Overpressure Mechanisms in Deep Drilling in Western Offshore India*

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Search and Discovery Article #41074 (2012)
Posted November 19, 2012

*Adapted from extended abstract prepared in conjunction with oral presentation at AAPG International Conference and Exhibition, Singapore, September 16-19, 2012, AAPG©2012

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Abstract

Accurate pore pressure prediction is one of the key factors for safe drilling of wells and casing design. There are two key over pressure mechanisms. One is based on disequilibrium compaction where log responses (seismic velocity, resistivity and sonic compressional slowness) are used to predict the pore pressure profile using the standard available methods, e.g. Eaton's (1975) method. Generally, higher porosities are associated with sediments that underwent undercompaction. However, there are other mechanisms which are associated with post-depositional events, like hydrocarbon maturation, fluid expansion, and vertical pressure transfer where higher geothermal gradients are present. The undercompaction methods are unable to predict these over pressure regions.

This article provides new insights into the nature, origin, petrophysical and drilling effects of the overpressure in the Western Offshore of India. The log-derived shale porosities show the signature of undercompaction at most depth intervals. At greater depths with higher geothermal gradients, sonic compressional slowness shows the signature of hydrocarbon maturation and vertical pressure transfer where no porosity anomaly is present. Sediments of Eocene and Oligocene ages (Daman and Mahuva formations) show this characteristic more prominently. Formation pressure ranges to 13 to16 ppg in these formations. The compilation of extensive dataset ranging from formation pressure measurements to sonic, density, seismic velocity and porosity logs demonstrates the presence of compartmentalized over pressures in the region. At some depth intervals, the shale section acting as a seal is generating the overpressure in many wells. A procedure is presented to identify the different high pore pressure regimes which can be used as one of the inputs for well planning and mitigation of drilling risks. Different log based methods are studied and tested using the available

measured data to associate the mechanisms. Geological structural complexity and the associated role in the generation of overpressure are also discussed.

Introduction

Normal pressure is pore fluid pressure that equals the hydrostatic pressure of a column of formation water extending to the surface. Overpressure is pore fluid pressure greater than normal pressure. Overpressures in the subsurface pose major problems for safety and cost-effective well design. Furthermore, geopressures impact prospect and play appraisal and economics in a number of ways. The phenomenon of overpressure in sedimentary basins has been attributed to a wide range of mechanisms that can be related to the following processes: increase in stress applied to a compressible rock, fluid expansion within a restricted pore space, fluid movement, buoyancy, digenesis, and osmosis (Osborne and Swarbrick, 1997). The ability for each of these mechanisms to generate pressures above hydrostatic pressure depends on the rock and fluid properties of the sedimentary rocks and their rate of change under the normal range of basin conditions. The magnitude of overpressure varies from basin to basin. Present-day pressure distribution can be interpreted from direct measurement in permeable units (e.g. MDT and DST pressures). The pressures in low-permeability lithology cannot be measured directly but can be inferred from indirect measurements.

Overpressure detection is based on the theory that pore pressure affects compaction-dependent geophysical properties such as density, resistivity, and sonic velocity. Shale is the preferred lithology for pore pressure interpretation because they are more responsive to overpressure. Most of the techniques are linked to porosity and assume that the porosity is controlled by the maximum effective stress the sediment has experienced. However, processes like fluid expansion are accounted for using velocity vs. effective stress method proposed by Bowers (1995).

Porosity and density are bulk properties, while sonic velocity and resistivity are transport properties (Bowers et al., 2002). Bulk properties only depend on net pore volume, while transport properties are sensitive to pore sizes, shapes, and interconnectivity of pores. Storage pores can undergo inelastic volume changes with the more connecting pores capable of elastic rebound. Hence, unloading or reduction in effective stress (due to fluid expansion) cause connecting pores to increase in width without significant change in storage pore sizes. As connecting pores widen, flow path sizes are increased for conducting electrical current, and the number of intergranular contacts are reduced for transmitting sound. The final effect is more on transport properties than bulk properties, which suggests that an indicator of in-situ rebound (unloading/fluid expansion) is a depth interval in which sonic compressional velocity and resistivity data appear low in comparison to bulk density. Porosity will not show any significant changes during this process.

The basin-centered gas accumulations (BCGAs) are typically characterized by regionally pervasive accumulations that are gas saturated, abnormally pressured, commonly lack a downdip water contact, and have low permeability reservoirs. The first description of a low-permeability gas province that is commonly associated with basin-centered systems is by Masters (1979). The accumulations range from single, isolated reservoirs a few feet thick to multiple, stacked reservoirs several thousand feet thick. Two types of BCGSs are recognized: (1) a direct type characterized by having gas-prone source rocks, and (2) an indirect type characterized by having liquid-prone source rocks. The majority of known BCGAs are the direct type. The relatively closed nature of this rock sequence in the more deeply buried parts of the basin facilitates examination of the geologic processes related to gas generation and occurrence. Abnormally high formation pressures in these low permeability rocks are always associated with gas-bearing reservoirs and are caused by the generation of thermogenic gas. The occurrence of overpressured gas-bearing reservoirs is, in part, dependent on the organic-richness and thermal maturity of the source rocks. The initiation, or threshold, of significantly large volumes of thermogenic gas occurs at a temperature of about 190 to 200°F (88" to 93°C) and a vitrinite reflectance of about 0.80 Ro. During thermal generation of gas, a dewatering process is initiated that eventually reduces water content to irreducible levels. The remaining irreducible water is immobile, producing a relatively closed hydrologic system in which dissolution processes and porosity enhancement become ineffective. Thus, while porosity enhancing processes are effectively impeded, porosity reducing processes continue, eventually producing effective seals. The top of gas-bearing overpressured reservoirs cut across structural and stratigraphic boundaries, thereby demonstrating the diminished role of structure and stratigraphy. In a nutshell, overpressure is basically caused by two volume changing processes: (1) shrinkage of maturing kerogen accompanied by creation of compactable non-equilibrium porosity, and (2) creation of fluid hydrocarbons whose volume exceeds both original and created porosity.

The basin-centered gas accumulations (BCGAs) are observed in western offshore India where abnormal pressure distribution is measured in the Panna, Daman, Mahuva and Mahim formations in different areas. The mechanism of overpressures appears to be principally compaction disequilibrium, especially in the upper parts of the pressure compartments. In the deeper parts of the basin lows, where the sediments are likely to be over matured, hydrocarbon generation/oil to gas cracking is expected to provide an additional pressuring mechanism. The top of gas-bearing overpressured reservoirs cuts across structural and stratigraphic boundaries, thereby demonstrating the diminished role of structure and stratigraphy. This paper reviews different mechanisms for overpressure and presents case studies on pore pressure analysis from western offshore.

Overpressure Mechanisms

The causes of overpressure can be divided into four general categories: undercompaction (compaction disequilibrium), fluid expansion (aqua thermal expansion; hydrocarbon generation and gas cracking; mineral transformations), lateral transfer, and tectonic loading. The conditions that produce normal pressure and the four types of overpressure are described below.

(a) Normal Pressure

Normally pressured formations are able to maintain hydraulic communication with the surface during burial. Consequently, their pore fluid can easily be squeezed out to accommodate compaction, and their pore pressure follows the hydrostatic pressure curve for formation water. Effective stresses in normally pressured environments continually increase with depth. On velocity vs. effective vertical stress plot, normal pressure points lie on the virgin curve as seen Figure 1.

(b) Compaction Disequilibrium

With increase in overburden pressure during loading, there can be incomplete dewatering with part of the weight of the load being added to the pore-fluid pressure. This mechanism is commonly termed “disequilibrium compaction,” and the physical manifestation in the bulk rock is excess pore pressure and a higher porosity relative to the normally pressured and fully compacted rock at the same depth. The onset of overpressure is controlled by the loading rate and the porosity and permeability evolution of the sediment during burial. For an impermeable seal and an incompressible pore fluid, pore pressure would increase at the same rate as the overburden stress once sealing occurred. However, undercompaction will not drive pore pressure toward the overburden stress curve. This also means that undercompaction cannot cause effective stress reductions as seen in Figure 1.

(c) Fluid Expansion

Overpressure can be generated by fluid expansion in low permeability rocks, where pore fluid volume increases with lesser change in porosity and at a rate that does not permit effective dissipation of fluid. Different causes of fluid expansion can be clay dehydration, smectite-illite transformation, maturation of source rocks to oil and gas, gas cracking, aquathermal pressuring and mineral precipitation/cementation reactions. Increasing temperature during burial causes both rocks and fluids to expand. The volume expansion of rock is approximately one order of magnitude smaller for rock than for water and therefore can be ignored. The fluid volume change due to aquathermal expansion is 1.65% for an increase in temperature of 40 deg C (Osborne and Swarbrick, 1998). Volume changes occur when kerogen transforms to oil and gas and when oil cracks to gas. The volume change depends on the kerogen source and the density and volume of the petroleum products generated during maturation. This leads to reduction of effective stress with less change in sonic velocity (Figure 1).

(d) Lateral Transfer

Lateral transfer can occur along dipping sand enclosed in shale. The sand transmits pore fluid and pore pressure from deeper shale up dip (Yardley and Swarbrick, 2000). Lateral transfer can generate crestal pore pressures high enough to fracture overlying shale seals, especially when there are long gas columns. Sometimes this can be caused by charging along faults.

(e) Tectonic Loading

Trapped pore fluid squeezed by tectonically driven lateral stresses induces overpressure in the same way that undercompaction does. However, unlike undercompaction, tectonic loading is capable of generating high overpressure (Yasser and Addis, 2002). This also means that tectonic loading can cause vertical effective stress to decrease, but in tectonic environments, compaction is no longer controlled by vertical effective stress alone. Areas of thrusting and folding typically contain overpressured rocks, and the magnitude of overpressure in these regions relates to both the amount of stress and strain in the rocks and their physical properties.

Western Offshore: Overpressure Detection Using Well Logs

An appropriate knowledge of formation pressure is required for safe well design and avoiding drilling risks. Usually pore pressure is estimated using petrophysical measurements like sonic compressional slowness (velocity), density, resistivity, porosity, etc. Normal pressure sonic trend is demarcated with decreasing sonic compressional slowness in shale with depth due to compaction in the same depositional unit. In over-pressurized formations, sonic compressional slowness in shale will remain the same or increase with depth (Figure 2). All these estimated pore pressure values need to be calibrated using actual measured formation values using MDT, XPT and well test pressure in reservoir zones.

The general features of Tapti-Daman block, such as geological setup, stratigraphy, source rock, pore pressure distribution, and drilling events such as gas shows and kicks show the similarity with the characteristics of BCGAs as described by Law (2002). The basin forms a broad syncline rising towards the north against the ENE-WSW trending marginal faults and in the east towards the NNW-SSE trending basin margin, and in the south against the E-W trending Diu Fault. The Tapti-Daman block has Tertiary clastics from Paleocene to Recent. The Tapti-Daman block has three major lows, viz., the Navsari Low, the Purna Low and the Daman Low. The organic matter appears to be dominated by Type III mixed with Type II organic matter.

The formation pressure distribution in the block shows that the upper formations are at hydrostatic pressure and overpressures are observed generally below 2100 m depth. The Daman Formation, which consists of a thick sandy permeable section, is generally at hydrostatic pressure except in the south Daman area where it is over pressured. The Mahuva section is observed to be over pressured over a large area. Overpressures in the range of 13.5-17.0 ppg are observed in the basinal low trends (Figure 3 and Figure 5). The maximum overpressures are observed along the synclinal axis of the Purna and Daman lows. The top of overpressure is observed to vary spatially and be irregular and thus cuts across stratigraphic boundaries. In the northern part high pressures are observed in the Panna Formation, in the central part they are observed in the Daman and Mahuva formations, and in the southern part the high pressure sequence begins in the Mahim Formation.

Mud weights in the range of 14-17.5 ppg are used to avoid gas kicks in the wells drilled through the overpressure regime at deeper depth intervals. Primarily gas is methane in composition indicating thermal cracking. Sand sections with gas shows have lower permeability with porosity in the range of 8-15%. However, water bearing sand zones lying over gas zones (similar to BCGA system) has higher porosity, being in the range of 25-35% (Figure 4). Thin layers of shale and irreducible water formed under BCGA acts as a seal barrier. The relationship between thermal maturity and top of overpressure is variable over the block. The top of overpressure is generally within the onset of maturity (0.5% VRo). As seen in Figure 6 and Figure 7, there is no marked change in the trend of porosity, but sonic and density measurements show anomaly with the normal compaction trend.

Conclusions

Pore pressure distribution in the Western Offshore of India gives better insight into structural changes and helps to optimize mud weight for future wells. Gas generation, due to thermal maturation near source rock, leads to overpressure in deeper depths in the Mahim, Panna and Mahuva formations in Western Offshore. Compaction disequilibrium (undercompaction) is the main reason for higher pressure at shallower depth. All the different types of overpressure mechanisms can be distinguished based on geophysical measurements and velocity-effective stress plots. Density shows lesser changes as compared to sonic velocity and resistivity values during unloading. There is no marked change in porosity in comparison to other petrophysical logs during the fluid expansion overpressure mechanism.

Acknowledgements

The authors thank Schlumberger for their support and permission to publish this article. The authors wish to thank all the members of DCS, Schlumberger who provided support during this study.

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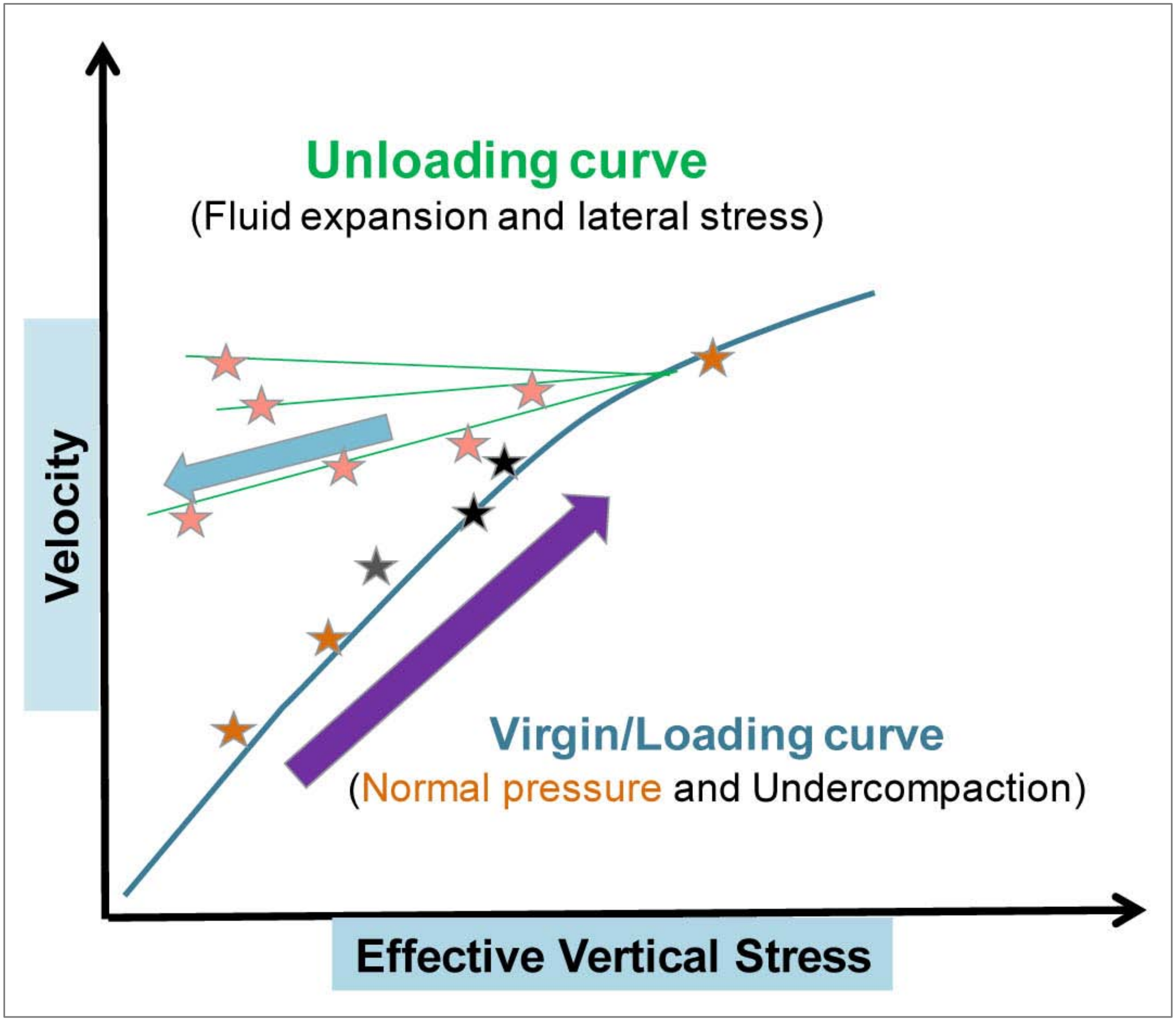

Figure 1. Velocity vs. effective vertical stress plot with different pore pressure mechanisms.

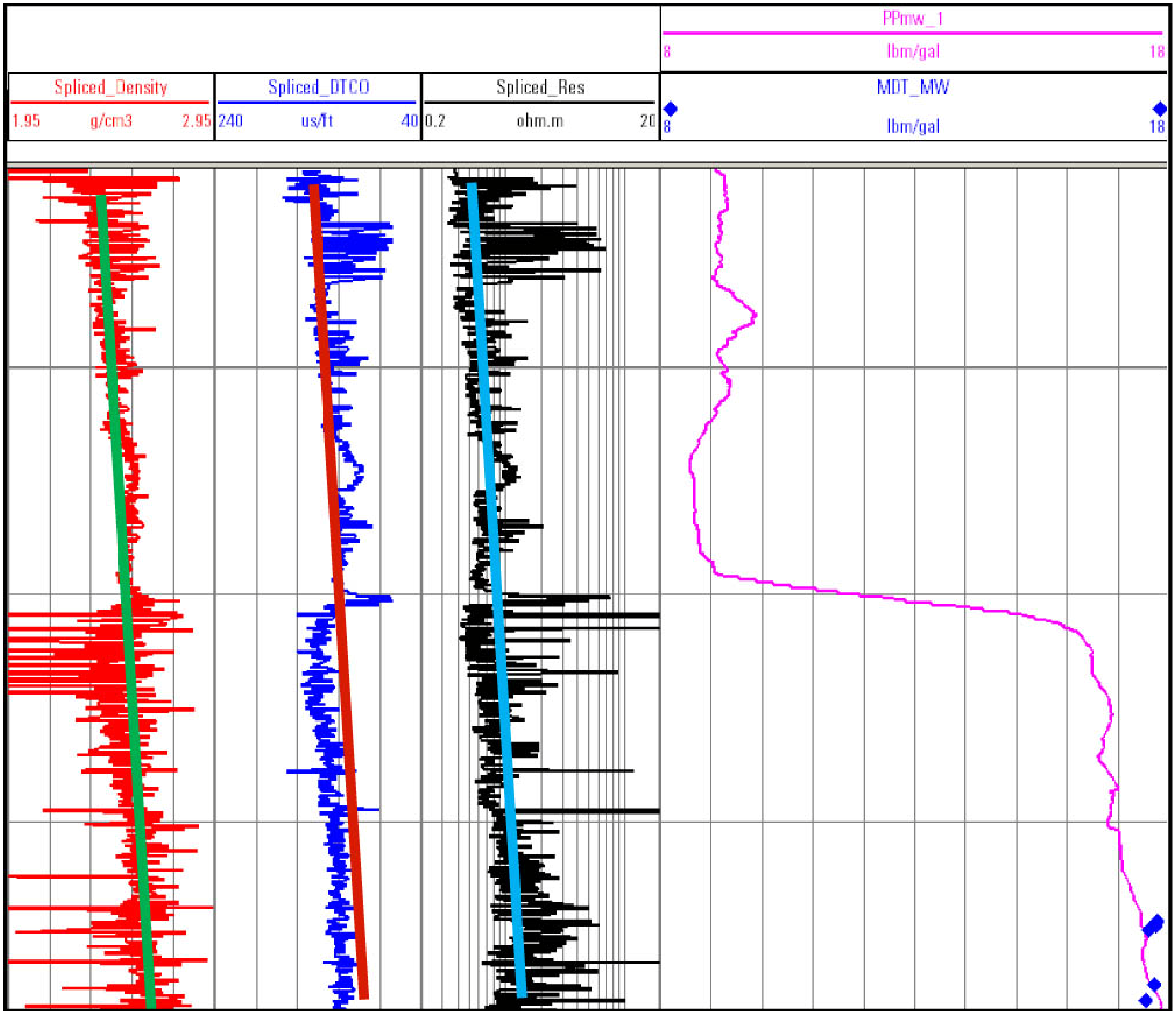

Figure 2. Overpressure due to departure of DTCO, density and resistivity from normal compaction trend.

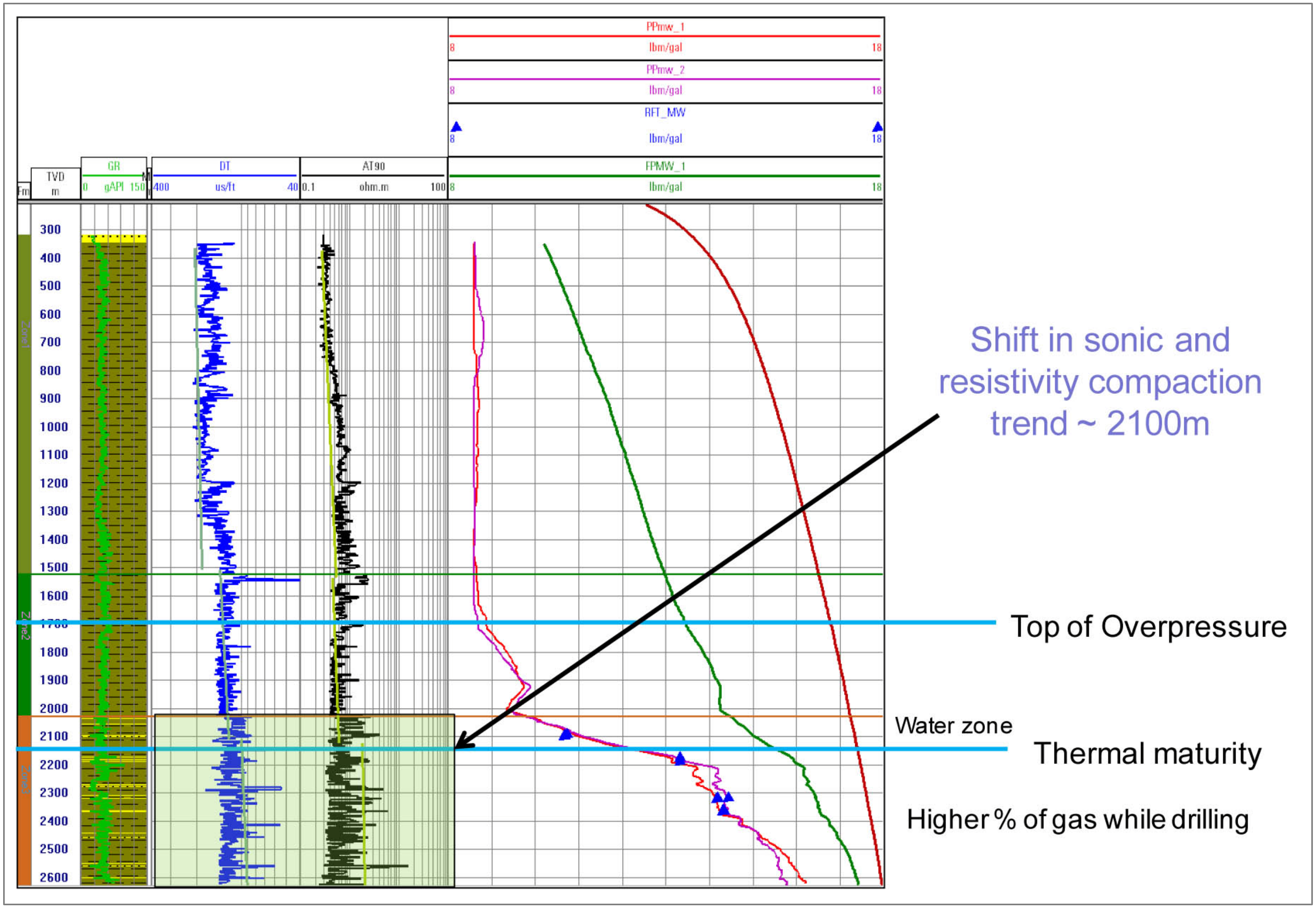

Figure 3. Pore pressure model for vertical well A.

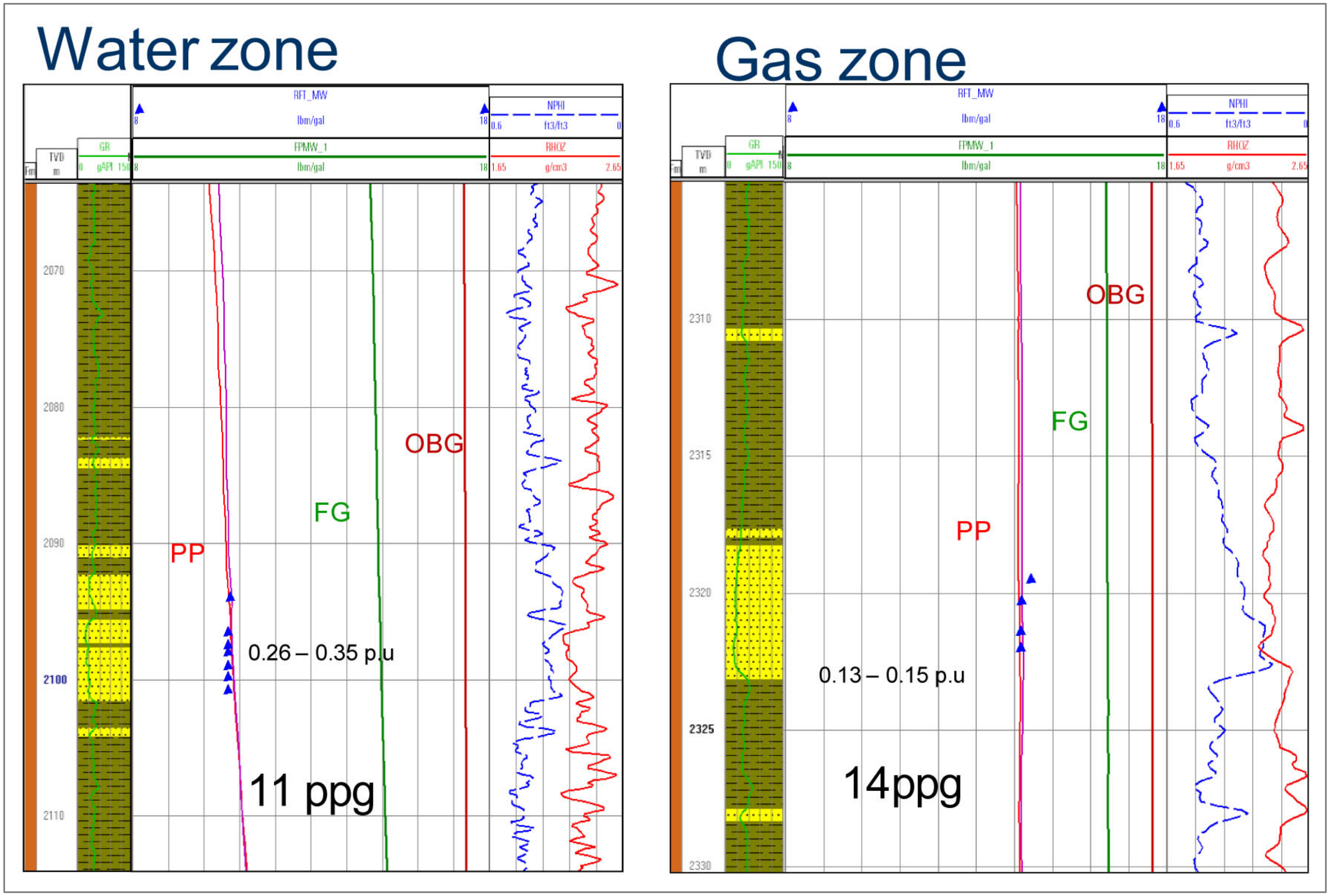

Figure 4. Petrophysical log values vs. measured formation pressure in well A.

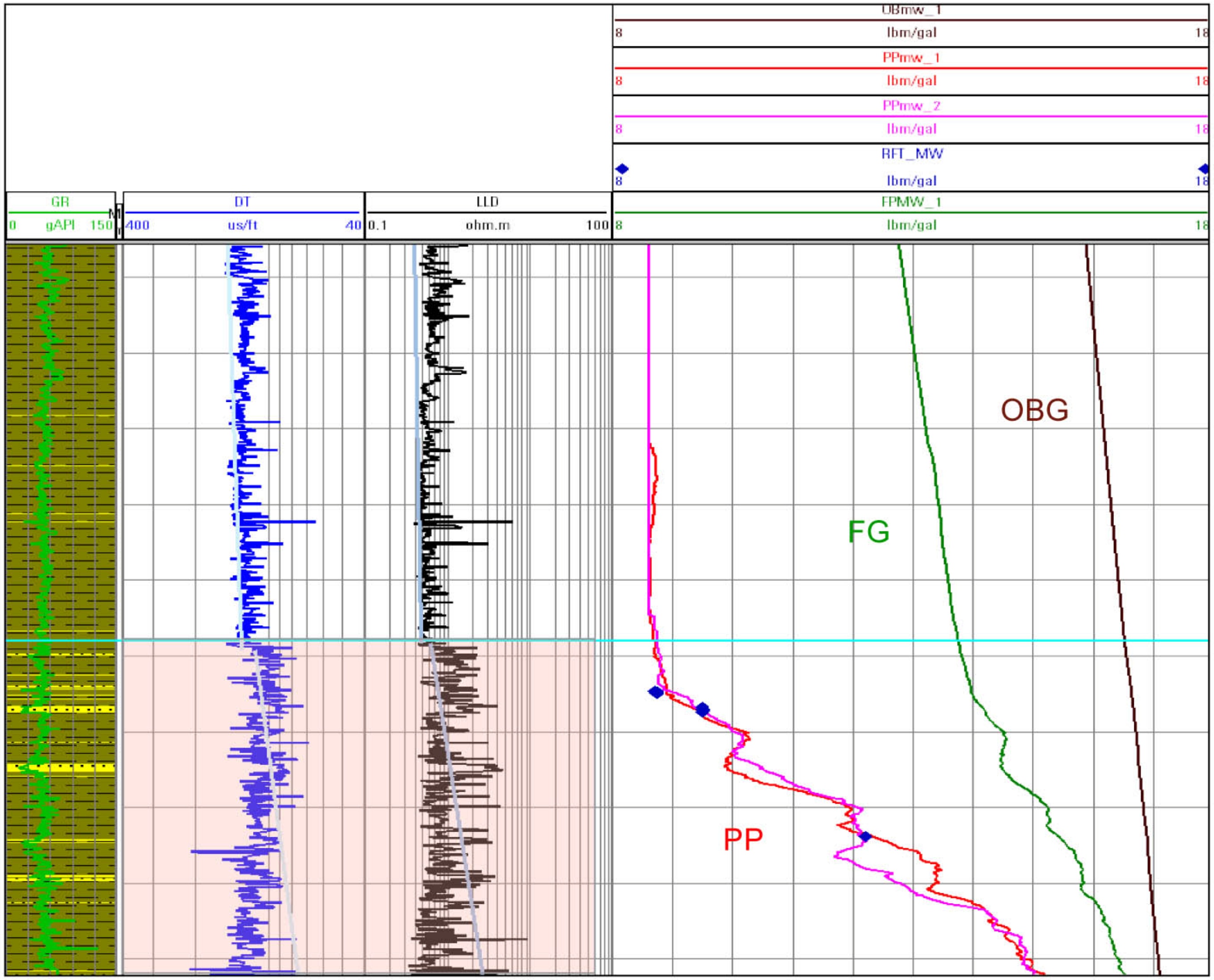

Figure 5. Pore pressure profile for well B drilled near well A.

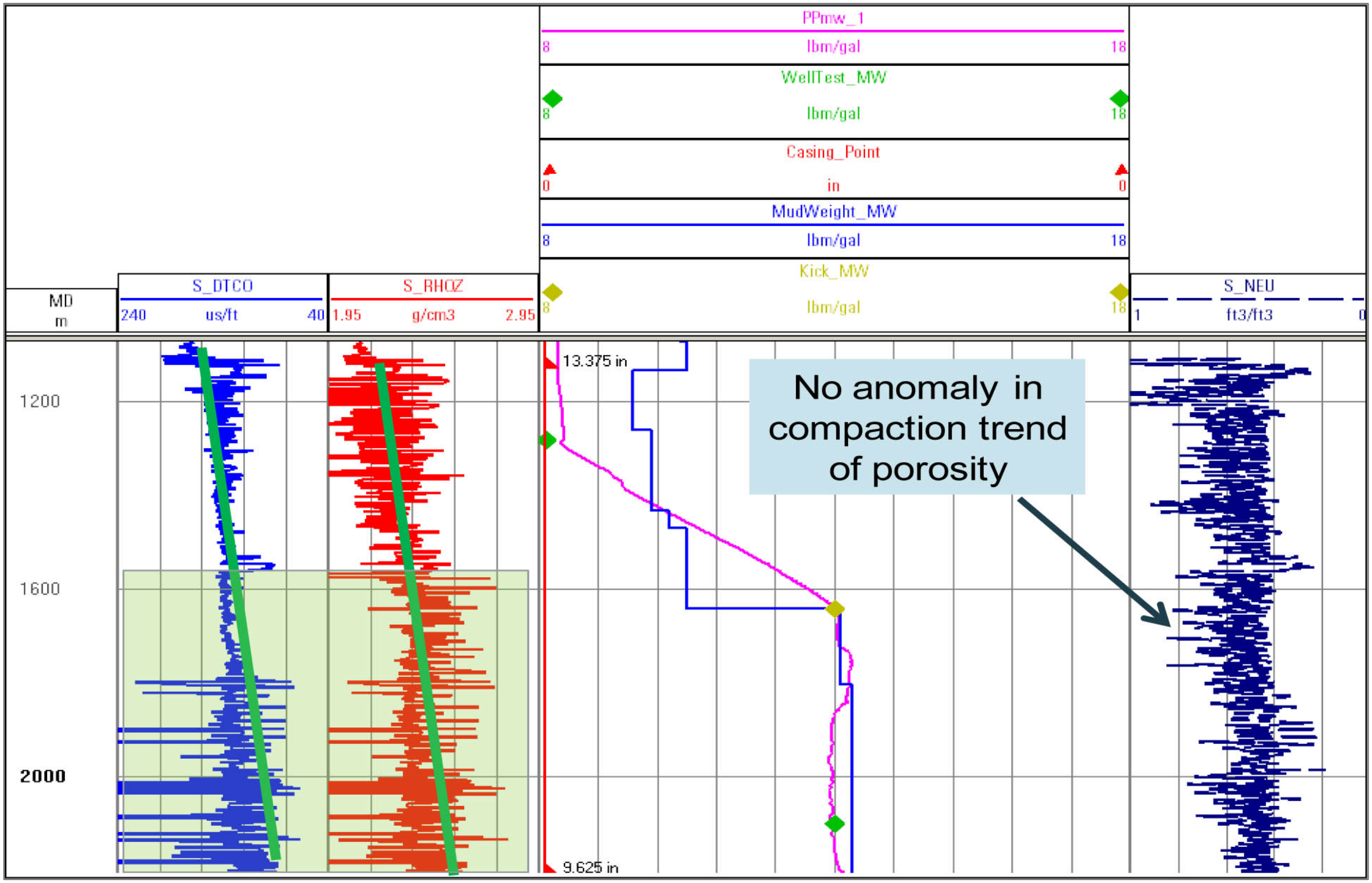

Figure 6. Pore pressure profile for well C drilled near wells A and B.

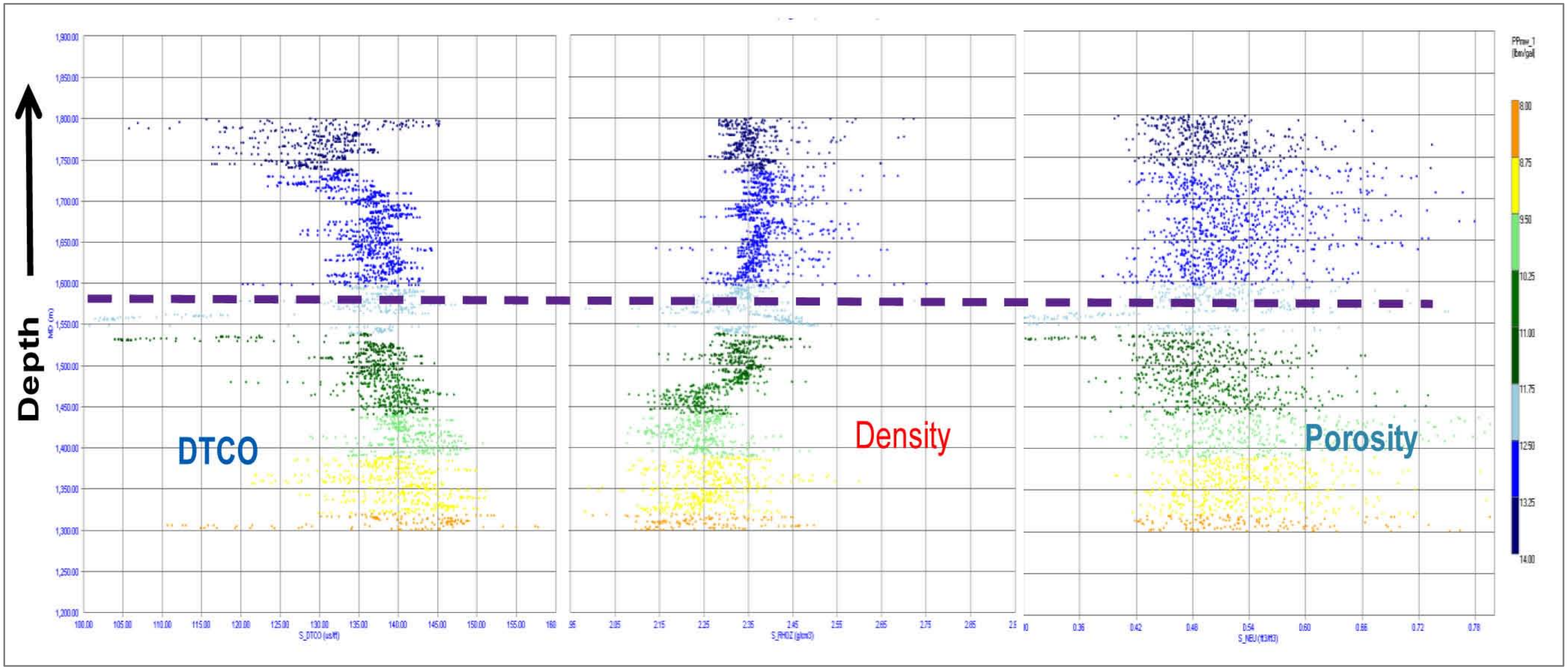

Figure 7. Change in values of different petrophysical parameters in overpressure zone.