compartments are mainly initiated due to changes in lithology, sedimentation rate and structural patterns. The vertical generic pore pressure profile in the subsurface can be, in most cases, divided into four zones (Figure 1). This finding has been established based on integration of a large database of pressure and petrophysical measurements (Figure 2) from the Gulf of Mexico area. The zones are:

A - Free Flow Zone: The very shallow free flow section (A) is usually in communication with the seafloor in offshore and groundwater onshore. The thickness of this thin zone relies on the sediment input from the deposition feeders system. The fluctuation in sea level and groundwater flows impacts the hydrologic behavior of this zone in offshore and onshore, respectively. The top of this zone is at the mud line (seabed) offshore and at the ground-water table onshore. The base of this zone is defined at a depth where the process of dewatering starts (top of zone B); where the low permeable sediments and overburden stress reach the equilibrium phase. The encroachment of brackish and fresh water in this zone sometimes leads to higher well log resistivity measurements (Figure 2).

In offshore, the pressure of the sand and shale of these upper unconsolidated sediments have the same gradient (+/- 0.465 psi/ft in GoM) and is a function of depth and seawater density. On the other hand, in onshore, where surface topography has a great impact on the hydrology of this zone, lateral piezometric pressure's gradient applies. Potentiometric surface mapping is used to calculate ground water flow and potential hydrocarbons in this zone (Dahlberg 1994).

B - Hydrodynamic Zone: It starts where sediments begin to expel water to zone A, due to the depositional load (overburden). It bottoms at the top of the geopressure (C). This unconfined hydrodynamic zone forms due to the equilibrium compaction process. This zone shows a gradual increase of pressure's gradient with depth (Figure 3) in both sand and shale. It ranges from hydrostatic at the top to a higher gradient value at the bottom where the process of disequilibrium dewatering is ceased (Shaker, 2007).

The sand and shale pressures in this active hydrodynamic segment are functions of depth, formation water density and viscosity, sediment permeability and the upward force's vector generated by the fluid's flow (ΔP). Darcy's law would apply in this zone to establish the relationship between flow and pressure gradient:

$$Q = - k/\mu * \Delta P$$

Where Q = fluid flux (discharge per unit/time), k = permeability, μ = fluid viscosity, and ΔP = pressure gradient.

The fluid influx throughout the sediments, from deep to shallow, due to the dewatering process, sometimes gives the false impression of the presence of a shallow/near surface geopressured zone. In Keathley Canyon Block 255; where BP extensively took RFT's measurements from the entire well; the upward pressure gradient decreased gradually from 0.621 psi/ft to 0.520 psi/ft between depth 11,500' and 9,800' respectively (Figure 3). The differential flow rate (Darcy's flux) between the sand and clay/shale, due to permeability contrast, causes several drilling hazards. Most of these hazardous challenges occur when the drilling bit crosses from a low permeable (shale/mud) layer to a sand bed below. The abrupt increase of formation water flow influx across the beds interface leads to a strong mud cut and possibly resulted in flow – kill – loss of circulation cyclical event. This phenomenon is known in some of the deepwater exploration areas as shallow water flows (SWF).

In this zone, the petrophysical properties (resistivity, velocity, and density) exhibit a gradual change with depth that corresponds with the porosity reduction due to the gradual increase of compaction. The pore pressure prediction analysts refer to the slopes on these well logs petrophysical measurements as the Normal Compaction Trend (NCT) (Figure 2). The shale shows an exponential slope corresponds with the NCT (Figure 2), whereas sand exhibits a linear trend (Figure 3).

C - The Transition Zone: positions between the hydrodynamic system (B) and the confined geopressured system (D) and represents the top seal of the entire section below. It represents the subsurface top cap where fluid is not capable of escape. This section, in general, is built of a regional condensed shale section of high stand depositional stratigraphic sequence i.e. *Cibicides opima* shale in offshore Texas. The thickness of this zone can range from tens to several hundred feet. The pressure gradient in this relatively short interval significantly increases. This pressure transgression is contingent on the seal age, thickness and lithology. It is noticed that during drilling of older sediment mud weight needs to be raised three pounds to penetrate this zone i.e. Gulf Coast and shallow offshore shelf. However, in younger sediments and deep-water wells, mud weight is subtly raised between one and two pounds.

Usually, this zone is identified in geopressure practice as the top of geopressure (TOG) or the fluid retention depth (FRD). This relatively under-evaluated zone represents the boundary between the static confined sealed zone (D) below and the dynamically breached zones (B /A) above. This zone represents a distinct pivot point for the petrophysical properties' measurements to reverse values (Figure 2). Velocity, resistivity, and density decreases, whereas, DT, conductivity and porosity increases subsequent to crossing this zone.

This zone signifies the cut off drilling depth for finding hydrocarbon without setting an intermediate casing seat. Moreover, the hydrocarbon optimum trapping mechanism is favorable just above this zone. This is because hydrocarbon hovering in permeable beds above this zone during the migration from the geopressured (D) to the hydrodynamic (B) section.

D - The Geopressured Zone: Reservoirs and seals in this confined hydrostatic section show distinctly different gradients, however, they form an overall cascade-shaped profile (Figure 1).

Reservoir's pressure shows a static linear gradient contingent on the fluid's density (water, brines, oil, and gas) in the pore spaces. The pore pressure in reservoirs can be calculated as follow:

$$Pz = 0.433 * \mu * Z \qquad (1)$$

Where Pz= pressure at depth z, μ= fluid density, Z= depth, and 0.443= fresh water pressure gradient in psi/ft at 60 º F.

The excess pressure (EP) is the difference between the formation pressure and the regional hydrostatic pressure in a reservoir at Z depth (Shaker 2001):

$$EPz = Pz - Hz \qquad (2)$$

Where Hz = regional hydrostatic pressure.

The EP window should stay constant in a single wet reservoir (Figure 4). Therefore:

$$EP@Z1 = EP@Z2 \qquad (3)$$

In Garden Banks 248 well #1, note the presence of three compartments. Each wet reservoir compartment carries the same EP. However, the lower pay zone between 21,000'and 21,700' shows a larger EP at the hydrocarbon-bearing zone than the wet sand below due to the steep gas gradient. To predict pore pressure at depth Z2 in a virgin reservoir where pressure is known at Z1 (Figure 4):

$$P2 = P1 + (Z2 - Z1) * \Delta P \tag{4}$$

Where, ΔP = fluid pressure gradient = 0.433*µ.

__The sealing capacity (SC)__ represents the pressure shift between two consecutive compartments (Figure 5). The shift from one pressure envelope to a deeper one across the seal defines the sealing capacity of the inter-bedded seals (Shaker, 2001). The successive subsurface pressure compartments (envelopes) should bear the same fluid formation gradient, as long as the paleo-formation water salinity stays in the same proximity.

Competent seal is represented by a positive shift, whereas negative shift (Figure 4 and Figure 5) reflects seal breach due to a structural failure (fault, salt interface, unconformity .etc). On the other hand, the alignment of pressure measurements of several compartments indicates communication (Figure 13). Virgin reservoir (in absence of hydrocarbon) usually exhibits the hydrostatic gradient of the formation fluid (0.465 psi/ft in GOM) and progresses with depth, in a cascade fashion crossing the intercalated seals (Figure 1, Figure 4 and Figure 5).

Wire-line tools; such as repeated formation tester (RFT), modular dynamic tester (MDT) etc; measure pressure in permeable beds at specific depth. Noteworthy, shut in pressure (SIP) represents the formation pressure at the wellhead of the reservoirs in the uncased open-hole section. Moreover, the reservoir bears a hydraulic head because of the excess pressure (Figure 6).

__The hydraulic head__ (HH) is the potential height of the formation fluid (water, oil or gas) to rise above a reference point i.e. RKB, Sea level, well head, ground level (Figure 6). The excess pressure in Zone D and the potentiometric difference on-land are the driving mechanism for generating the HH. The height of HH in Zone D can be calculated as:

$$HH = (EP / \Delta P) - RKB \tag{5}$$

Where EP = Excess pressure in psi, RKB = reference Kelly bushing (above SL), ΔP = formation fluid (water, oil and gas) pressure gradients = density* 0.433.

Noteworthy formation water, oil, and gas pressure gradient follow linear trends, contingent on their density, in permeable reservoirs (Figure 6). Gradient changes slope in a multiple phase reservoir at the interception point e.g. water/oil/gas contacts.

Seal's Pressure follows a higher gradient than formation fluid (Figure 4, Figure 8 and Figure 12) that mimics the lithostatic stress (overburden in a relaxed tectonic system). The pressure gradient in the shale is directly impacted by changes of porosity due to burial, compaction and fluid loss. It shows exponential trends and follows the logarithmic porosity compaction trend of Athy (1930):

$$Ø = Ø_0 * e^{-cz}$$

Where c= constant, z= depth, and $Ø_0$ = initial porosity.

Moreover, the widely used effective stress - pore pressure prediction transformation models in the seals (shale) are based on exponential/power-law trends (Figure 1, Figure 2 and Figure 4). The shale's sonic-pore pressure prediction relationship is expressed as follows:

$$PP = Ps - (Ps - Pn) * (\Delta Tn / \Delta To) \wedge X$$

Where PP= predicted shale pore pressure, Ps= principal stress (overburden), Pn= hydrostatic pressure, ΔTn= normal sonic slowness (Figure 2), ΔTo= measured (observed) sonic slowness, and x = Eaton exponent (Eaton 1975).

The principal stress magnitude plays an essential role in the pressure's acceleration of the overall (seals and reservoirs) subsurface profile. The anticipated cascade-shaped progressive pressure profile sometimes changes course and shows regressive trends (Figure 4 and Figure 5). The divergence between the pore pressure in the shale (PPP) and the sand (MPP) is a consequence of the principal stress magnitude and compartmentalization. The geological building blocks, mainly sedimentation pattern and structural setting, control entrapment and breaching of the formation fluids in the different subsurface compartments.

Mud's Pressure: During the early drilling era, mud had inherited the role of cutting removal and drilling bit lubrication. Borehole stability became an essential mud function after exploration expanded deeper in the highly geopressured environments. The pressure generated at the drilling bit by the drilling mud column and the borehole walls is variable and corresponds to the mud density. Mud pressure is usually measured from a fixed reference point (e.g. Kelly bushing or derrick floor). The mud pressure gradient is always linear through the casing and open hole (Figure 6).

In the geopressured environment, maintaining the balance between the mud pressure and reservoirs/seals pressures, during drilling, is a very intricate process. If the predicted drilling mud pressure is less than the actual reservoir pressure (under-balanced), sand beds flow and lead to mud cut and possible hard kicks. Moreover, the shale section becomes unstable and can result in wall caving with extensively enlarged well bore diameter. On the other hand, if mud pressure, is substantially higher than predicted PP in reservoir, loss of circulation, tight hole and high torque are common drilling challenges. In addition, shale beds can suffer from micro-fracturing and ballooning.

Pressure Gradient's Calculation

Computing the pressure gradient in reservoirs using RFT, MDT etc. data should be calculated between at least two depth point records in the same compartment (Figure 7). Referencing the reservoir geopressured gradient to the subsea level (SL), Kelly bushing (RKB) and Derrick Floor (DF) causes serious mistakes in calculating the reservoir formation's fluids gradient, density and hydrocarbon type (oil or gas). On the other hand, since shale is not capable of flowing, as opposed to sand; pressure gradient in shale can be forecasted in reference to subsea. The shale pore pressure is predicted using seismic velocity before drilling. During and after drilling, a bundle of petrophysical wire line measurements can be used to determine the shale pressure gradients in the different seals below the top of geopressure. As we discussed previously, seal pressure gradient follows power–law forms.

Mud pressure gradient can be expressed in psi/ft, ppg (pound per gallon), kPa/M, and g/cc. The standard gradient conversion factor of 1/0.052 is used to convert mud pressure from psi/ft to ppg mwe; and 0.852 from kPa/M to ppg mwe and vice versa. The mud pressure follows linear trends with an interception point at the RKB. The slopes on the gradient lines vary contingent on the mud weight. They take a fan shape (mud fan) with its tip at RKB if plotted in psi (Figure 6 and Figure 11) and form vertical grid lines if plotted in ppg on P-D plots (Figure 14).

Mud weight can be sampled from the mud pit (expressed in ppg) or measured (in psi) at the BHA (bottom hole assembly) which is known as ECD (equivalent circulating density). Measured mud pressure using the RFT and MDT tools does not represent the real time values, during drilling, since this measurement takes place post drilling in a non-circulating mud condition (Figure 12).

The Impact of Structural Tilt on Reservoir – Seal Pressures

It is known that reservoir pressure at the crest of a structural closure shows higher-pressure values than the predicted shale pressure and vice versa on the prospect's structural flanks. As we previously discussed and justified, the pore pressure in a single geopressured compartment should bear the same excess pressure. As a result, the structural tilt should not affect the gradient or the excess pressure window in the reservoir (Figure 8). The sealed porous and permeable geopressured reservoir should follow the static hydraulic laws in a non-flow system. Therefore, the fluid density is the main pressure driving mechanism in a reservoir. The vertical pressure calculations should be based on equations 1, 2, 3 and 4 in this article.

Zhang (2011) stated the pressures in a hydraulically connected formation could be calculated based on the difference in the heights of fluid columns, i.e.:

$$p2 = p1 + \rho fg * Z2 - Z1$$

Where p1 is the formation fluid pressure at depth Z1, p2 is the formation fluid pressure at depth of Z2, ρf is the in-situ fluid density, and g is the acceleration of gravity.

On the contrary, shale's pressure is a function of the principal stress magnitude (Terzaghi 1943). In the presence of larger overburden on the structural low, shale seems to have a higher pressure. Conversely, on the structural crest, where thinner overburden exists, shale bears lesser pressure. Subsequently, reservoir has the same pressure gradient and constant excess pressure (EP) within the entire tilted exploration structural closure i.e. sealed reservoir. Therefore, it appears that the encased sand's pressure is relatively lesser than shale pressure on the structural low and larger than shale at structural high (Figure 8).

The table in Figure 8 shows the EP calculation on the three wells of Figure 8. Well A is located on the crest of the structure and well C on the down-dip flank of the structure. Well B is located midway between A and C where we assume that the reservoir and seal pressures are equal (5,000 psi). The Gulf of Mexico's hydrostatic and reservoir pressure gradients (PG of 0.465 psi/ft) are used for this calculation and shale PG is assumed equal to the overburden of 1 psi/ft. Applying equations 1, 2, 3 and 4 resulted in a constant reservoir's EP, in spite of the pressure difference between the reservoir and the seal at both of the two wells on the crest (A) and the flank (C).

Dickinson (1953), in one of his conclusions showed that pressure gradient in a tilted reservoir decreases with increasing of depth. He was calculating the pressure gradient in reference to subsea depth (SL). His conclusion that pressure gradient decreases with depth in a structurally tilted reservoir was an unintended confusing calculation. This is one of the common pitfalls in geopressure gradient calculations (Figure 9).

Traugott (1997) applied the hybrid depth-psi / ppg plot to convert the pressure in the reservoir from psi to ppg mwe. This led to the belief that there is a midpoint on the structure (Centroid) where the pore pressure in the reservoir and seal have the same value (Figure 10). His hypothesis states that sand pressure (in ppg mwe) increases above the Centroid point, and, decreases below this midpoint. This gives an artificial impression of pressure regression on most of the reservoirs. This is another common pitfall of using the standard conversion factor in converting pressure from psi to ppg mwe in geopressured reservoirs. The standard conversion factor (SCF) is derived as follows:

From lb/gal to psi/ft . . . 12in^3/231 in^3=0.052 and vice versa from psi/ft to lb/gal …. 1/0.052=19.2.

The SCF is based on KB as the reference point. This mathematically driven SCF is embedded in most of the pore pressure prediction software. Bruce and Bowers (2002) stated in the pore pressure special section of the TLE "Without question, expressing the pore pressure in unit of density is scientifically incorrect."

The display on Figure 11 shows in depth details of a reservoir pp gradient's miscalculation when the hybrid psi / ppg plot is applied. The PP in ppg, as shown from the interception of the reservoir PP in psi with the mud fan lines, exhibits decreasing values with increasing depth. The reservoir pressure trend line intercepts higher MW equivalent of 16# at depth 9,000' and intercepts a MW equivalent of 13# at depth 17,000'.

The argument here is why the actual reservoir pressure in psi increases with depth and conversely, decreases with depth in ppg mwe. This is because the SCF of 0.052 and 0.852 should not be applied in converting pressure from psi to ppg mwe in geopressured reservoirs. However, it is applicable in converting the geopressured shale and normally pressured sediment's gradients from psi to ppg mw due to the lack of hydraulic head.

Therefore, the fictitious pressure regressions, including the so-called centroid effect that appears on most of the RFT, MDT (converted in ppg mwe) are not representing realistic physical data and they are the outcome of PG miscalculation. This leads to erroneous pore pressure models calibration and possibly fatal consequences (blowouts and hard kicks) during drilling operations, especially in deep water. Shaker (2003) discussed the technique of rectifying this controversial conversion factor. Geological compartmentalization and hydraulic head corrections are the foundation of the new calculation model.

Case Histories and Applications

The subsurface four compartments: They are well displayed in KC 255 #1 due to the availability of extensive RFT's and petrophysical measurements in almost the entire well. Figure 12 exhibits:

- The four subsurface compartments.
- The incremental pressure gradient increases in Zone B due to the dewatering as result of compaction (Figure 3 and Figure 12).
- The PP surge of 1,000 psi penetrating the 300' thick shale of the TOG (Zone C).
- The linear hydrostatic pressure gradients in all reservoirs (PP RFT) and the exponential trend in all seals (PPP shale) in the geopressured D Zone.
- Pressure transgressions (PT) and regressions (PR) due to geological setting.
- The disparity between the MW RFT measurement (post drilling) and the real time MW RKB.

Excess pressure as sealing capacity indicator: Using the calculated excess pressure (EP) sheds light on the seals trapping competency. Calculating (equations 2 and 4) and plotting the EP vs. depth for the same well is an excellent sealing assessment method. The graph straightforwardly points to the competent seals and breached reservoirs in the borehole trajectory as shown in Figure 13:

- The TOG can trap a hydrocarbon column (if present) with EP of 700 psi in the reservoir below
- The sealing capacity is not contingent on the seal thickness. S3 is much thicker than S4, however the reservoir below S3 is breached and the thinner S4 is a competent seal and can hold a hydrocarbon column of 500 psi EP.
- Subsurface structural failure is likely to create a breach between reservoirs rather than fracturing the top seal.

Pressure gradient reversal due to using the SCF: Converting the reservoirs PP from psi to ppg mwe using SCF is one of the serious pitfalls in geopressured reservoir calculations. Figure 14 shows an example of 3,500' thick (11,500'-15,000') geopressured reservoir where pressure was measured in psi and consequently converted to ppg mwe. Figure 14 exhibits:

- Hydraulic head can be calculated (equation #5) at any depth (table in Figure 14). For example at depth 14,790' H.H. is +5,200' RKB.
- The drilling mud pressure in psi increases with depth to exert the gradually increasing reservoir pressure with depth (upper panel on Figure 14). These are the factual and realistic values.

- On the other hand, plotting the RFT (FP) values in ppg mwe using the SCF (lower panel on Figure 14) shows a negative (reversal) trend (from 15 to 14 ppg mwe) while the actual drilling mud weight shows a positive increase trend (from.13.5 to 14.5 ppg mwe). This is physically unrealistic for drilling operations.

Summary and Recommendations

1. Sediments, stress and fluids are the main components of forming the subsurface geopressure four zones.
2. Pore pressure (PP) in reservoirs bears linear gradient trend contingent on the formation fluid density.
3. Predicted shale pressure follow power-law forms.
4. The shallow water flow in deep water can be attributed to the differential hydrodynamic fluid influx in zone B rather than, the presence of a very shallow geopressured zone.
5. Pressure gradient in a reservoir should be calculated between at least two measured points in the same compartment.
6. The excess pressure in the geopressured Zone (D) stays constant in the same reservoir except in pay zones.
7. The shale sealing capacity is represented and can be calculated from the pressure shift between two consecutive reservoirs.
8. Converting the reservoir pressure from psi to ppg mwe using the standard conversion factor leads to erroneous pressure profile modeling in the geopressured (Zone D) section. However, the SCF can be used successfully in shale and Zones A and B.
9. The fictitious regression and the Centroid phenomenon are the result of using the standard mathematical conversion factor, which is derived from the hybrid psi-ppg vs. depth plot.

Based on this study and the new findings we recommend:

1. Pore pressure gradient in geopressured reservoirs should not be calculated from reference point (RKB, DF, and SL.).
2. Using the hybrid psi-ppg mwe vs. depth plot to exhibit the PP in reservoirs lead to erroneous calculations.
3. Geopressure modeling calibration, using measured pp, should be done in psi-depth modeling format rather than ppg-depth one.
4. Breaking the Normal Compaction Trend for fitting the ppg mwe – depth model can exacerbate the calibration problem.

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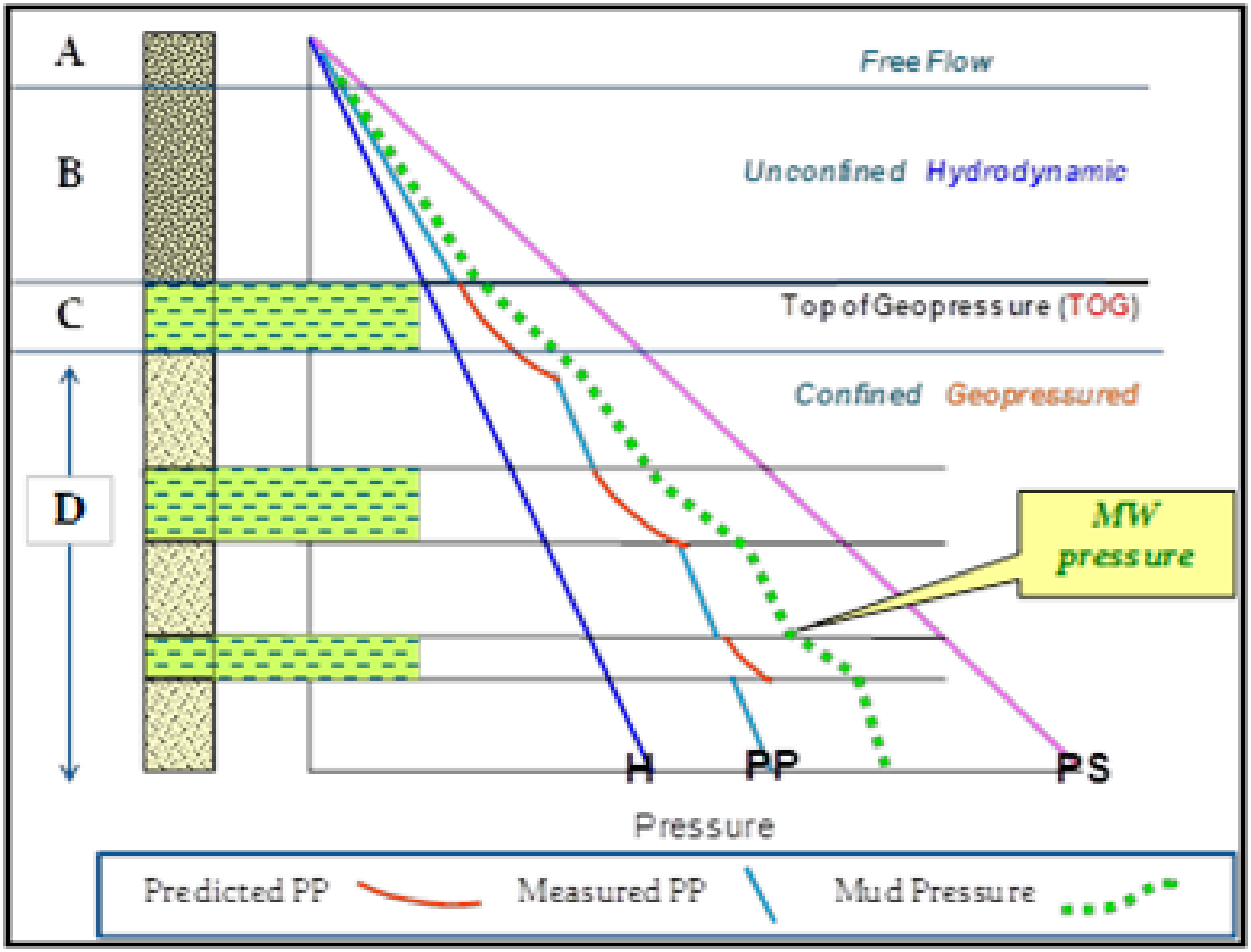


Figure 1. The generic subsurface four main compartments (A, B, C and D). H, PP and PS are hydrostatic, pore pressure and principal stress (overburden) respectively.

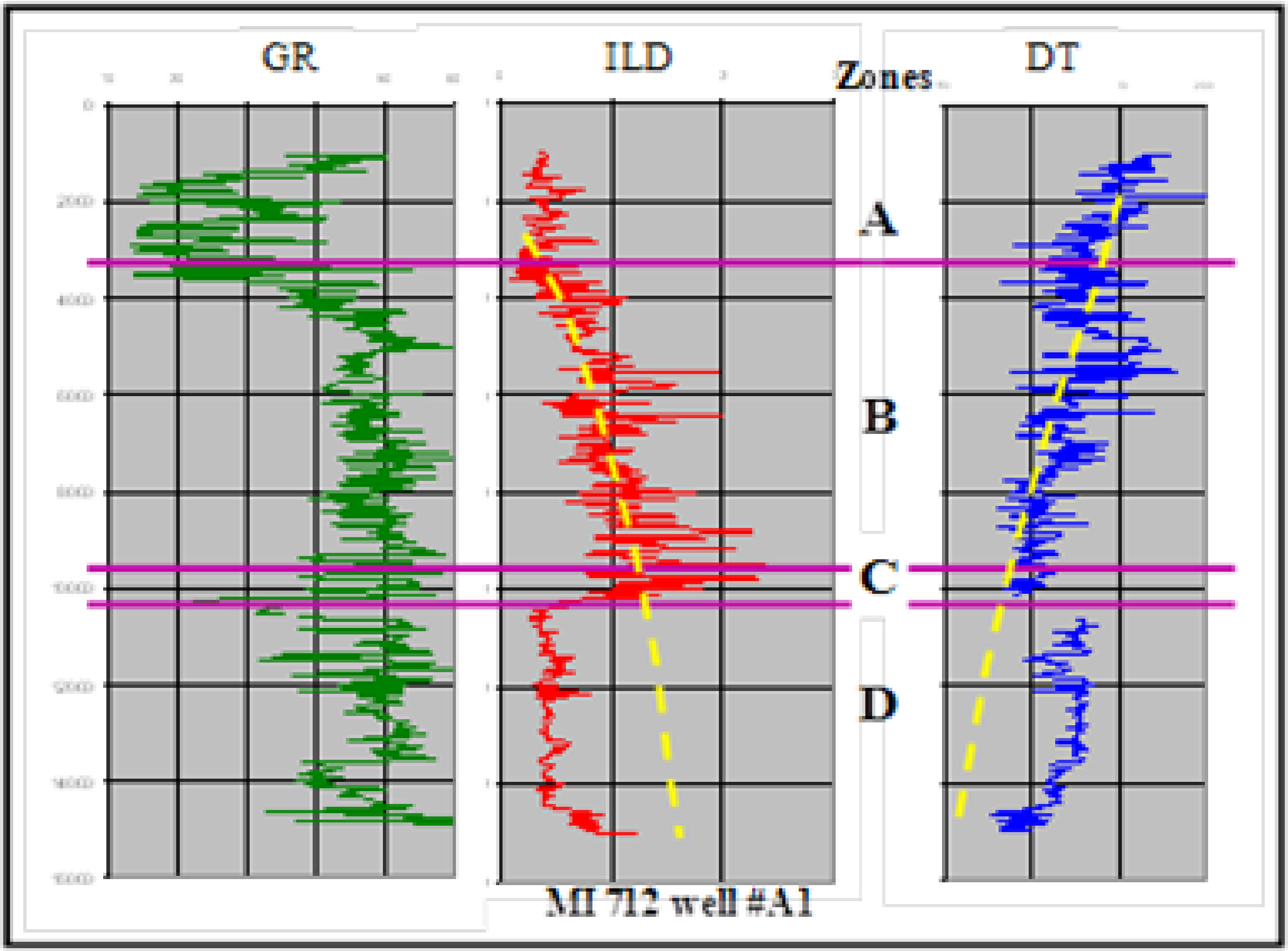


Figure 2. An example of the four subsurface compartments and their impact on resistivity and sonic slowness in offshore TX. The dashed yellow curve represents the shale Normal Compaction Trend (NCT). Extrapolated values on the yellow trend represent Rn and ΔTn.

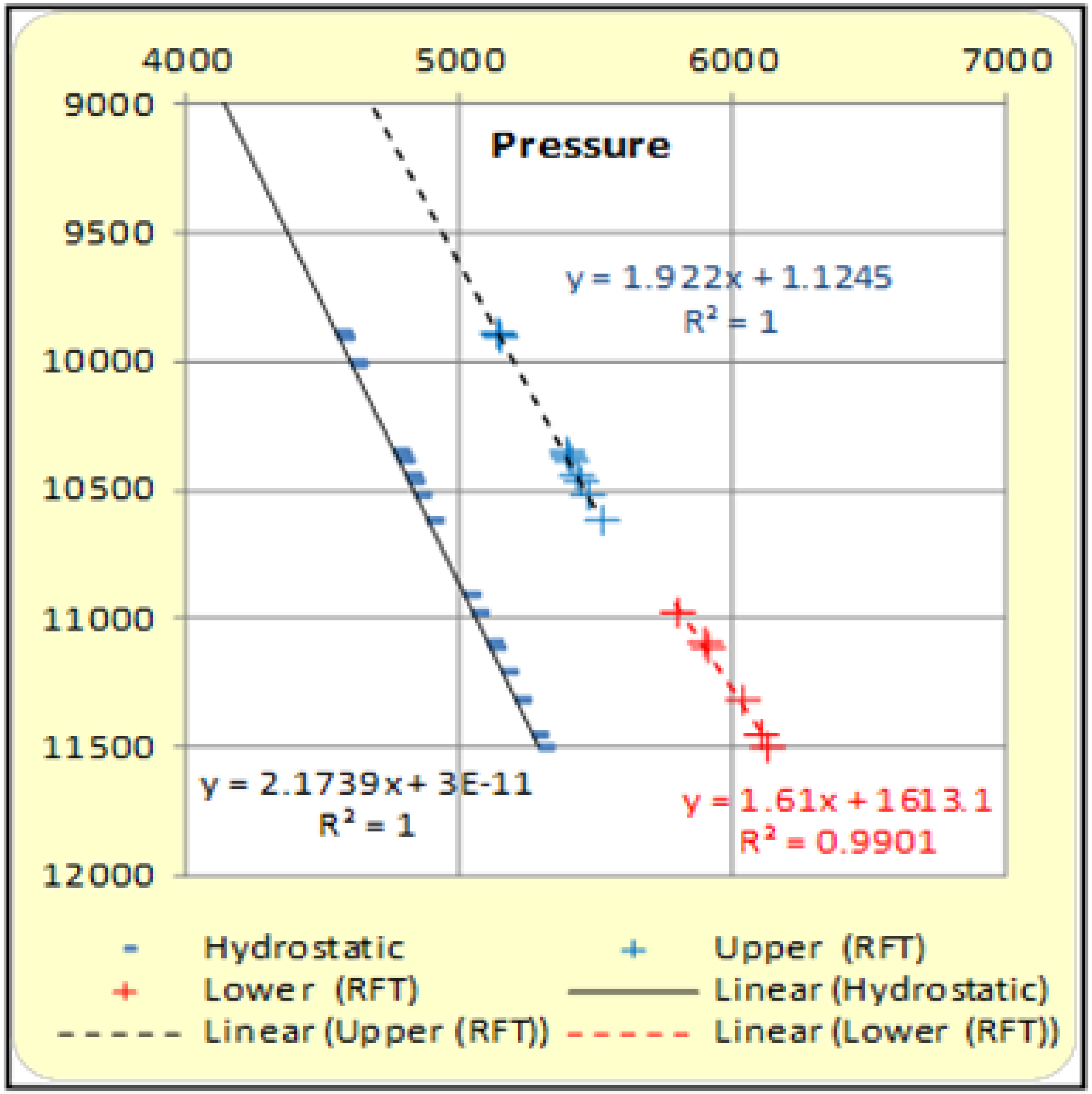


Figure 3. Measured PP (RFT) in the hydrodynamic section (Zone B) of Keathley Canyon 255 Well#1. Note the PG decreases upward due to the dewatering flow process.

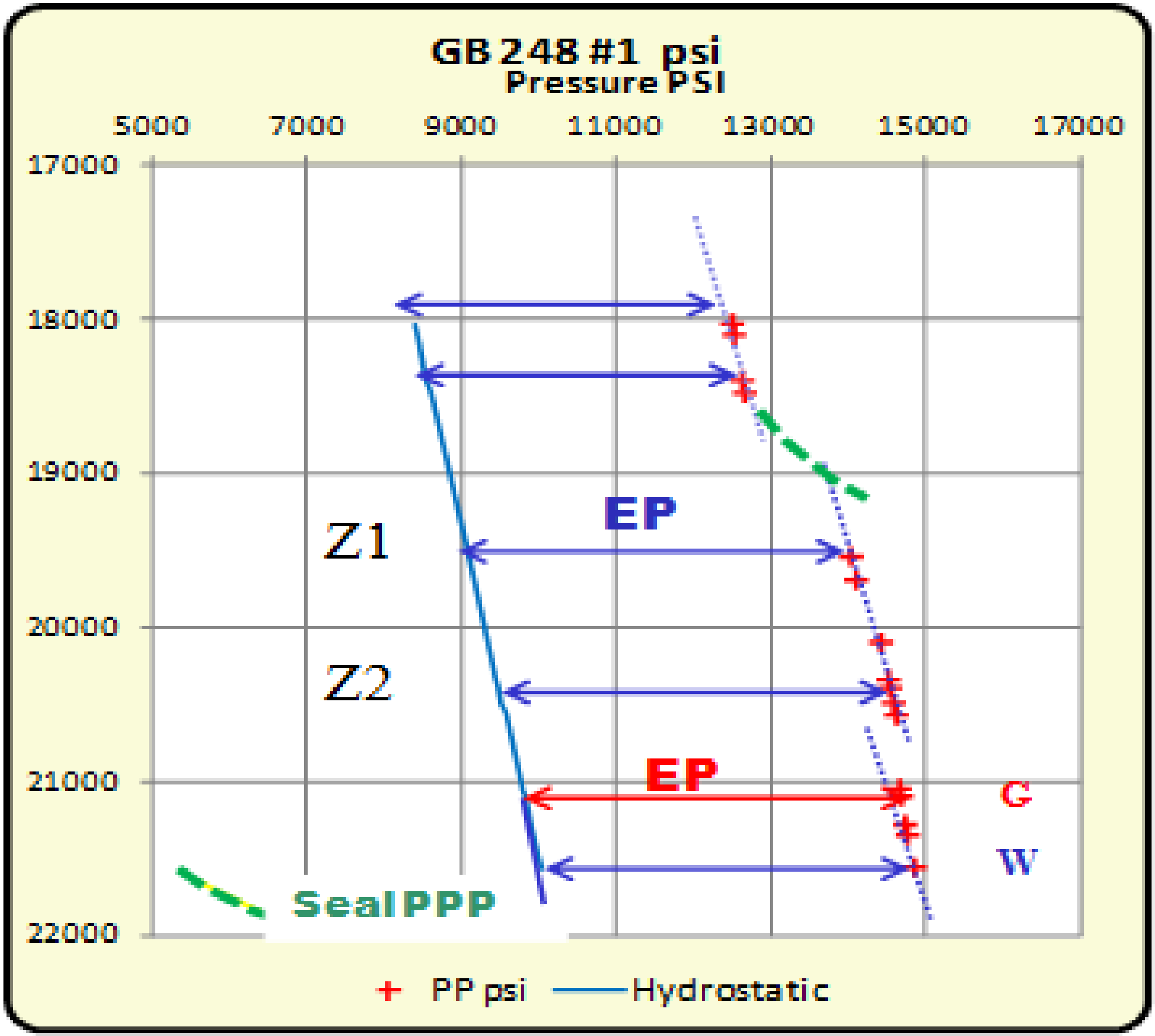


Figure 4. PP-EP calculations in reservoirs. Green dashed curve represents the predicted seal's PP.

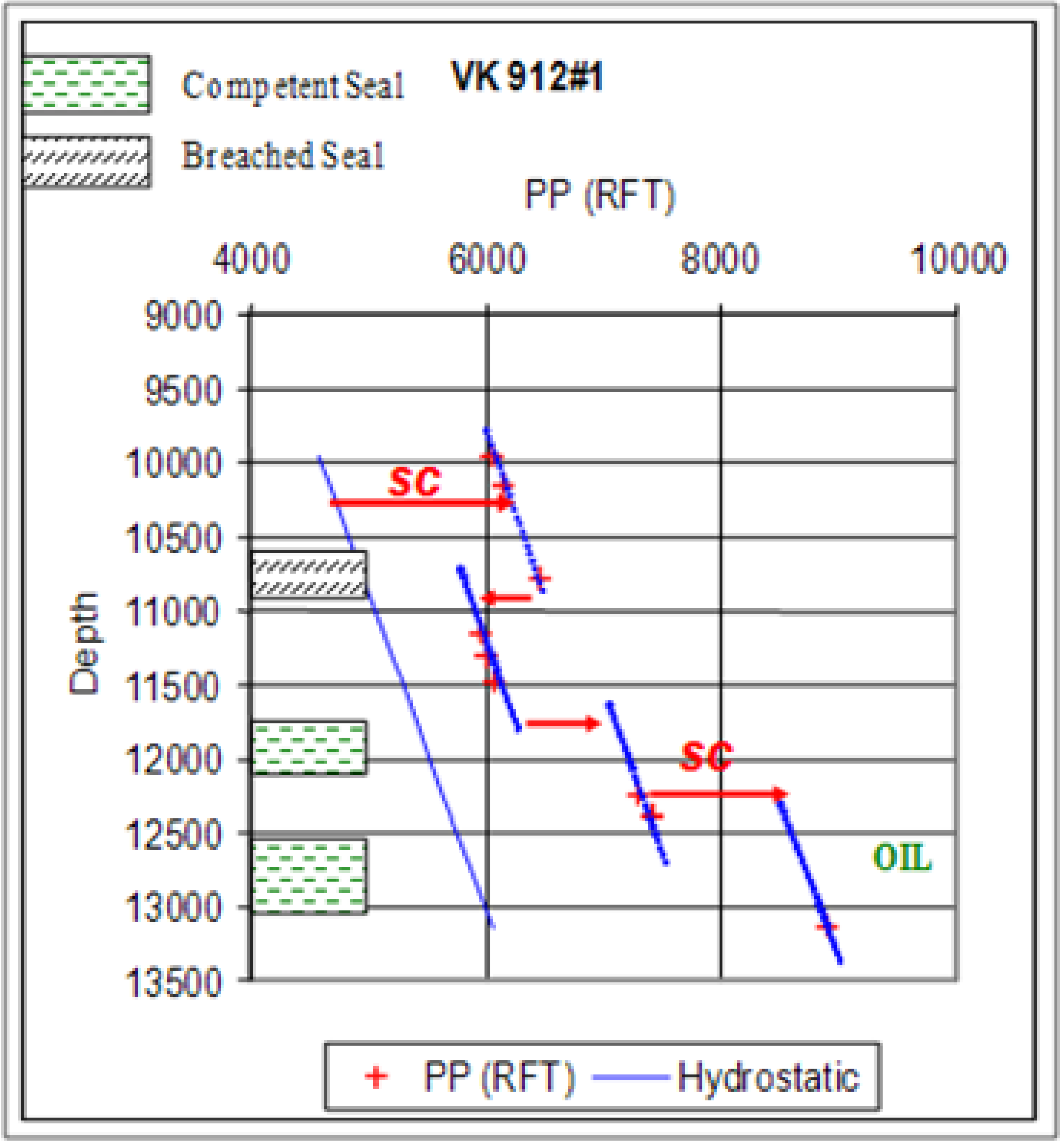


Figure 5. RFT measurement in Viosco Knoll (GoM) shows the different Sealing Capacities (SC). Progressive pressure profile (red arrow point's right) and regressive profile due to seal failure (red arrow points left).

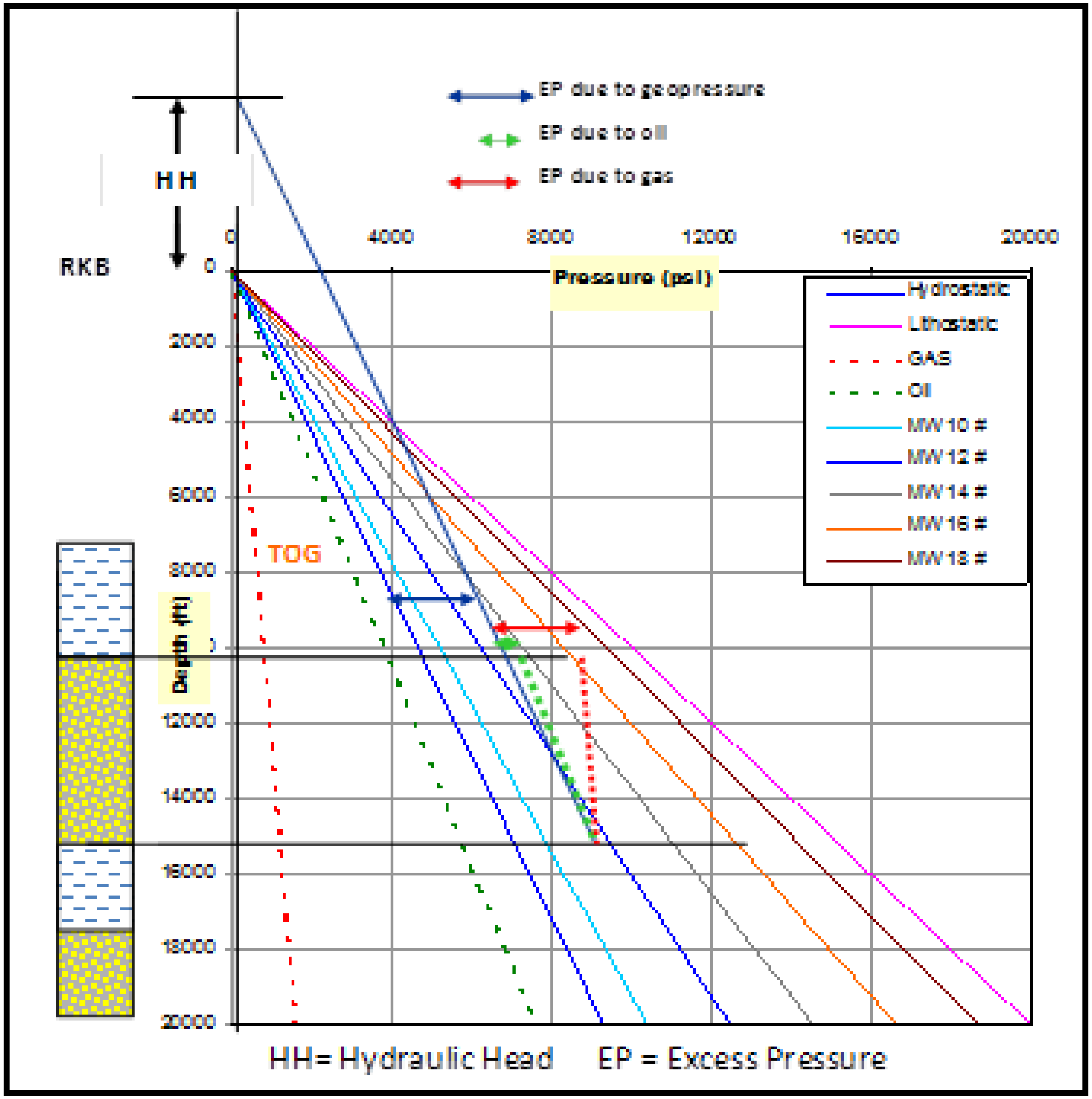


Figure 6. The relation of Hydraulic Head (HH) and Excess Pressure (EP) to the Mud Weight Fan in ppg mwe. MW is colored coded in the upper right corner.

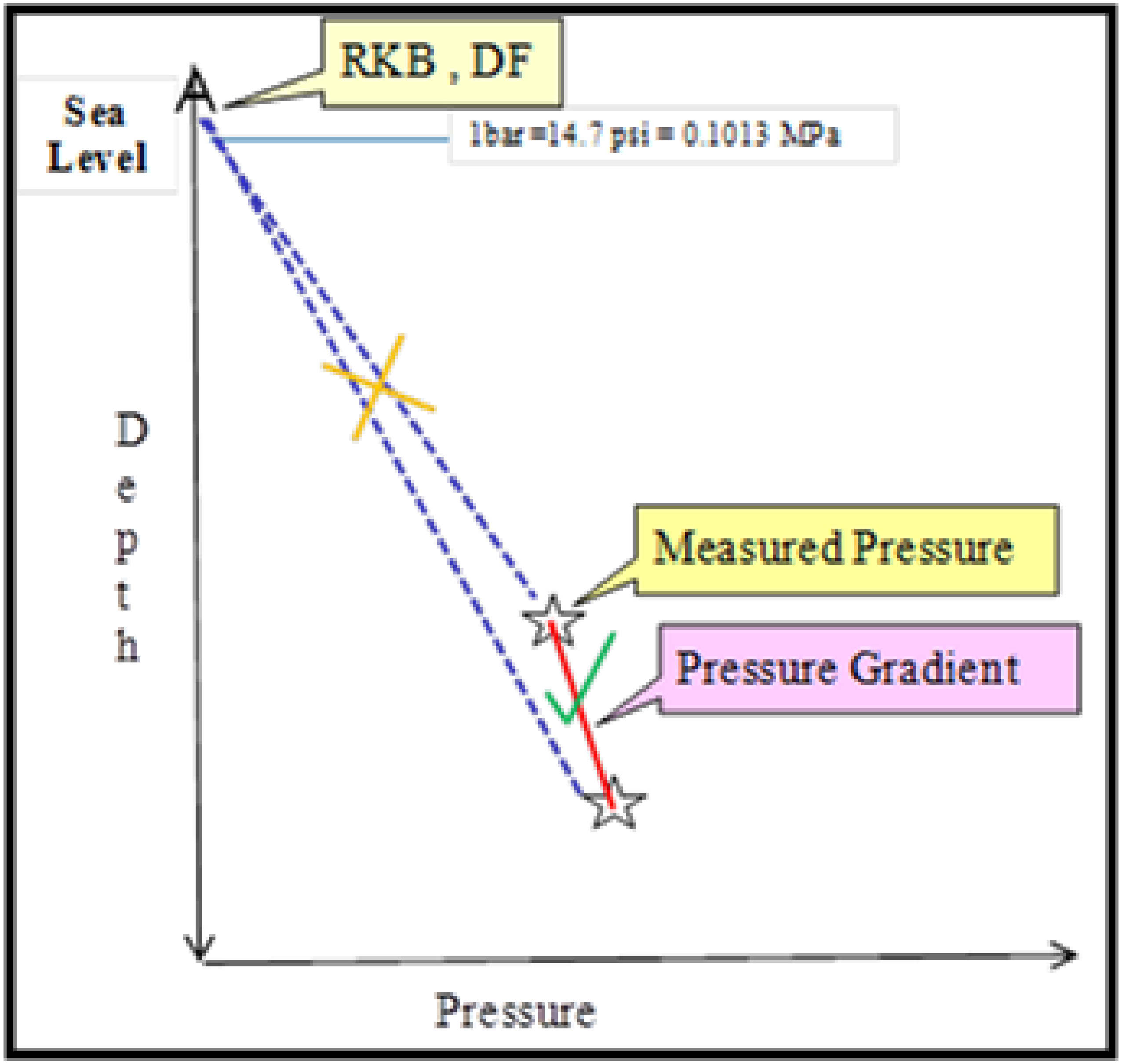
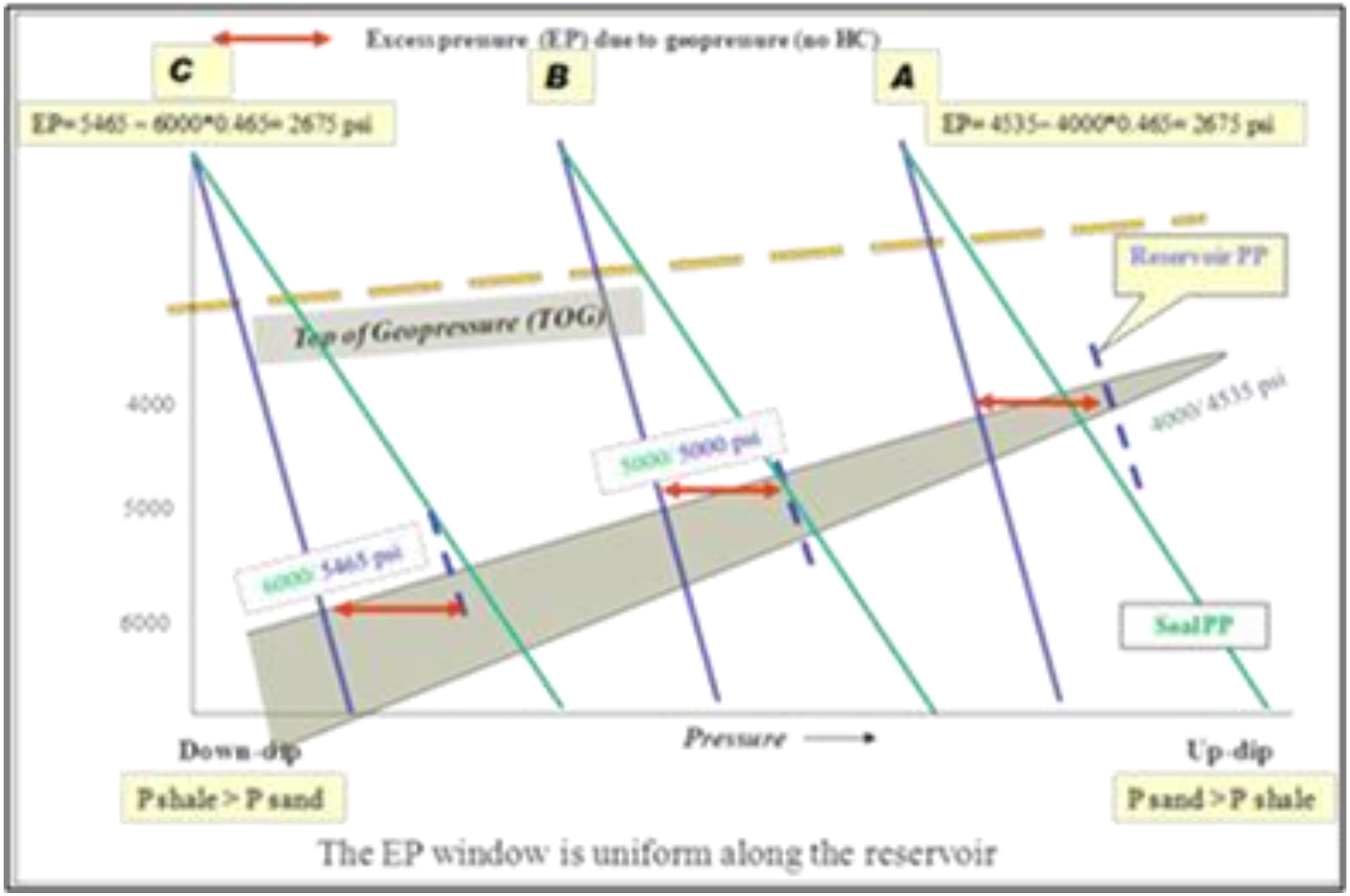


Figure 7. The correct calculation method of reservoir pressure gradient.



Well #	Depth	Hydrostat.	Reservoir P.	Shale P.	Excess P.
A	4000	1860	4535	4000	2675
B	5000	2325	5000	5000	2675
C	6000	2790	5465	6000	2675

Figure 8. Conceptual model explains the causes of disparity between sand and shale pressures due to structural tilt.

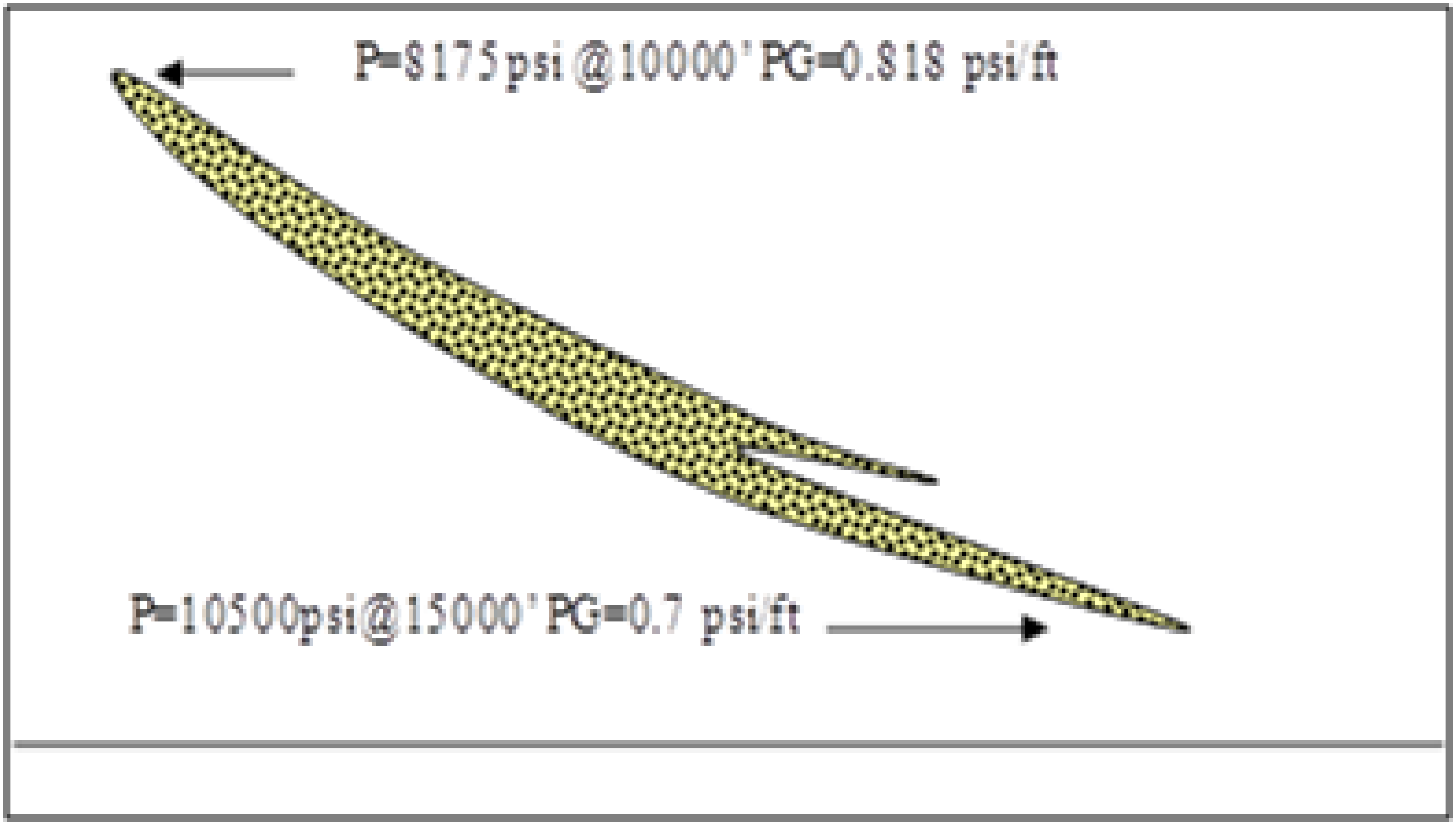


Figure 9. The confusing results of using the SL for PG calculation (Dickinson, 1953)

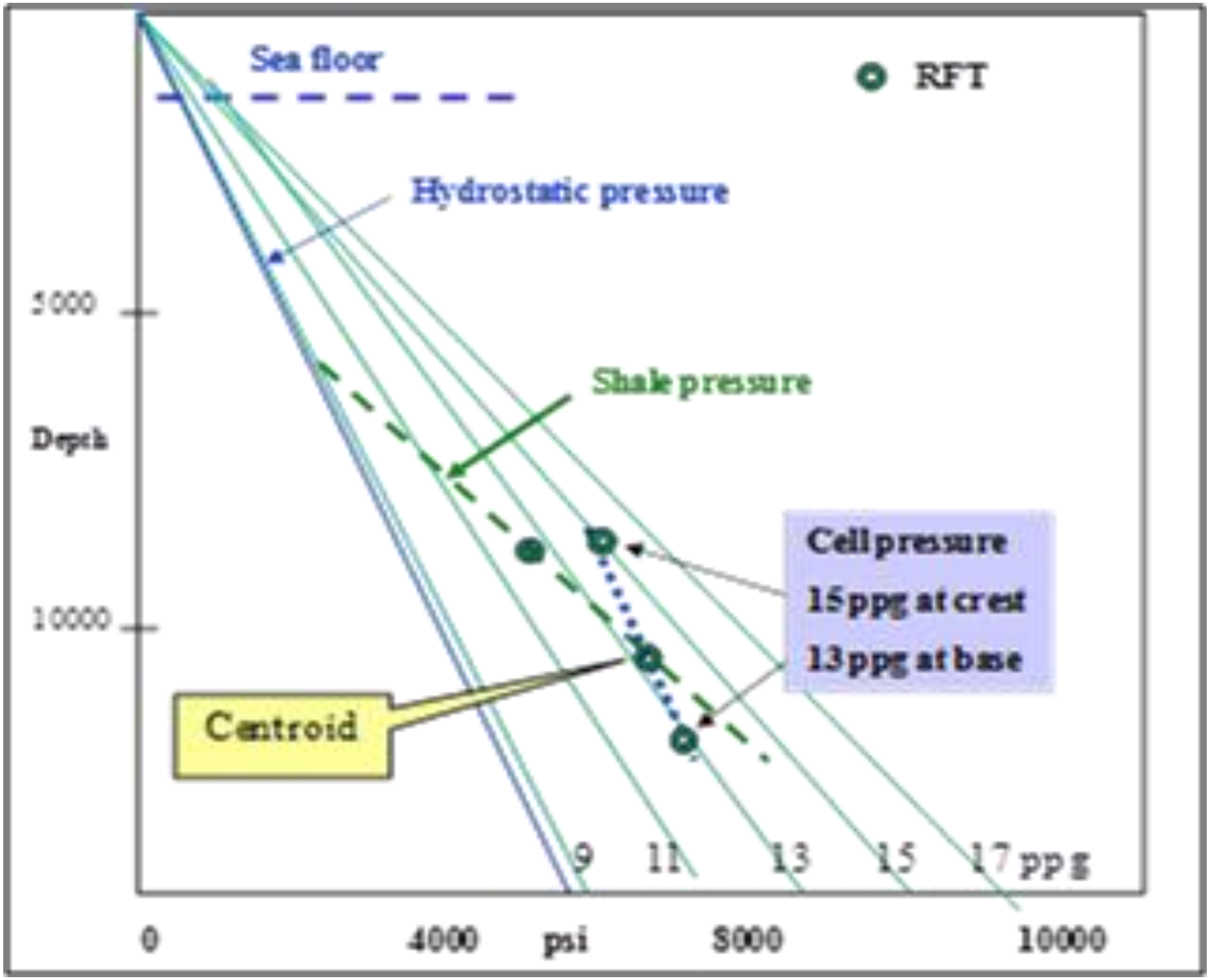


Figure 10. The Centroid hypothesis based on using the hybrid P-D plot.

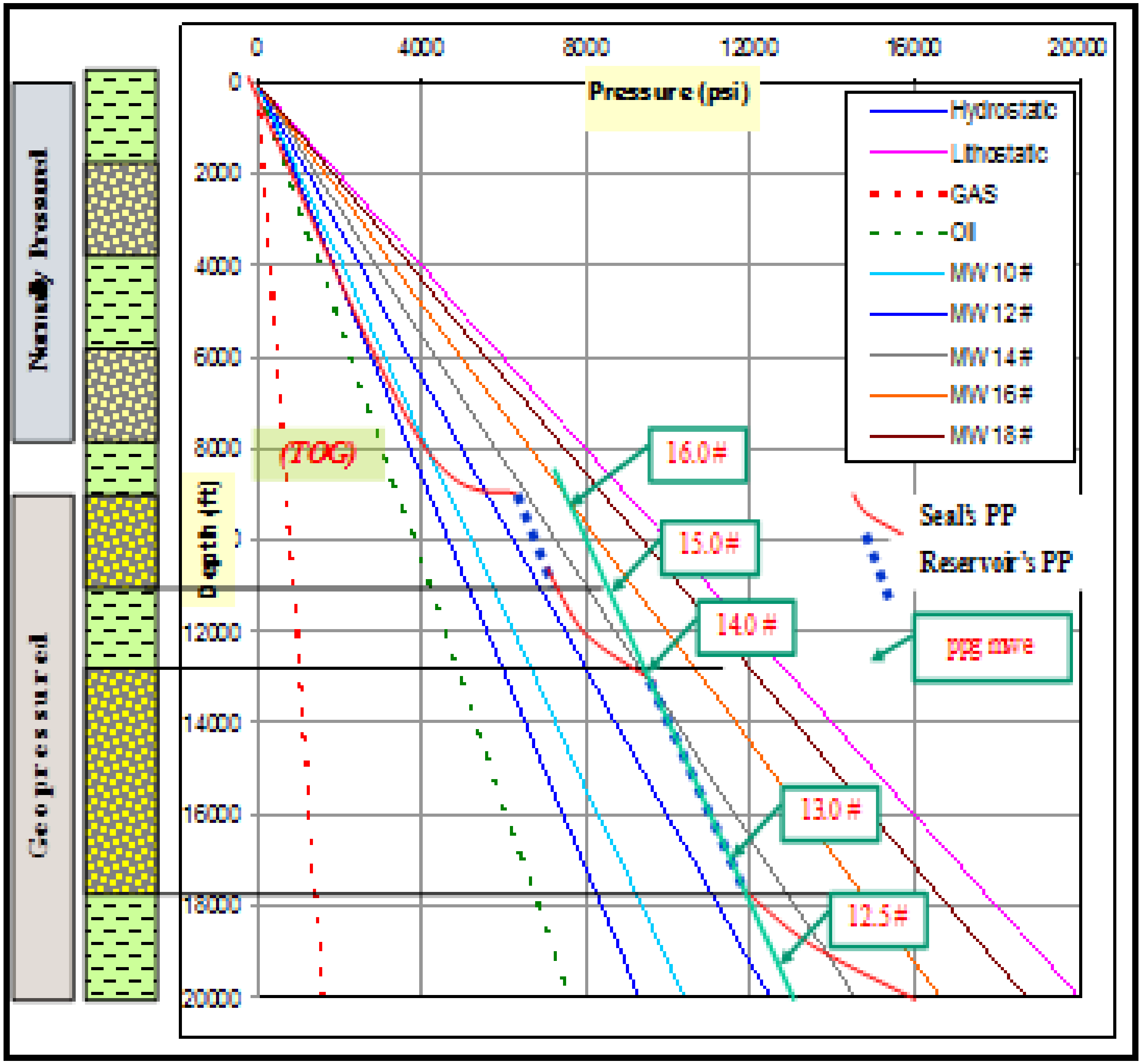


Figure 11. Causes of the reservoir's fictitious pressure regression (ppg-mwe) due to applying the hybrid P-D plot.

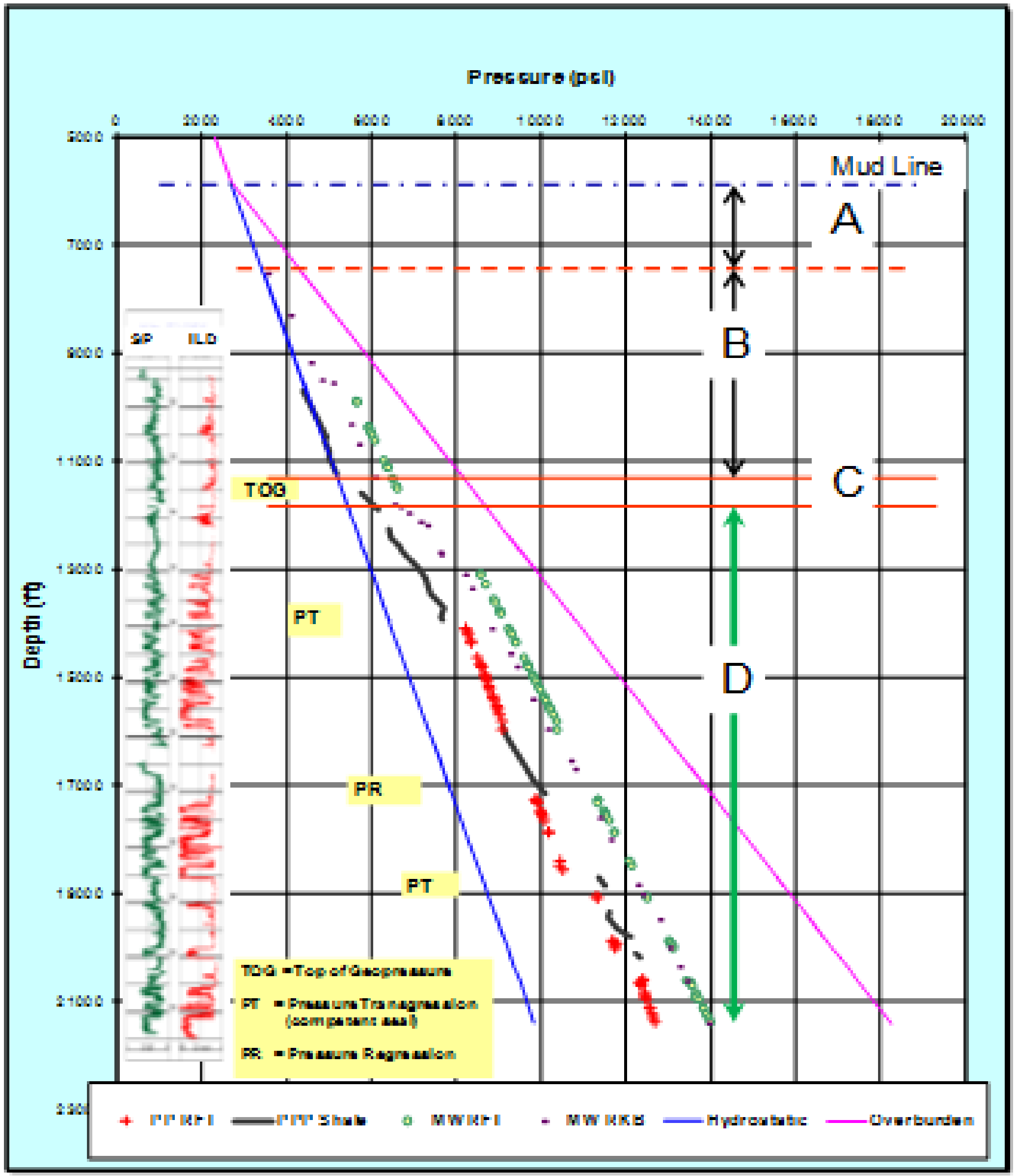


Figure 12. D-P (psi only) plot of KC 255 shows the four compartments.

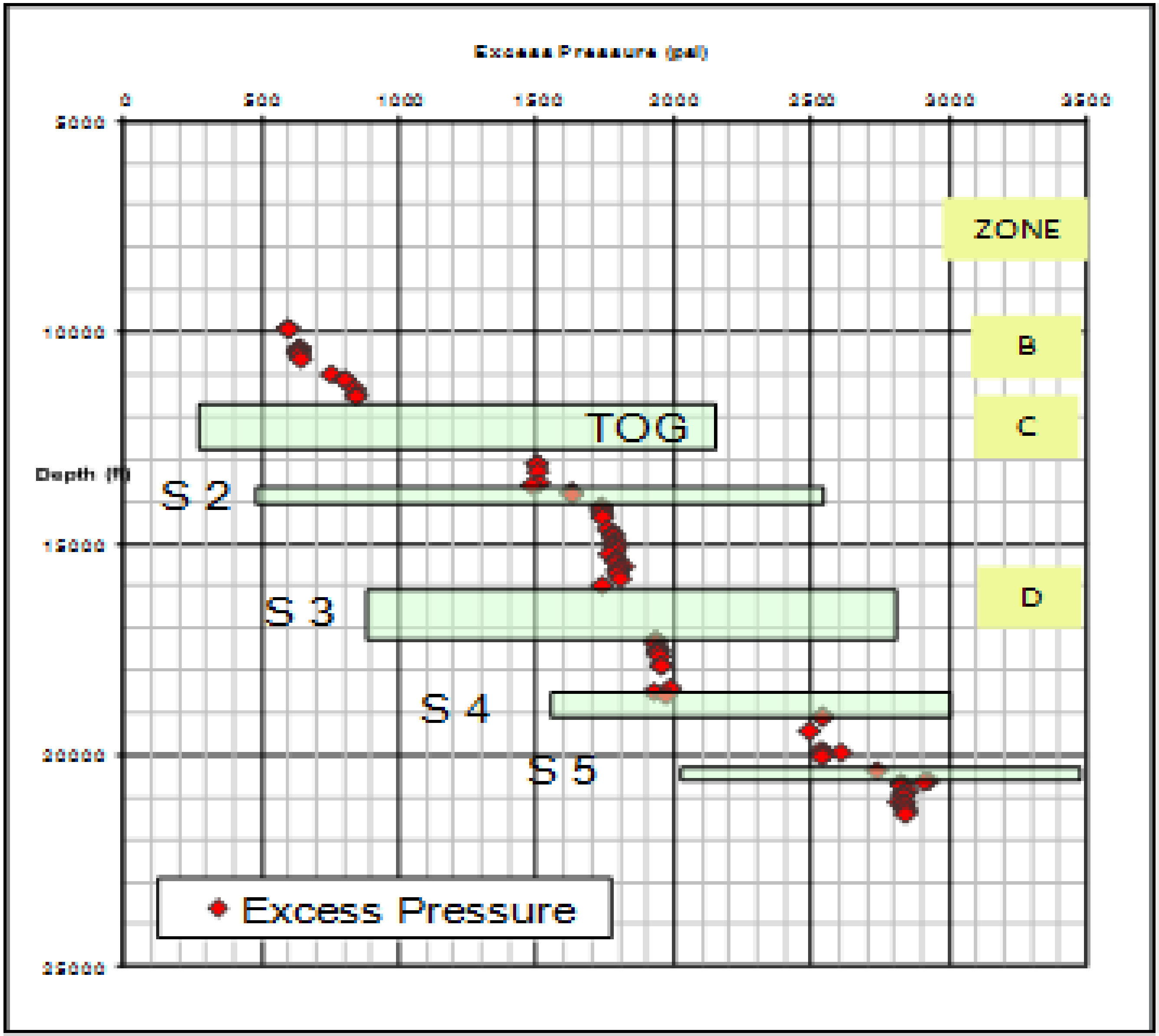
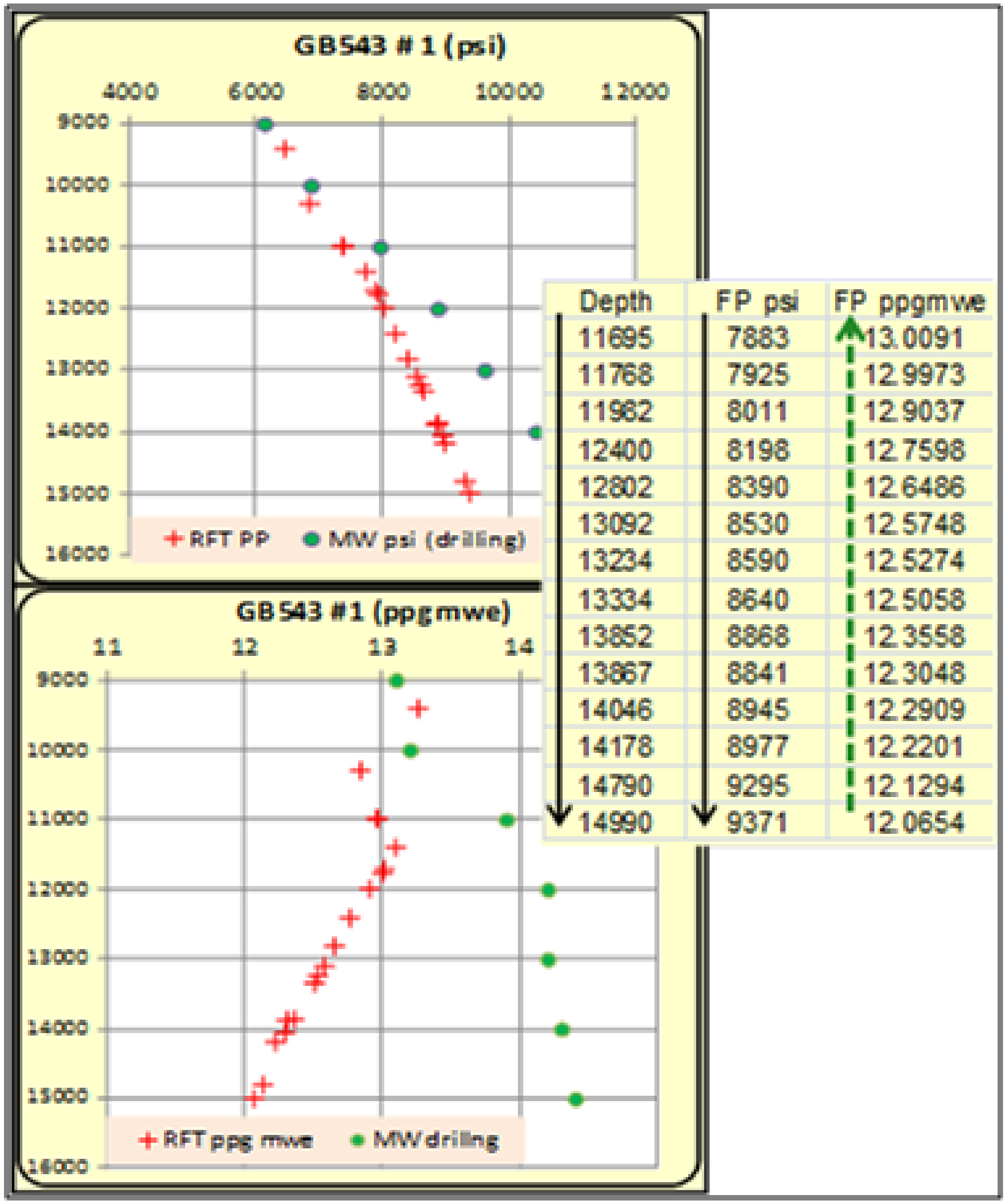


Figure 13. EP-Depth plot and SC / risk assessment evaluation.



Depth	FP psi	FP ppgmwe
11695	7883	13.0091
11768	7925	12.9973
11982	8011	12.9037
12400	8198	12.7598
12802	8390	12.6486
13092	8530	12.5748
13234	8590	12.5274
13334	8640	12.5058
13852	8868	12.3558
13867	8841	12.3048
14046	8945	12.2909
14178	8977	12.2201
14790	9295	12.1294
14990	9371	12.0654

Figure 14. P-D in psi (top) and P-D in ppg mwe (bottom) in Garden Banks 543#1. FP on the table (right panel) refers to formation pressure.